Exhibit 45

AQS_SIT	POC	SAMPLE_	DAILY_M	UNITS	DAILY_A	DAILY_OB	PERCENT_	AQS_PAR/
49-047-20(	1	1/1/2011	0.039	ppm	33	24	100	44201
49-047-20(	1	1/2/2011	0.041	ppm	35	22	92	44201
49-047-20(	1	1/3/2011	0.049	ppm	42	20	83	44201
49-047-20(	1	1/4/2011	0.058	ppm	49	24	100	44201
49-047-20(	1	1/5/2011	0.069	ppm	80	24	100	44201
49-047-20(	1	1/6/2011	0.078	ppm	106	24	100	44201
49-047-20(	1	1/7/2011	0.092	ppm	142	24	100	44201
49-047-20(	1	1/8/2011	0.098	ppm	156	24	100	44201
49-047-20(	1	1/9/2011	0.1	ppm	161	22	92	44201
49-047-20(	1	1/10/2011	0.049	ppm	42	20	83	44201
49-047-20(	1	1/11/2011	0.042	ppm	36	24	100	44201
49-047-20(	1	1/12/2011	0.062	ppm	58	24	100	44201
49-047-20(	1	1/13/2011	0.073	ppm	93	24	100	44201
49-047-20(	1	1/14/2011	0.066	ppm	71	24	100	44201
49-047-20(	1	1/15/2011	0.069	ppm	80	24	100	44201
49-047-20(	1	1/16/2011	0.086	ppm	127	22	92	44201
49-047-20(	1	1/17/2011	0.075	ppm	100	20	83	44201
49-047-20(	1	1/18/2011	0.054	ppm	46	24	100	44201
49-047-20(	1	1/19/2011	0.07	ppm	84	24	100	44201
49-047-20(	1	1/20/2011	0.052	ppm	44	24	100	44201
49-047-20(	1	1/21/2011	0.072	ppm	90	24	100	44201
49-047-20(	1	1/22/2011	0.075	ppm	100	24	100	44201
49-047-20(	1	1/23/2011	0.049	ppm	42	22	92	44201
49-047-20(	1	1/24/2011	0.066	ppm	71	20	83	44201
49-047-20(	1	1/25/2011	0.056	ppm	47	24	100	44201
49-047-20(	1	1/26/2011	0.083	ppm	119	24	100	44201
49-047-20(	1	1/27/2011	0.087	ppm	129	24	100	44201
49-047-20(	1	1/28/2011	0.091	ppm	140	24	100	44201
49-047-20(	1	1/29/2011	0.092	ppm	142	24	100	44201
49-047-20(	1	1/30/2011	0.102	ppm	166	22	92	44201
49-047-20(	1	1/31/2011	0.088	ppm	132	20	83	44201
49-047-20(	1	2/1/2011	0.043	ppm	36	24	100	44201
49-047-20(	1	2/2/2011	0.039	ppm	33	24	100	44201
49-047-20(	1	2/3/2011	0.043	ppm	36	24	100	44201
49-047-20(	1	2/4/2011	0.053	ppm	45	24	100	44201
49-047-20(	1	2/5/2011	0.066	ppm	71	24	100	44201
49-047-20(	1	2/6/2011	0.074	ppm	97	22	92	44201
49-047-20(	1	2/7/2011	0.071	ppm	87	20	83	44201
49-047-20(	1	2/8/2011	0.042	ppm	36	24	100	44201
49-047-20(	1	2/9/2011	0.045	ppm	38	24	100	44201
49-047-20(	1	2/10/2011	0.058	ppm	49	24	100	44201
49-047-20(	1	2/11/2011	0.074	ppm	97	24	100	44201
49-047-20(	1	2/12/2011	0.096	ppm	151	24	100	44201
49-047-20(	1	2/13/2011	0.116	ppm	201	22	92	44201
49-047-20(	1	2/14/2011	0.139	ppm	210	20	83	44201
49-047-20(	1	2/15/2011	0.133	ppm	208	24	100	44201
49-047-20(	1	2/16/2011	0.139	ppm	210	24	100	44201
49-047-20(	1	2/17/2011	0.055	ppm	47	24	100	44201
49-047-20(	1	2/18/2011	0.054	ppm	46	24	100	44201
49-047-20(	1	2/19/2011	0.055	ppm	47	24	100	44201
49-047-20(	1	2/20/2011	0.058	ppm	49	22	92	44201

49-047-20(	1	2/21/2011	0.068	ppm	77	20	83	44201
49-047-20(	1	2/23/2011	0.09	ppm	137	24	100	44201
49-047-20(	1	2/24/2011	0.11	ppm	187	24	100	44201
49-047-20(	1	2/25/2011	0.082	ppm	116	24	100	44201
49-047-20(	1	2/26/2011	0.054	ppm	46	24	100	44201
49-047-20(	1	2/27/2011	0.06	ppm	51	22	92	44201
49-047-20(	1	2/28/2011	0.07	ppm	84	20	83	44201
49-047-20(	1	3/1/2011	0.076	ppm	101	24	100	44201
49-047-20(	1	3/2/2011	0.092	ppm	142	24	100	44201
49-047-20(	1	3/3/2011	0.093	ppm	145	24	100	44201
49-047-20(	1	3/4/2011	0.062	ppm	58	24	100	44201
49-047-20(	1	3/5/2011	0.066	ppm	71	24	100	44201
49-047-20(	1	3/6/2011	0.06	ppm	51	22	92	44201
49-047-20(	1	3/7/2011	0.052	ppm	44	20	83	44201
49-047-20(	1	3/8/2011	0.051	ppm	43	24	100	44201
49-047-20(	1	3/9/2011	0.052	ppm	44	24	100	44201
49-047-20(	1	3/10/2011	0.057	ppm	48	24	100	44201
49-047-20(	1	3/11/2011	0.055	ppm	47	24	100	44201
49-047-20(	1	3/12/2011	0.05	ppm	42	24	100	44201
49-047-20(	1	3/13/2011	0.053	ppm	45	22	92	44201
49-047-20(	1	3/14/2011	0.047	ppm	40	20	83	44201
49-047-20(	1	3/15/2011	0.052	ppm	44	24	100	44201
49-047-20(	1	3/16/2011	0.047	ppm	40	24	100	44201
49-047-20(	1	3/17/2011	0.049	ppm	42	24	100	44201
49-047-20(	1	3/18/2011	0.053	ppm	45	24	100	44201
49-047-20(	1	3/19/2011	0.056	ppm	47	24	100	44201
49-047-20(	1	3/20/2011	0.052	ppm	44	22	92	44201
49-047-20(	1	3/21/2011	0.051	ppm	43	20	83	44201
49-047-20(	1	3/22/2011	0.048	ppm	41	24	100	44201
49-047-20(	1	3/23/2011	0.054	ppm	46	18	75	44201
49-047-20(	1	3/24/2011	0.055	ppm	47	24	100	44201
49-047-20(	1	3/25/2011	0.048	ppm	41	24	100	44201
49-047-20(	1	3/26/2011	0.051	ppm	43	24	100	44201
49-047-20(	1	3/27/2011	0.055	ppm	47	22	92	44201
49-047-20(	1	3/28/2011	0.052	ppm	44	20	83	44201
49-047-20(	1	3/29/2011	0.048	ppm	41	24	100	44201
49-047-20(	1	3/30/2011	0.041	ppm	35	24	100	44201
49-047-20(	1	3/31/2011	0.048	ppm	41	20	83	44201
49-047-20(	1	4/1/2011	0.053	ppm	45	24	100	44201
49-047-20(	1	4/2/2011	0.045	ppm	38	24	100	44201
49-047-20(	1	4/3/2011	0.055	ppm	47	22	92	44201
49-047-20(	1	4/4/2011	0.05	ppm	42	20	83	44201
49-047-20(	1	4/5/2011	0.049	ppm	42	24	100	44201
49-047-20(	1	4/6/2011	0.06	ppm	51	24	100	44201
49-047-20(	1	4/7/2011	0.055	ppm	47	24	100	44201
49-047-20(	1	4/8/2011	0.054	ppm	46	24	100	44201
49-047-20(	1	4/9/2011	0.059	ppm	50	24	100	44201
49-047-20(	1	4/10/2011	0.053	ppm	45	22	92	44201
49-047-20(	1	4/11/2011	0.051	ppm	43	20	83	44201
49-047-20(	1	4/12/2011	0.054	ppm	46	24	100	44201
49-047-20(	1	4/13/2011	0.055	ppm	47	24	100	44201
49-047-20(	1	4/14/2011	0.06	ppm	51	24	100	44201

49-047-20(	1	4/15/2011	0.063	ppm	61	24	100	44201
49-047-20(	1	4/16/2011	0.052	ppm	44	24	100	44201
49-047-20(	1	4/17/2011	0.044	ppm	37	22	92	44201
49-047-20(	1	4/18/2011	0.034	ppm	29	20	83	44201
49-047-20(	1	4/19/2011	0.048	ppm	41	24	100	44201
49-047-20(	1	4/20/2011	0.046	ppm	39	24	100	44201
49-047-20(	1	4/21/2011	0.052	ppm	44	24	100	44201
49-047-20(	1	4/22/2011	0.061	ppm	54	24	100	44201
49-047-20(	1	4/23/2011	0.057	ppm	48	24	100	44201
49-047-20(	1	4/24/2011	0.049	ppm	42	22	92	44201
49-047-20(	1	4/25/2011	0.054	ppm	46	20	83	44201
49-047-20(	1	4/26/2011	0.053	ppm	45	24	100	44201
49-047-20(	1	4/27/2011	0.056	ppm	47	24	100	44201
49-047-20(	1	4/28/2011	0.056	ppm	47	24	100	44201
49-047-20(	1	4/29/2011	0.057	ppm	48	24	100	44201
49-047-20(	1	4/30/2011	0.047	ppm	40	20	83	44201
49-047-20(	1	5/1/2011	0.05	ppm	42	22	92	44201
49-047-20(	1	5/2/2011	0.056	ppm	47	20	83	44201
49-047-20(	1	5/3/2011	0.053	ppm	45	24	100	44201
49-047-20(	1	5/4/2011	0.064	ppm	64	24	100	44201
49-047-20(	1	5/6/2011	0.057	ppm	48	24	100	44201
49-047-20(	1	5/7/2011	0.065	ppm	67	24	100	44201
49-047-20(	1	5/8/2011	0.055	ppm	47	22	92	44201
49-047-20(	1	5/9/2011	0.072	ppm	90	20	83	44201
49-047-20(	1	5/10/2011	0.059	ppm	50	24	100	44201
49-047-20(	1	5/11/2011	0.042	ppm	36	24	100	44201
49-047-20(	1	5/12/2011	0.055	ppm	47	24	100	44201
49-047-20(	1	5/13/2011	0.052	ppm	44	24	100	44201
49-047-20(	1	5/14/2011	0.053	ppm	45	24	100	44201
49-047-20(	1	5/15/2011	0.046	ppm	39	22	92	44201
49-047-20(	1	5/16/2011	0.051	ppm	43	20	83	44201
49-047-20(	1	5/17/2011	0.051	ppm	43	24	100	44201
49-047-20(	1	5/18/2011	0.06	ppm	51	24	100	44201
49-047-20(	1	5/19/2011	0.061	ppm	54	24	100	44201
49-047-20(	1	5/20/2011	0.052	ppm	44	24	100	44201
49-047-20(	1	5/21/2011	0.054	ppm	46	24	100	44201
49-047-20(	1	5/22/2011	0.05	ppm	42	22	92	44201
49-047-20(	1	5/23/2011	0.058	ppm	49	20	83	44201
49-047-20(	1	5/24/2011	0.056	ppm	47	24	100	44201
49-047-20(	1	5/25/2011	0.059	ppm	50	24	100	44201
49-047-20(	1	5/27/2011	0.056	ppm	47	24	100	44201
49-047-20(	1	5/28/2011	0.047	ppm	40	24	100	44201
49-047-20(	1	5/30/2011	0.052	ppm	44	20	83	44201
49-047-20(	1	5/31/2011	0.056	ppm	47	24	100	44201
49-047-20(	1	6/1/2011	0.055	ppm	47	24	100	44201
49-047-20(	1	6/2/2011	0.064	ppm	64	24	100	44201
49-047-20(	1	6/3/2011	0.061	ppm	54	24	100	44201
49-047-20(	1	6/4/2011	0.06	ppm	51	24	100	44201
49-047-20(	1	6/5/2011	0.045	ppm	38	22	92	44201
49-047-20(	1	6/6/2011	0.051	ppm	43	20	83	44201
49-047-20(	1	6/7/2011	0.05	ppm	42	24	100	44201
49-047-20(	1	6/8/2011	0.059	ppm	50	24	100	44201

49-047-200	1	6/9/2011	0.063	ppm	61	24	100	44201
49-047-200	1	6/10/2011	0.059	ppm	50	24	100	44201
49-047-200	1	6/11/2011	0.062	ppm	58	24	100	44201
49-047-200	1	6/12/2011	0.062	ppm	58	22	92	44201
49-047-200	1	6/13/2011	0.061	ppm	54	20	83	44201
49-047-200	1	6/14/2011	0.067	ppm	74	24	100	44201
49-047-200	1	6/15/2011	0.062	ppm	58	24	100	44201
49-047-200	1	6/16/2011	0.053	ppm	45	24	100	44201
49-047-200	1	6/17/2011	0.059	ppm	50	24	100	44201
49-047-200	1	6/18/2011	0.058	ppm	49	24	100	44201
49-047-200	1	6/19/2011	0.045	ppm	38	22	92	44201
49-047-200	1	6/20/2011	0.043	ppm	36	20	83	44201
49-047-200	1	6/22/2011	0.065	ppm	67	24	100	44201
49-047-200	1	6/23/2011	0.059	ppm	50	24	100	44201
49-047-200	1	6/24/2011	0.054	ppm	46	24	100	44201
49-047-200	1	6/25/2011	0.055	ppm	47	24	100	44201
49-047-200	1	6/26/2011	0.06	ppm	51	22	92	44201
49-047-200	1	6/27/2011	0.057	ppm	48	20	83	44201
49-047-200	1	6/28/2011	0.056	ppm	47	24	100	44201
49-047-200	1	6/29/2011	0.051	ppm	43	24	100	44201
49-047-200	1	6/30/2011	0.06	ppm	51	20	83	44201
49-047-200	1	1/1/2011	0.04	ppm	34	24	100	44201
49-047-200	1	1/2/2011	0.039	ppm	33	22	92	44201
49-047-200	1	1/3/2011	0.05	ppm	42	20	83	44201
49-047-200	1	1/4/2011	0.059	ppm	50	24	100	44201
49-047-200	1	1/5/2011	0.066	ppm	71	24	100	44201
49-047-200	1	1/6/2011	0.079	ppm	109	24	100	44201
49-047-200	1	1/7/2011	0.088	ppm	132	24	100	44201
49-047-200	1	1/8/2011	0.094	ppm	147	24	100	44201
49-047-200	1	1/9/2011	0.082	ppm	116	22	92	44201
49-047-200	1	1/10/2011	0.043	ppm	36	20	83	44201
49-047-200	1	1/11/2011	0.041	ppm	35	24	100	44201
49-047-200	1	1/12/2011	0.056	ppm	47	24	100	44201
49-047-200	1	1/13/2011	0.079	ppm	109	23	96	44201
49-047-200	1	1/15/2011	0.067	ppm	74	24	100	44201
49-047-200	1	1/16/2011	0.081	ppm	114	22	92	44201
49-047-200	1	1/17/2011	0.063	ppm	61	20	83	44201
49-047-200	1	1/18/2011	0.049	ppm	42	24	100	44201
49-047-200	1	1/19/2011	0.047	ppm	40	24	100	44201
49-047-200	1	1/20/2011	0.045	ppm	38	24	100	44201
49-047-200	1	1/21/2011	0.061	ppm	54	24	100	44201
49-047-200	1	1/22/2011	0.055	ppm	47	24	100	44201
49-047-200	1	1/24/2011	0.061	ppm	54	20	83	44201
49-047-200	1	1/25/2011	0.061	ppm	54	24	100	44201
49-047-200	1	1/26/2011	0.076	ppm	101	24	100	44201
49-047-200	1	1/27/2011	0.077	ppm	104	24	100	44201
49-047-200	1	1/28/2011	0.081	ppm	114	24	100	44201
49-047-200	1	1/29/2011	0.084	ppm	122	24	100	44201
49-047-200	1	1/30/2011	0.089	ppm	135	22	92	44201
49-047-200	1	1/31/2011	0.072	ppm	90	20	83	44201
49-047-200	1	2/1/2011	0.044	ppm	37	24	100	44201
49-047-200	1	2/2/2011	0.041	ppm	35	24	100	44201

49-047-20(	1	2/3/2011	0.045	ppm	38	24	100	44201
49-047-20(	1	2/4/2011	0.054	ppm	46	24	100	44201
49-047-20(	1	2/5/2011	0.06	ppm	51	24	100	44201
49-047-20(	1	2/6/2011	0.055	ppm	47	22	92	44201
49-047-20(	1	2/7/2011	0.057	ppm	48	20	83	44201
49-047-20(	1	2/8/2011	0.04	ppm	34	24	100	44201
49-047-20(	1	2/9/2011	0.048	ppm	41	24	100	44201
49-047-20(	1	2/10/2011	0.056	ppm	47	24	100	44201
49-047-20(	1	2/11/2011	0.072	ppm	90	24	100	44201
49-047-20(	1	2/12/2011	0.086	ppm	127	24	100	44201
49-047-20(	1	2/13/2011	0.1	ppm	161	22	92	44201
49-047-20(	1	2/14/2011	0.119	ppm	202	20	83	44201
49-047-20(	1	2/15/2011	0.108	ppm	182	9	38	44201
49-047-20(	1	2/16/2011	0.125	ppm	204	17	71	44201
49-047-20(	1	2/17/2011	0.054	ppm	46	24	100	44201
49-047-20(	1	2/18/2011	0.052	ppm	44	24	100	44201
49-047-20(	1	2/19/2011	0.07	ppm	84	24	100	44201
49-047-20(	1	2/20/2011	0.059	ppm	50	22	92	44201
49-047-20(	1	2/21/2011	0.065	ppm	67	20	83	44201
49-047-20(	1	2/22/2011	0.083	ppm	119	17	71	44201
49-047-20(	1	2/23/2011	0.085	ppm	124	24	100	44201
49-047-20(	1	2/24/2011	0.073	ppm	93	24	100	44201
49-047-20(	1	2/25/2011	0.06	ppm	51	24	100	44201
49-047-20(	1	2/26/2011	0.054	ppm	46	24	100	44201
49-047-20(	1	2/27/2011	0.062	ppm	58	22	92	44201
49-047-20(	1	2/28/2011	0.068	ppm	77	20	83	44201
49-047-20(	1	3/1/2011	0.092	ppm	142	24	100	44201
49-047-20(	1	3/2/2011	0.08	ppm	111	24	100	44201
49-047-20(	1	3/3/2011	0.077	ppm	104	24	100	44201
49-047-20(	1	3/4/2011	0.058	ppm	49	24	100	44201
49-047-20(	1	3/5/2011	0.055	ppm	47	24	100	44201
49-047-20(	1	3/6/2011	0.05	ppm	42	22	92	44201
49-047-20(	1	3/7/2011	0.052	ppm	44	20	83	44201
49-047-20(	1	3/8/2011	0.051	ppm	43	24	100	44201
49-047-20(	1	3/9/2011	0.051	ppm	43	24	100	44201
49-047-20(	1	3/10/2011	0.052	ppm	44	24	100	44201
49-047-20(	1	3/11/2011	0.051	ppm	43	24	100	44201
49-047-20(	1	3/12/2011	0.047	ppm	40	24	100	44201
49-047-20(	1	3/13/2011	0.054	ppm	46	22	92	44201
49-047-20(	1	3/14/2011	0.049	ppm	42	20	83	44201
49-047-20(	1	3/15/2011	0.049	ppm	42	24	100	44201
49-047-20(	1	3/16/2011	0.042	ppm	36	24	100	44201
49-047-20(	1	3/17/2011	0.047	ppm	40	24	100	44201
49-047-20(	1	3/18/2011	0.052	ppm	44	24	100	44201
49-047-20(	1	3/19/2011	0.051	ppm	43	24	100	44201
49-047-20(	1	3/20/2011	0.05	ppm	42	22	92	44201
49-047-20(	1	3/21/2011	0.05	ppm	42	20	83	44201
49-047-20(	1	3/23/2011	0.049	ppm	42	24	100	44201
49-047-20(	1	3/24/2011	0.053	ppm	45	24	100	44201
49-047-20(	1	3/25/2011	0.047	ppm	40	24	100	44201
49-047-20(	1	3/26/2011	0.048	ppm	41	24	100	44201
49-047-20(	1	3/27/2011	0.052	ppm	44	22	92	44201

49-047-200	1	3/28/2011	0.049	ppm	42	20	83	44201
49-047-200	1	3/29/2011	0.047	ppm	40	24	100	44201
49-047-200	1	3/30/2011	0.042	ppm	36	24	100	44201
49-047-200	1	3/31/2011	0.045	ppm	38	20	83	44201
49-047-200	1	4/1/2011	0.053	ppm	45	24	100	44201
49-047-200	1	4/2/2011	0.045	ppm	38	24	100	44201
49-047-200	1	4/3/2011	0.055	ppm	47	22	92	44201
49-047-200	1	4/4/2011	0.05	ppm	42	20	83	44201
49-047-200	1	4/5/2011	0.043	ppm	36	24	100	44201
49-047-200	1	4/6/2011	0.059	ppm	50	24	100	44201
49-047-200	1	4/7/2011	0.055	ppm	47	24	100	44201
49-047-200	1	4/8/2011	0.051	ppm	43	24	100	44201
49-047-200	1	4/9/2011	0.059	ppm	50	24	100	44201
49-047-200	1	4/10/2011	0.053	ppm	45	22	92	44201
49-047-200	1	4/11/2011	0.052	ppm	44	20	83	44201
49-047-200	1	4/12/2011	0.053	ppm	45	24	100	44201
49-047-200	1	4/13/2011	0.055	ppm	47	24	100	44201
49-047-200	1	4/14/2011	0.059	ppm	50	24	100	44201
49-047-200	1	4/15/2011	0.063	ppm	61	24	100	44201
49-047-200	1	4/16/2011	0.051	ppm	43	24	100	44201
49-047-200	1	4/17/2011	0.045	ppm	38	22	92	44201
49-047-200	1	4/18/2011	0.032	ppm	27	20	83	44201
49-047-200	1	4/19/2011	0.047	ppm	40	24	100	44201
49-047-200	1	4/20/2011	0.046	ppm	39	24	100	44201
49-047-200	1	4/21/2011	0.05	ppm	42	24	100	44201
49-047-200	1	4/22/2011	0.058	ppm	49	24	100	44201
49-047-200	1	4/23/2011	0.057	ppm	48	24	100	44201
49-047-200	1	4/24/2011	0.046	ppm	39	22	92	44201
49-047-200	1	4/25/2011	0.051	ppm	43	20	83	44201
49-047-200	1	4/26/2011	0.053	ppm	45	24	100	44201
49-047-200	1	4/27/2011	0.055	ppm	47	24	100	44201
49-047-200	1	4/28/2011	0.055	ppm	47	24	100	44201
49-047-200	1	4/29/2011	0.056	ppm	47	24	100	44201
49-047-200	1	4/30/2011	0.045	ppm	38	24	100	44201
49-047-200	1	5/1/2011	0.05	ppm	42	22	92	44201
49-047-200	1	5/2/2011	0.056	ppm	47	20	83	44201
49-047-200	1	5/3/2011	0.052	ppm	44	24	100	44201
49-047-200	1	5/5/2011	0.056	ppm	47	24	100	44201
49-047-200	1	5/6/2011	0.056	ppm	47	24	100	44201
49-047-200	1	5/7/2011	0.063	ppm	61	24	100	44201
49-047-200	1	5/8/2011	0.055	ppm	47	24	100	44201
49-047-200	1	5/9/2011	0.062	ppm	58	24	100	44201
49-047-200	1	5/10/2011	0.057	ppm	48	24	100	44201
49-047-200	1	5/11/2011	0.039	ppm	33	24	100	44201
49-047-200	1	5/12/2011	0.052	ppm	44	24	100	44201
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49-047-200	1	5/15/2011	0.044	ppm	37	24	100	44201
49-047-200	1	5/16/2011	0.05	ppm	42	24	100	44201
49-047-200	1	5/17/2011	0.051	ppm	43	24	100	44201
49-047-200	1	5/18/2011	0.053	ppm	45	24	100	44201
49-047-200								

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49-047-200	1	5/21/2011	0.052	ppm	44	24	100	44201
49-047-200	1	5/22/2011	0.048	ppm	41	24	100	44201
49-047-200	1	5/23/2011	0.057	ppm	48	23	96	44201
49-047-200	1	5/24/2011	0.051	ppm	43	24	100	44201
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49-047-200	1	5/26/2011	0.054	ppm	46	22	92	44201
49-047-200	1	5/27/2011	0.054	ppm	46	24	100	44201
49-047-200	1	5/28/2011	0.045	ppm	38	24	100	44201
49-047-200	1	5/29/2011	0.054	ppm	46	24	100	44201
49-047-200	1	5/30/2011	0.057	ppm	48	24	100	44201
49-047-200	1	5/31/2011	0.053	ppm	45	24	100	44201
49-047-200	1	6/1/2011	0.051	ppm	43	24	100	44201
49-047-200	1	6/2/2011	0.062	ppm	58	24	100	44201
49-047-200	1	6/3/2011	0.06	ppm	51	24	100	44201
49-047-200	1	6/4/2011	0.058	ppm	49	24	100	44201
49-047-200	1	6/5/2011	0.041	ppm	35	22	92	44201
49-047-200	1	6/6/2011	0.052	ppm	44	20	83	44201
49-047-200	1	6/7/2011	0.049	ppm	42	24	100	44201
49-047-200	1	6/8/2011	0.056	ppm	47	24	100	44201
49-047-200	1	6/9/2011	0.06	ppm	51	24	100	44201
49-047-200	1	6/10/2011	0.059	ppm	50	24	100	44201
49-047-200	1	6/11/2011	0.06	ppm	51	24	100	44201
49-047-200	1	6/12/2011	0.06	ppm	51	22	92	44201
49-047-200	1	6/13/2011	0.06	ppm	51	20	83	44201
49-047-200	1	6/14/2011	0.063	ppm	61	24	100	44201
49-047-200	1	6/15/2011	0.06	ppm	51	24	100	44201
49-047-200	1	6/16/2011	0.05	ppm	42	24	100	44201
49-047-200	1	6/17/2011	0.057	ppm	48	23	96	44201
49-047-200	1	6/18/2011	0.058	ppm	49	24	100	44201
49-047-200	1	6/19/2011	0.047	ppm	40	22	92	44201
49-047-200	1	6/21/2011	0.06	ppm	51	24	100	44201
49-047-200	1	6/22/2011	0.07	ppm	84	24	100	44201
49-047-200	1	6/23/2011	0.059	ppm	50	24	100	44201
49-047-200	1	6/24/2011	0.053	ppm	45	24	100	44201
49-047-200	1	6/25/2011	0.056	ppm	47	24	100	44201
49-047-200	1	6/26/2011	0.06	ppm	51	22	92	44201
49-047-200	1	6/27/2011	0.058	ppm	49	20	83	44201
49-047-200	1	6/28/2011	0.056	ppm	47	24	100	44201
49-047-200	1	6/29/2011	0.052	ppm	44	24	100	44201
49-047-200								

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				Not in a MS				

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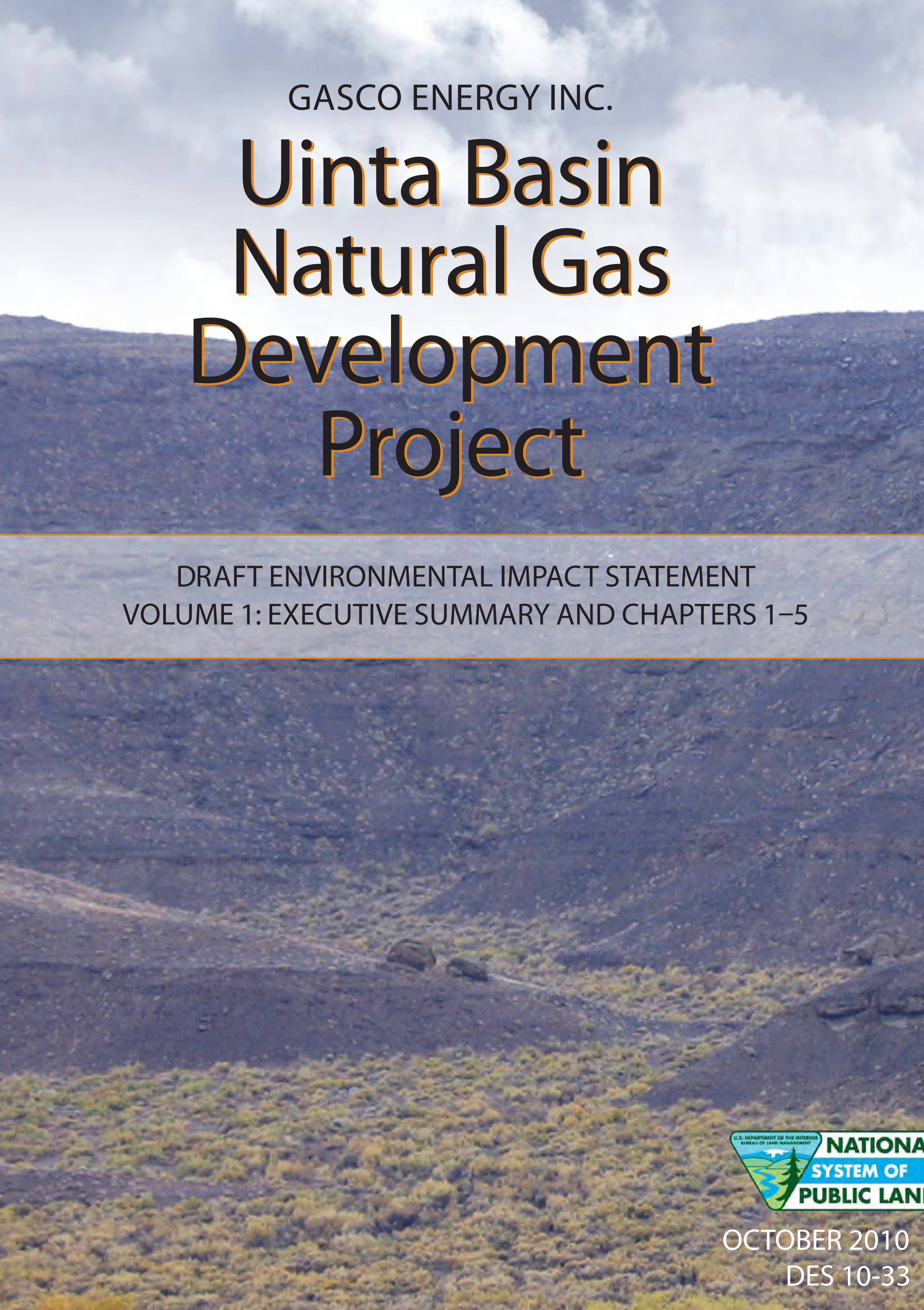


GASCO ENERGY INC.

Uinta Basin Natural Gas Development Project

DRAFT ENVIRONMENTAL IMPACT STATEMENT

VOLUME 1: EXECUTIVE SUMMARY AND CHAPTERS 1–5

BLM

Vernal Field Office

U.S. DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

NATIONAL SYSTEM OF PUBLIC LANDS

OCTOBER 2010

DES 10-33

The next best method for estimating existing air quality is based on air monitoring conducted that, while not meeting the standards described above, is still considered of sufficient quality to be used for modeling and initial or screening air quality determinations. Reasons for monitoring not meeting NAAQS CFR standards, but still be sufficient for other purposes, might include use of non-FRM certified monitors, not meeting all CFR standards for the monitoring site, or operating otherwise compliant monitors less than the averaging time of the applicable pollutant standard (e.g., less than three years for ozone). Air monitoring data over ten years old are generally considered to be out of date, though they still may be representative if emission sources in the area have not changed much. Given these qualifiers, there has been relevant air monitoring conducted recently in the Uinta Basin for $PM_{2.5}$ and ozone.

3.2.3.1.5.1 $PM_{2.5}$ Air Monitoring

Starting in December 2006 and running through December 2007, the Utah Department of Environmental Quality (UDAQ) conducted air monitoring for $PM_{2.5}$ in the town of Vernal, Uintah County. Over the winter, $PM_{2.5}$ levels were measured at the Vernal monitoring station that were higher than the new $PM_{2.5}$ NAAQS that became effective in December 2006. The maximum 24-hour average concentration over this period was 63.3 ug/m^3. Additional $PM_{2.5}$ monitoring was conducted by UDAQ in Vernal in 2008 and in Vernal and Roosevelt (Duchesne County) in 2009, which also monitored maximum 24-hour values above the NAAQS during the winter months. $PM_{2.5}$ monitoring conducted by UDAQ during the summer of 2007 did not find any elevated concentrations. A limited analysis of the filters used to collect the $PM_{2.5}$ samples was conducted to chemically speciate the particulate samples. This analysis found that the composition was primarily carbon-based. In the case of Teflon filters, the composition was unidentifiable, which in a Teflon filter is typically indicative of also being carbonaceous because these types of filters cannot be used to detect carbon-based particulate.

Beginning in the summer of 2009, $PM_{2.5}$ monitoring is being conducted in the Ouray and Redwash areas of Uintah County. This monitoring is being conducted to comply with an EPA consent order. It is located in a rural area contingent with oil and gas operations and removed from urban sources. No exceedences of the $PM_{2.5}$ 24-hour standard have been observed.

The sources of elevated $PM_{2.5}$ concentrations during winter inversions in Vernal and Roosevelt have not been conclusively identified yet. Based on experiences and studies in other areas of the Rocky Mountain west and the emission inventory in the Uinta Basin, potential sources can be tentatively identified. In Utah, elevated $PM_{2.5}$ concentrations along the Wasatch Front are associated with secondarily formed particles from sulfates, nitrates, and organic chemicals from a variety of sources (UDAQ 2006). In Cache Valley, approximately half of ambient $PM_{2.5}$ during elevated concentrations is composed of ammonium nitrate, most likely from agricultural operations. The other half is from combustion, primarily mobile sources and woodstoves (Martin 2006). For comparison, $PM_{2.5}$ in most rural areas in the western United States is typically dominated by total carbonaceous mass and crustal materials from combustion activities and fugitive dust, respectively (EPA 2009). Because the Uinta Basin is not a major metropolitan area (like those found on the Wasatch Front) nor does it have significant agricultural activities (like those found in Cache Valley), the most likely causes of elevated $PM_{2.5}$ at the Vernal monitoring station are probably those common to other areas of the western US (combustion and dust). The filter speciation that has been done to date tends to support this conclusion because the dominant chemical species from the filters is carbonaceous mass, which is indicative of wood burning, diesel emissions, or both. It is unlikely that significant transport of $PM_{2.5}$ precursors are occurring during the intense winter inversions under which these elevated $PM_{2.5}$ levels are forming, and as there is extensive snow cover during these episodes fugitive dust is also an unlikely significant contributor.

The complete UDAQ $PM_{2.5}$ monitoring data can be found at http://www.airmonitoring.utah.gov/dataarchive/archpm25.htm

3.2.3.1.5.2 Ozone Air Monitoring

Active ozone monitoring in the Uinta Basin began in the summer of 2009 at the Ouray and Redwash monitoring sites (the ozone monitors are collocated with the $PM_{2.5}$ monitors). Both sites have recorded numerous exceedences of the 8-hour ozone standard during the winter months (January through March). The maximum 8-hour average recorded to date is 0.123 ppm, well above the current ozone NAAQS of 0.075 ppm. These data have recently been released by EPA. Although the monitors are not currently being operated to CFR standards, and are not considered adequate data to make a NAAQS determination, the data are considered viable and representative of the area. Apparently, high concentrations of ozone are being formed under a “cold pool” process, whereby stagnate air conditions with very low mixing heights form under clear skies with snow-covered ground and abundant sunlight that, combined with area precursor emissions (NO_x and VOCs), create intense episodes of ozone. Based on the first year of monitoring, these episodes occur only during the winter months (January through March). This phenomenon has also been observed in similar types of locations in Wyoming, and has contributed to a proposed nonattainment designation for Sublette County.

The National Park Service also operates an ozone monitor in Dinosaur National Monument during the summer months. No exceedences of the current ozone NAAQS have been recorded at this site.

Winter ozone formation is a newly recognized issue, and the methods of analyzing and managing this problem are still in development. Existing photochemical models are currently unable to replicate winter ozone formation satisfactorily, in part due to the very low mixing heights associated with the unique meteorology of these ambient conditions.

Based on the emission inventories developed for Uintah County, the likely dominant source of ozone precursors at the Ouray and Redwash monitoring sites are oil and gas operations near the monitors. The monitors are located in remote areas where impacts from other human activities are unlikely to be significantly contributing to this ozone formation. Although ozone precursors can be transported large distances, the meteorological conditions under which this cold pool ozone formation is occurring tend to preclude any significant transport. Currently, ozone exceedences in this area are confined to the winter months during periods of intense surface inversions and low mixing heights. Significant work remains to definitively identify the sources of ozone precursors contributing to the observed ozone concentrations. Speciation of gaseous air samples collected during periods of high ozone is needed to determine which VOCs are present and what their likely sources are.

The complete EPA Ouray and Redwash monitoring data can be found here: http://www.epa.gov/airexplorer/index.htm

4.2 AIR QUALITY

Air quality impacts were evaluated for both near-field and far-field impacts. Near-field impacts quantify the direct and indirect local impacts created by each alternative, while far-field impacts describe the potential impacts at locations a significant distance away from the project area.

4.2.1 NEAR-FIELD AIR QUALITY

The near-field analysis considered potential impacts to air quality that may occur within 3 miles (5 km) of the project area. The Near-Field Air Quality Technical Support Document (Buys & Associates 2008b and Appendix H) presents a complete description of the project emissions, the modeling protocol, and modeling results. There are two types of activities associated with each alternative that were evaluated for impacts to air quality; development and operations. Development includes: the construction of individual well pads and associated access roads, drilling, and completion activities. Operations include the running of equipment associated with production and the associated truck traffic.

Dispersion modeling was performed for all alternatives to evaluate both development and operational impacts. The AERMOD model (version 07026) was used to predict the impacts of pollutant emissions for comparison to the NAAQS for CO, SO_2, PM_{10}, and $PM_{2.5}$. Because development activities are temporary and short-term in nature, comparisons to PSD increments are not appropriate. AERMOD was used to predict impacts of NO_x emissions as a surrogate for NO_2. The meteorological data used were from surface and upper air stations developed for the *West Tavaputs Environmental Impact Statement* (BLM 2008d). Additional details about the modeling are in the Near-Field Air Quality Technical Support Document (Buys & Associates 2008b and Appendix H).

4.2.1.1 DEVELOPMENT

Near-field impacts from development activities are predominantly short-term and localized to the nearby area. Pollutant emissions from development activities include the following sources:

- Well pad and road construction: equipment producing fugitive dust while moving and leveling earth;
- Drilling: vehicles generating fugitive dust on access roads, and drill rig engine exhaust;
- Completion: vehicles generating fugitive dust on access roads, frac pump engine and generator emissions, and completion venting emissions;
- Vehicle tailpipe emissions associated with all development phases;

Pollutant emissions generated from development sources are summarized in Table 4-2.

Table 4-2. Annual Well Development Emissions for Each Alternative

Pollutant	Well Development Emissions (tons/year)				
	Alternative A (Proposed Action)	Alternative B (Reduced)	Alternative C (Full)	Alternative D (No Action)	Alternative E (Directional)
Criteria Pollutants & VOC					
NO_x	1,298	1,027	1,357	511	1,762
CO	421	332	444	167	522
VOC	103	81.5	113	42.6	116
SO_2	23.2	18.3	23.9	9.01	30.8
PM_{10}	4,079	3,228	4,486	1,700	3,641
$PM_{2.5}$	433	343	476	180	395
Hazardous Air Pollutants					
Benzene	0.62	0.49	0.69	0.26	0.66
Toluene	1.06	0.84	1.17	0.44	1.08
Ethylbenzene	0.04	0.03	0.04	0.02	0.04
Xylene	0.55	0.44	0.61	0.23	0.56
n-Hexane	1.21	0.96	1.33	0.50	1.21
Formaldehyde	0.44	0.35	0.48	0.18	0.14
Acetaldehyde	3.34×10^{-03}	2.64×10^{-03}	3.67×10^{-03}	1.38×10^{-03}	4.62×10^{-03}
Acrolein	1.04×10^{-03}	8.23×10^{-04}	1.14×10^{-03}	4.31×10^{-04}	1.44×10^{-03}
1,3-Butadiene	1.34×10^{-06}	1.06×10^{-06}	1.48×10^{-06}	5.60×10^{-07}	1.34×10^{-06}
Naphthalene	0.02	0.01	0.02	0.01	0.02
Total HAPs	4.14	3.25	4.51	1.71	3.80
Greenhouse Gases					
CO_2	63,870	50,564	70,257	26,473	86,970
CH_4	517	409	568	215	530

4.2.1.1.1 Development Impacts

Table 4-3 shows all pollutants modeled for development for the Proposed Action compared to the NAAQS. The maximum modeled concentration for NO_2 reflects an adjustment by a factor of 0.75, in accordance with standard EPA methodology (60:153 FR 40469, Aug 9, 1995) to convert from the modeled NO_x annual concentration to a NO_2 annual concentration. The modeling showed that no exceedances of NAAQS would be predicted for all development activities. The annual results demonstrate that even if these activities lasted for an entire year in the same location, the effects would be less than all applicable standards.

Table 4-19. Carcinogenic HAP MEI Risk for Each Alternative

Hazardous Air Pollutant	Cancer Risk				
	Alternative A (Proposed Action)	Alternative B (Reduced)	Alternative C (Full)	Alternative D (No Action)	Alternative E (Directional)
Dichlorobenzene	4.2×10^{-10}	3.5×10^{-10}	5.0×10^{-10}	7.1×10^{-11}	2.8×10^{-10}
Ethylene Dibromide	4.8×10^{-07}	3.4×10^{-07}	5.5×10^{-07}	1.4×10^{-07}	3.4×10^{-07}
Methylene Chloride	1.7×10^{-10}	1.2×10^{-10}	1.9×10^{-10}	4.8×10^{-11}	1.2×10^{-10}
Naphthalene	3.6×10^{-08}	3.4×10^{-08}	5.6×10^{-08}	1.1×10^{-08}	3.4×10^{-08}
Vinyl Chloride	2.4×10^{-10}	1.7×10^{-10}	2.7×10^{-10}	6.7×10^{-11}	1.7×10^{-10}
Benzo(b)fluoranthene[a]	3.3×10^{-10}	2.3×10^{-10}	3.8×10^{-10}	9.4×10^{-11}	2.3×10^{-10}
Chrysene[a]	1.4×10^{-10}	9.8×10^{-11}	1.6×10^{-10}	3.9×10^{-11}	2.3×10^{-11}
TOTAL MEI RISK	$\mathbf{5.9 \times 10^{-06}}$	$\mathbf{4.3 \times 10^{-06}}$	$\mathbf{6.9 \times 10^{-06}}$	$\mathbf{1.7 \times 10^{-06}}$	$\mathbf{5.0 \times 10^{-06}}$

[a] Pollutant is a HAP because it is polycyclic organic matter (POM).

4.2.1.2.4 Summary of Operations Impacts

Implementation of the Proposed Action or Alternatives would cause increases in criteria pollutants. Potential modeled impacts for Alternative C are predicted to exceed the NAAQS for PM_{10}. Potential modeled impacts for Alternatives A, B, C, and E exceed the PSD Class II increment for PM_{10}. The distribution of concentration contours indicates that the source of the maximum PM_{10} concentrations is road traffic (see Figure 4-1). Predicted concentration contours are similar for PM_{10} and $PM_{2.5}$; the Near-Field Air Quality Technical Support Document (Buys & Associates 2008b and Appendix H) includes figures of $PM_{2.5}$ contours for each alternative showing the maximum concentrations are the result of truck traffic. Therefore none of the alternatives exceed PSD Class II increments (PSD increments do not apply to mobile sources).

Implementation of the Proposed Action or Alternatives would cause increases in HAP concentrations. The increased potential concentration would be long term, lasting the life of the project (LOP; 45 years). None of the alternatives would exceed the Utah TSLs. Potential impacts for all alternatives exceed the REL for acrolein. Alternatives A, B, C, and E are predicted to exceed the RfC for acrolein. Predicted concentrations for all alternatives are below the acute exposure guideline level for acrolein. Predicted concentrations for all alternatives are below the California EPA chronic REL (similar to the RfC) for acrolein. Minor increases in cancer risk are predicted to occur for all alternatives. However, the predicted incremental cancer risks would occur only within relatively small areas. The following tables (Tables 4-20 through 4-24) summarize the operational impacts for each alternative after full field development.

Table 4-20. Summary of Near-Field Operation Maximum Impacts

Pollutant and Averaging Period	Averaging Period	Percent of NAAQS (Project + Background)				
		Alternative A (Proposed Action)	Alternative B (Reduced)	Alternative C (Full)	Alternative D No Action)	Alternative E (Directional)
NO_2	Annual	19.3%	17.9%	18.8%	18.0%	18.7%
PM_{10}	24-hour	99.7%	86.6%	112%	56.1%	87.0%
$PM_{2.5}$	Annual	68.7	88.7%	90.7%	76.7%	88.7%
	24-hour	66.0%	60.9%	70.3%	48.6%	61.1%
CO	1-hour	3.33%	3.07%	3.30%	2.94%	3.07%
	8-hour	12.0%	11.5%	11.8%	11.4%	11.7%

Table 4-21. Summary of Near-Field Operation Maximum Impacts to PSD Class II Increments

Pollutant and Averaging Period	Averaging Period	Percent of PSD Class II Increment				
		Alternative A (Proposed Action)	Alternative B (Reduced)	Alternative C (Full)	Alternative D (No Action)	Alternative E (Directional)
NO_2	Annual	9.12%	3.78%	7.20%	3.90%	3.78%
PM_{10}	24-hour	287%	222%	357%	69%	222%

Table 4-22. Summary of HAP REL Operation Impacts for Each Alternative

HAP	REL	Percent of REL				
	($\mu g/m^3$)	Alternative A (Proposed Action)	Alternative B (Reduced)	Alternative C (Full)	Alternative D (No Action)	Alternative E (Directional)
Acrolein	0.19[a]	1,189%	868%	1,479%	289%	868%
	69[b]	3.28%	2.39%	4.07%	0.80%	2.39%
	230[c]	0.98%	0.72%	1.22%	0.24%	0.72%
	450[d]	0.50%	0.37%	0.62%	0.12%	0.37%
Formaldehyde	94[a]	24.8%	18.0%	30.7%	6.00%	18.0%
Acetaldehyde	81000[b]	0.01%	0.01%	0.02%	<0.01%	0.01%
Benzene	1,300[a,e]	0.86%	0.62%	0.83%	0.21%	0.62%
	160,000[d]	0.02%	0.01%	0.01%	<0.01%	0.01%
Toluene	37,000[a]	0.19%	0.12%	0.18%	0.04%	0.12%
Ethylbenzene	350,000[d]	<0.01%	<0.01%	<0.01%	<0.01%	<0.01%
Xylenes	22,000[a]	0.32%	0.20%	0.31%	0.07%	0.20%

Ozone Impact Assessment

for

GASCO Energy Inc.
Uinta Basin Natural Gas Development Project
Environmental Impact Statement

Prepared for: Bureau of Land Management
Vernal Field Office
Vernal, Utah

Prepared by: Alpine Geophysics, LLC
Arvada, CO
Dennis McNally
Cyndi Loomis

and

Buys and Associates Environmental Consultants
Littleton, CO
Daniel Pring
Doug Henderer

April 2010

1.0 Introduction

Gasco Production Company (Gasco) has proposed to the United States Department of the Interior (USDOI) Bureau of Land Management (BLM) Vernal Field Office (VFO) to develop oil and natural gas resources within the Monument Butte, Red Wash and West Tavaputs Exploration and Development Areas. The project area is located within Uintah and Duchesne Counties, Utah and consists of approximately 187 sections located in Township 9 South, Ranges 18 and 19 East; Township 10 South, Ranges 14, 15, 16, 17 and 18 East; and Township 11 South, Ranges 14, 15, 16, 17, 18 and 19 East (Map 1).

Gasco operates the majority of the mineral lease rights underlying both the public and private lands in the project area. The project area encompasses approximately 206,826 acres predominantly in the West Tavaputs Exploration and Development Area with some overlap into the Monument Butte–Red Wash Exploration and Development Area of the Diamond Mountain Planning Area of the VFO. The project area includes lands within the restored exterior boundary of the Ute Indian Reservation, but no lands administered by the Tribe or by the Bureau of Indian Affairs. Targeted geologic strata lie in the Wasatch, Mesaverde, Blackhawk, Mancos, Dakota, and Green River formations, approximately 5,000–20,000 feet below the earth's surface.

1.1 Project Description

The Gasco Energy Inc. Uinta Basin Natural Gas Development Project (GASCO) Project Area is located 20 miles south-southwest of Roosevelt, Utah and covers 206,826 acres in an existing oil and gas producing region located in Duchesne and Uintah Counties, Utah. Surface ownership in the project area is 86% federal (managed by the Bureau of Land Management [BLM]), 12% State of Utah (managed by State of Utah School and Institutional Trust Lands Administration [SITLA]), and 2% private.

The GASCO Project Area currently contains active producing wells, with accompanying production related facilities, roads, and pipelines. Additional wells are proposed for development and are being considered under the Wilkin Ridge Environmental assessment (UT-080-2006-478).

Proposed wells would be drilled to recover gas reserves from the Wasatch, Mesa Verde, Blackhawk, Mancos, Dakota, and Green River Formations in the GASCO Project Area. The spacing of the wells will vary according to the geologic characteristics of the formation being developed; the densest spacing expected is one well pad per 40 acres.

The primary components of the Proposed Action that were utilized for the development of a project specific emissions inventory for this ozone assessment were based upon an updated development schedule developed by Gasco in April 2010. The Proposed Action primary components are as follows:

Up to 1,491 natural gas wells over a 15 year development period, 45 year life of project (LOP);

Up to 10 drilling rigs operating year round;

30 evaporative ponds with a total of 2,700-hp of electrical generation; and

Approximately 21,325 horsepower of compression would be added to the existing system, for a total of 27,940 horsepower (hp) within the Project Area.

Table 1-1 shows the summary of the emissions inventory for the Proposed Action.

Under the Proposed Action, the rate of development for new wells would increase gradually from project initiation until the year 2015 when the maximum proposed development rate is projected to be realized. It is anticipated that the maximum development rate of 120 new wells per year would be sustained between the years 2015 and 2018. After 2018 the planned rate of development is projected to decrease until full project development is accomplished in about the year 2015.

Emissions to the atmosphere from the proposed project would include the following criteria pollutants and precursors: nitrogen oxides (NO_x), particulates (PM_{10} and $PM_{2.5}$), Volatile Organic Compounds (VOC), and sulfur dioxide (SO_2). These pollutants would be emitted from the following activities and sources:

Well pad and road construction: equipment producing fugitive dust while moving and leveling earth, vehicles generating fugitive dust on access roads;

Drilling: vehicles generating fugitive dust on access roads, and drill rig engine exhaust;

Completion: vehicles generating fugitive dust on access roads, frac pump engine and generator emissions, and completion venting emissions;

Vehicle tailpipe emissions associated with all development phases;

Well production operations: three-phase separator emissions, flashing and breathing emissions from a condensate tank, fugitive dust and tailpipe emissions from pumpers and trucks transporting produced condensate and water from storage tanks;

Central production facility: compressor engines emissions, central glycol dehydration unit emissions, flare emissions for control of central facility VOC emissions, central flashing and breathing emissions from condensate tanks, and emissions associated with loading natural gas liquids (NGL) into trucks; and

Water Evaporation Facility: generator engine emissions and fugitive dust and tailpipe emissions from water trucks delivering produced water.

To reduce the emission of ozone forming precursors (NO_X and VOC) GASCO has committed to implement the following Applicant Committed Environmental Protection Measures (ACEPMs):

1. The use of Tier II or better diesel drill rig engines to reduce NO_X emissions;
2. RMP compliant NO_X emission limitations of 1.0 g/hp-hr for engines rated greater than 300 hp and 2.0 g/hp-hr for engines rated at 300 hp or less.
3. The installation of low-bleed pneumatic controls, where technically feasible, on all new separators to reduce potential VOC emissions;
4. To reduce current VOC emissions all existing high-bleed pneumatic controls within the project area will be replaced or retrofitted with low-bleed units where technical feasible;
5. The use of solar-powered chemical pumps (i.e. Methanol pumps) in place of VOC emitting pneumatic pumps at new facilities;

6. The use of centralized compression facilities (no well site compression) to minimize potential NO_X emissions;
7. The use of centralized dehydration, (no well site dehydration) to minimize potential VOC emissions;
8. The control of central facility stock tanks and glycol dehydrators to reduce potential VOC emissions by at least 95%.

The above ACEPMs would result in the reduction of 647 tons per year NO_X and 8,273 tons per year of VOC assuming the implementation of the Proposed Action. Larger or smaller emission reductions would occur as a result of the ACEPMs if other alternatives other than the Proposed Action were to be implemented.

This ozone impact analysis considered the emissions from the Proposed Action with and without applicant committed measures to reduce ozone precursor emissions.

Oil and Gas Exploration and Production Emission Sources

Presentation for the

Air Quality Control Commission Retreat

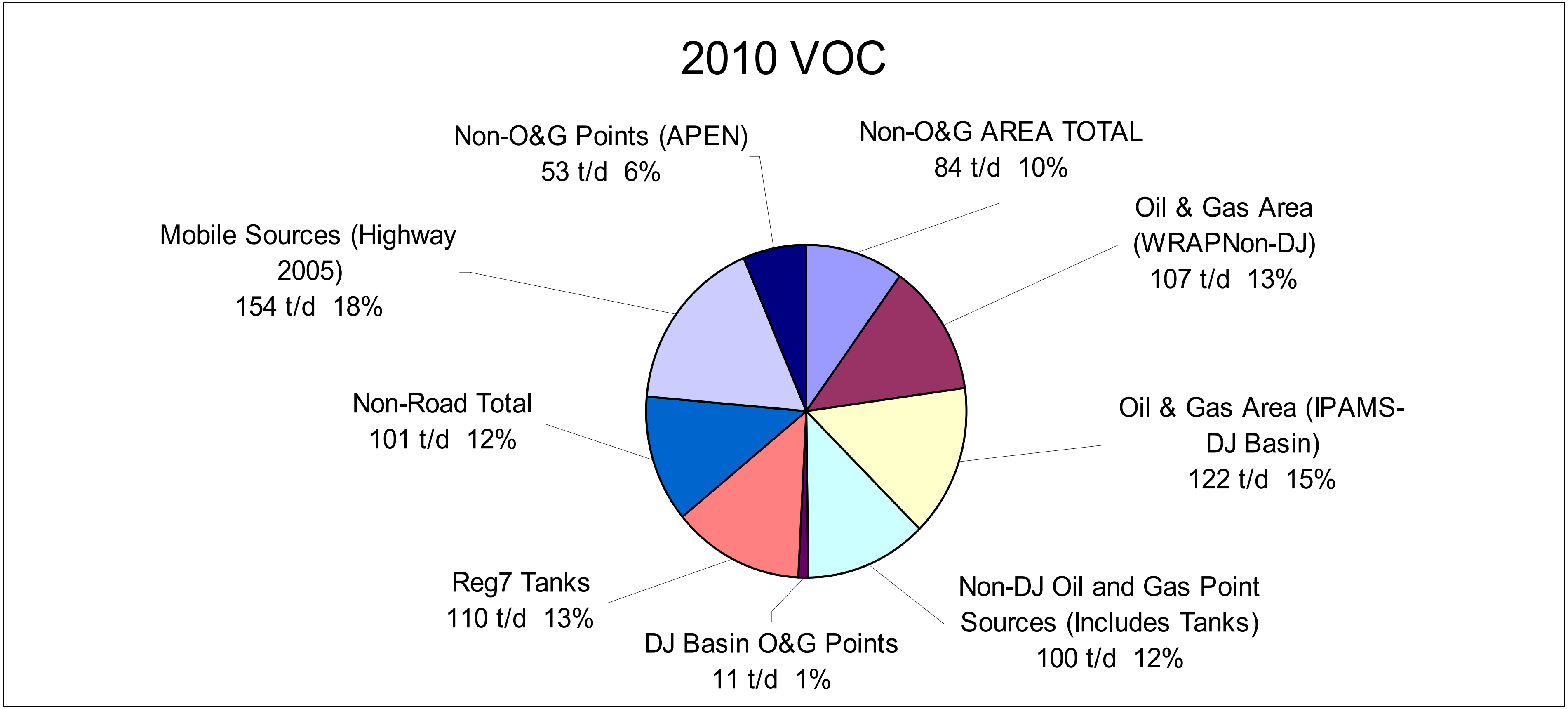
May 15, 2008

Air Pollution Control Division

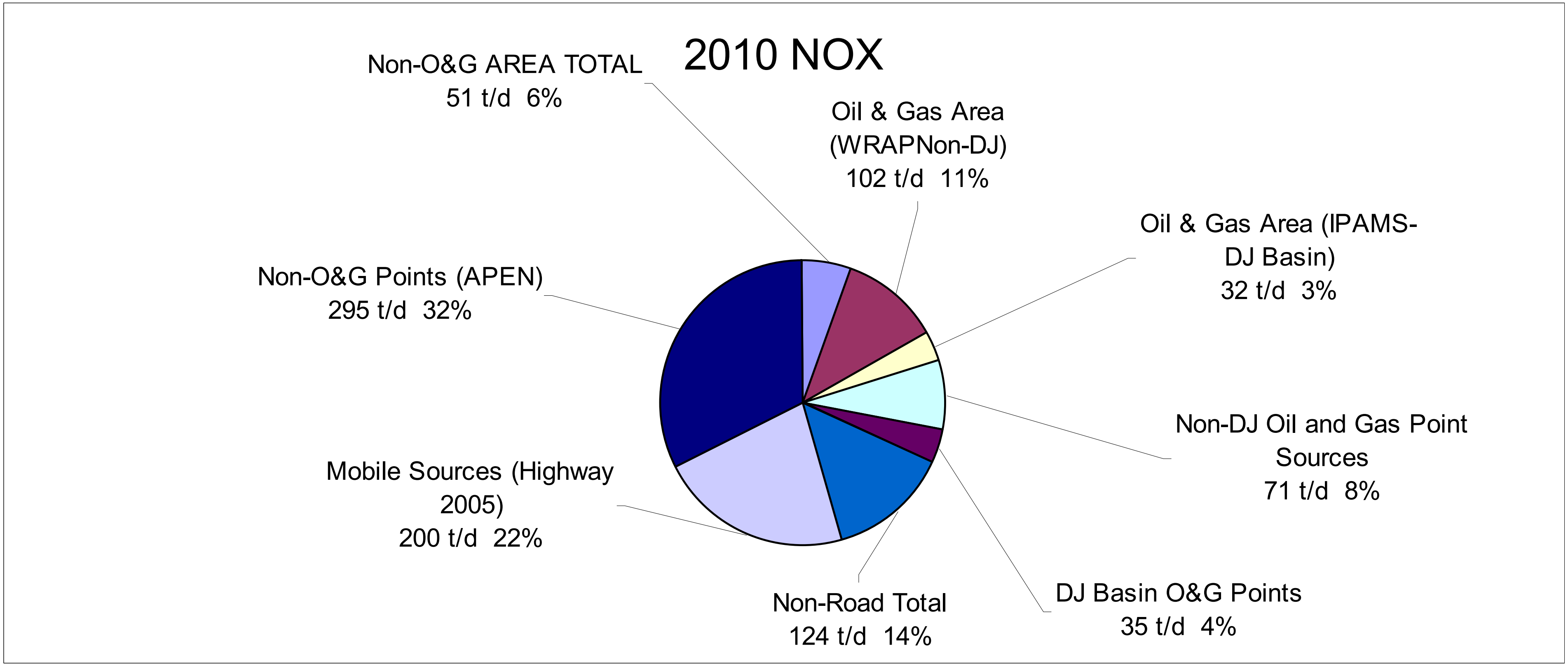
Approach to Statewide Oil and Gas Control Strategy Development

- Oil and gas is the largest VOC source category on the State
- Oil and gas development is rapid and projected to significantly expand – especially in western Colorado
- Strategies are being developed to control the growth in VOC and NOx emissions from O&G
  - Pre-emptive – “keep clean areas clean”
  - Help prevent ozone nonattainment
  - Improve visibility

Statewide VOC Emissions – 2010
(4% increase since 2006)



Statewide
NOx Emissions – 2010
(8% increase since 2006)



Approach to Statewide Oil and Gas Control Strategy Development

- All current regulatory programs remain in place
- Categorical Exemptions - Eliminate for Significant Oil and Gas Categories - New Sources (VOCs)
- Pneumatics – New, Modified (VOCs)
- Condensate Tanks – New, Modified (VOCs)
- Drill Rigs – New and Existing (NOx, PM)
- Existing Engines – Retrofit (VOCs, CO, NOx

Elimination of Categorical Exemptions for Oil and Gas Sources

- Crude oil truck loading equipment
- Oil/gas production wastewater tanks
- Stationary Internal Combustion Engines meeting horsepower and hours of operation restrictions
- Condensate tanks with production 730 BBL/year or less
- Fuel burning equipment (includes heater treaters, separators, and dehydrator reboilers)
- Petroleum industry flares less than 5 tons per year (tpy) emissions
- Storage of butane, propane, LPG
- Crude oil storage tanks
- Surface water storage impoundment
- Internal combustion engines on drill rigs
- Venting of natural gas lines for safety purposes (for APEN purposes only)
- Oil and gas production activities including: well drilling, workovers and completions (for APEN purposes only)

CONSERVATION COMMISSION

COLORADO

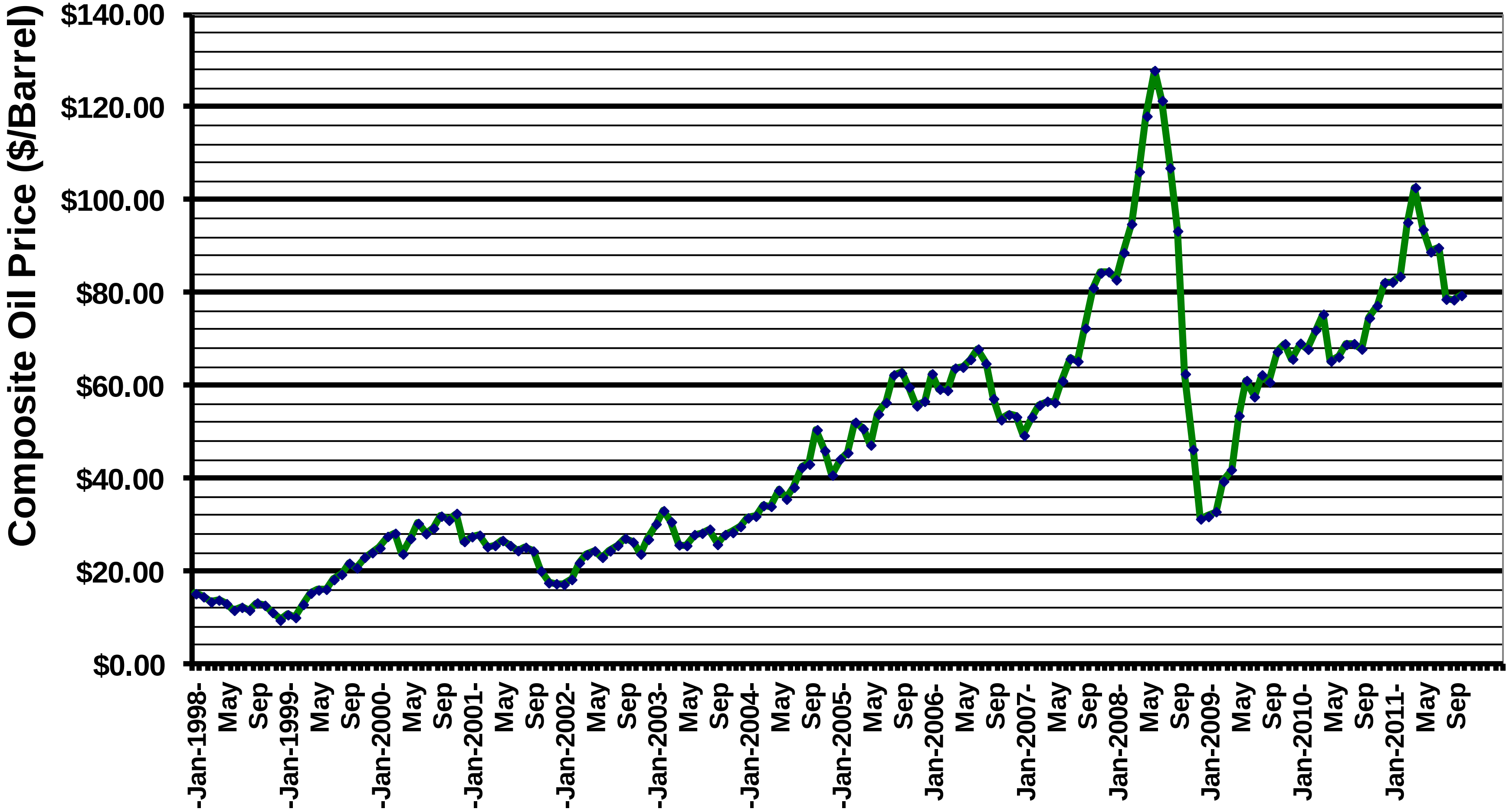
WEEKLY & MONTHLY

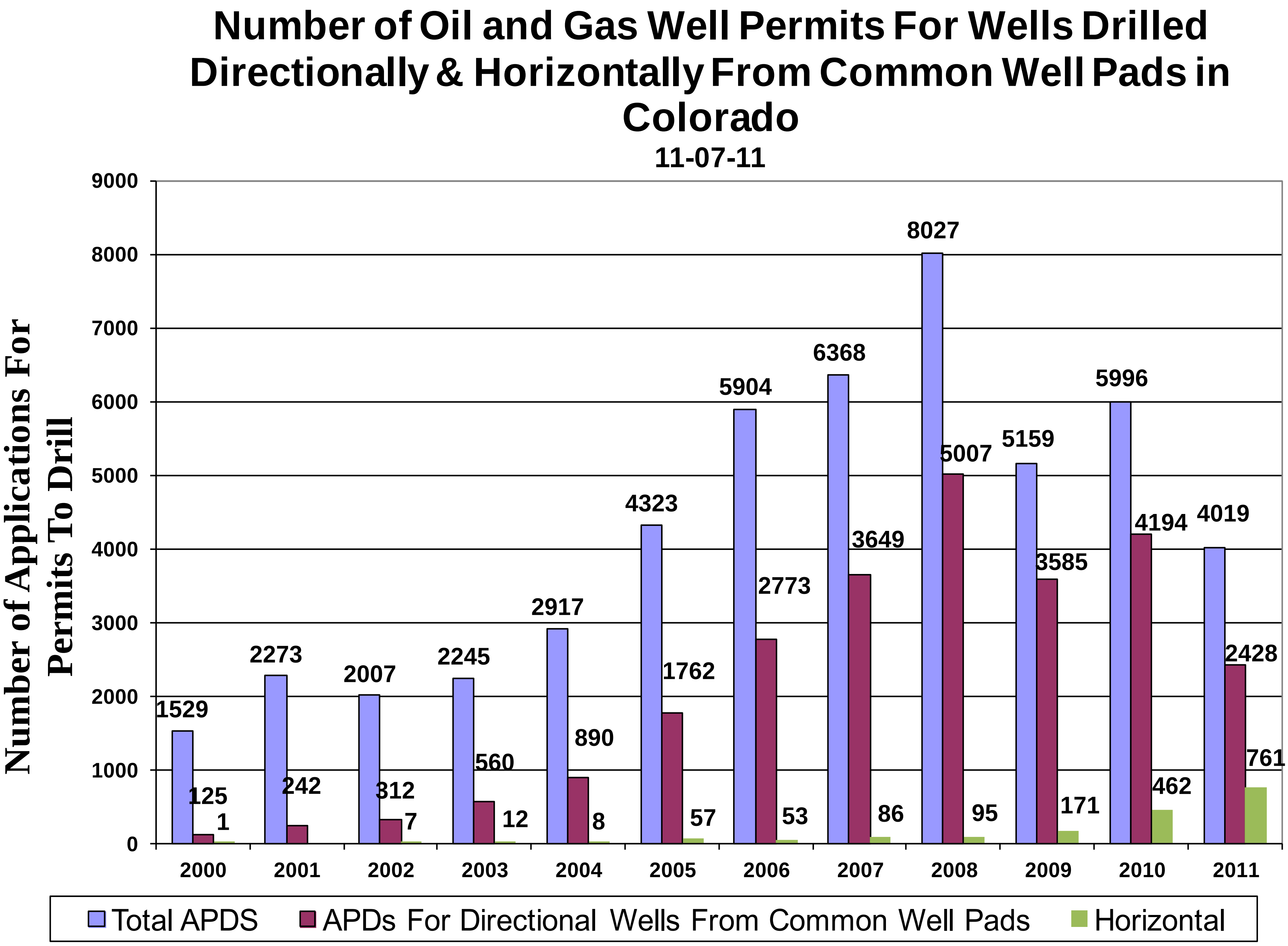
OIL & GAS STATISTICS

11-07-11 – visit our website: www.colorado.gov/cogcc

Colorado Monthly Composite Oil Price

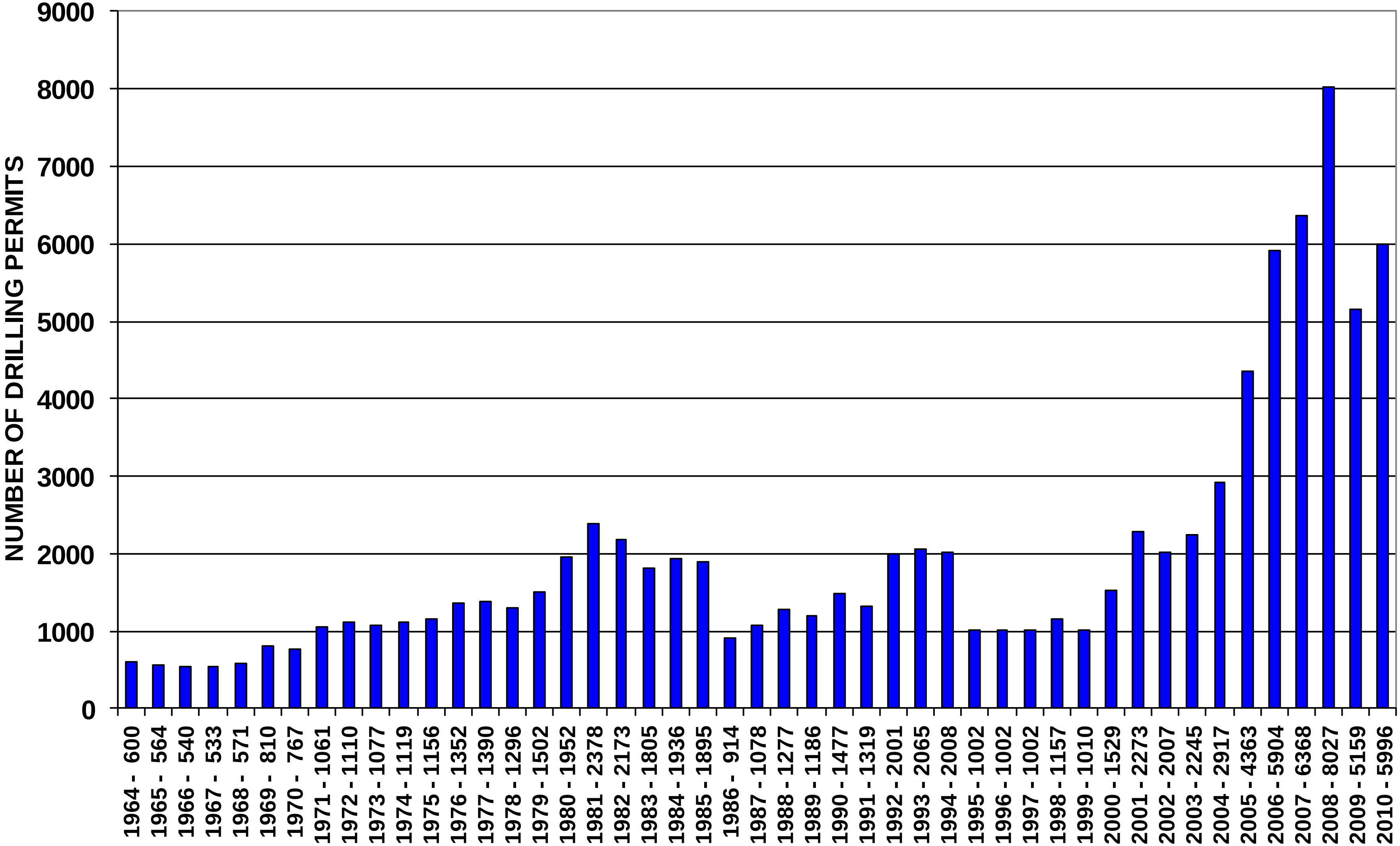
(35% Chevron NW, 5% Equiva SW, 40% Valero NE, 20% Valero SE : ~= WTI+$0.70) 11-07-11





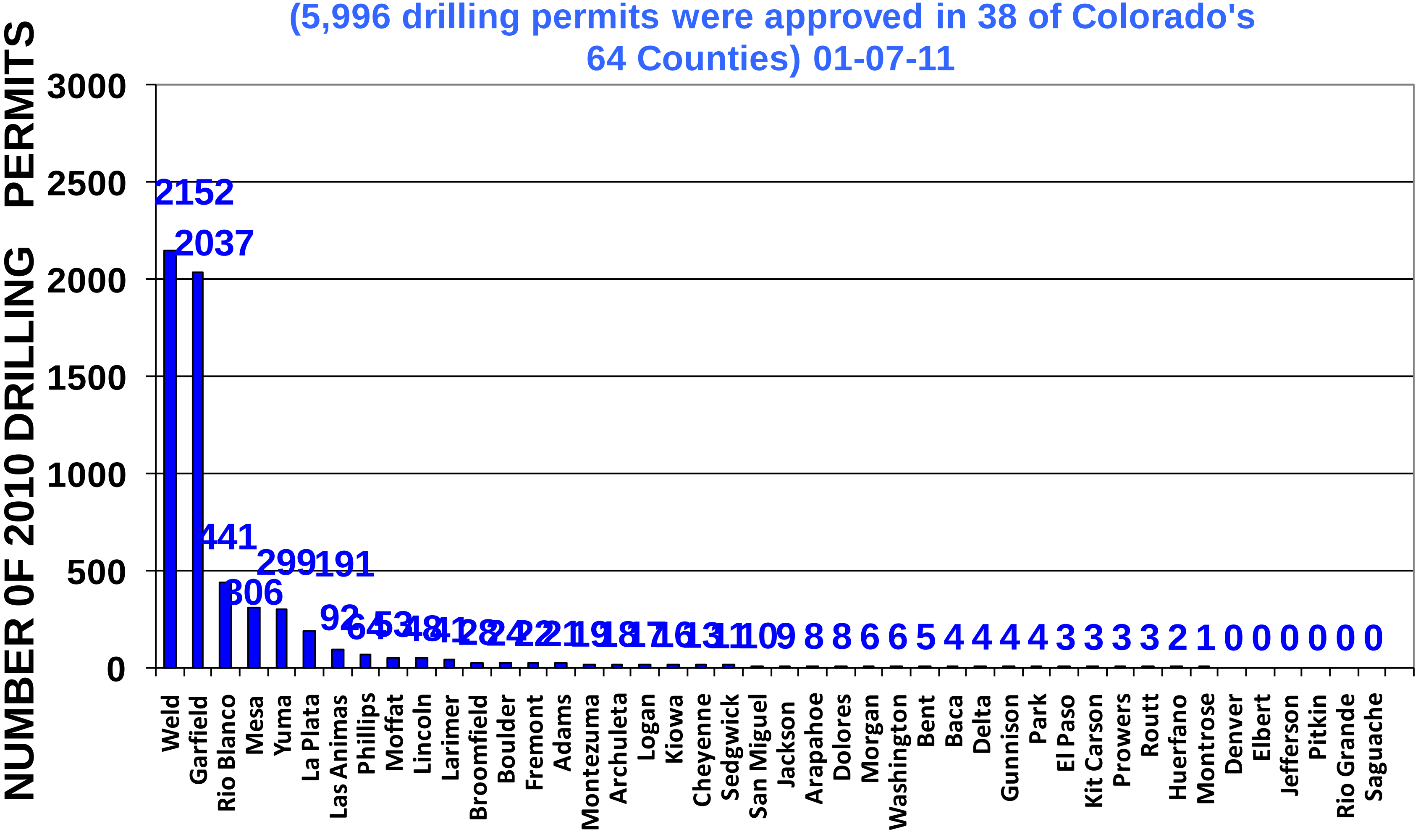
Number of Oil and Gas Well Permits For Wells Drilled Directionally & Horizontally From Common Well Pads in Colorado
11-07-11
Number of Applications For Permits To Drill
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
1529
125
1
2273
242
2007
312
7
2245
560
12
2917
890
8
4323
1762
57
5904
2773
53
6368
3649
86
8027
5007
95
5159
3585
171
5996
4194
462
4019
2428
761
Total APDS
APDs For Directional Wells From Common Well Pads
Horizontal

HISTORIC ANNUAL COLORADO DRILLING PERMITS 11-07-11



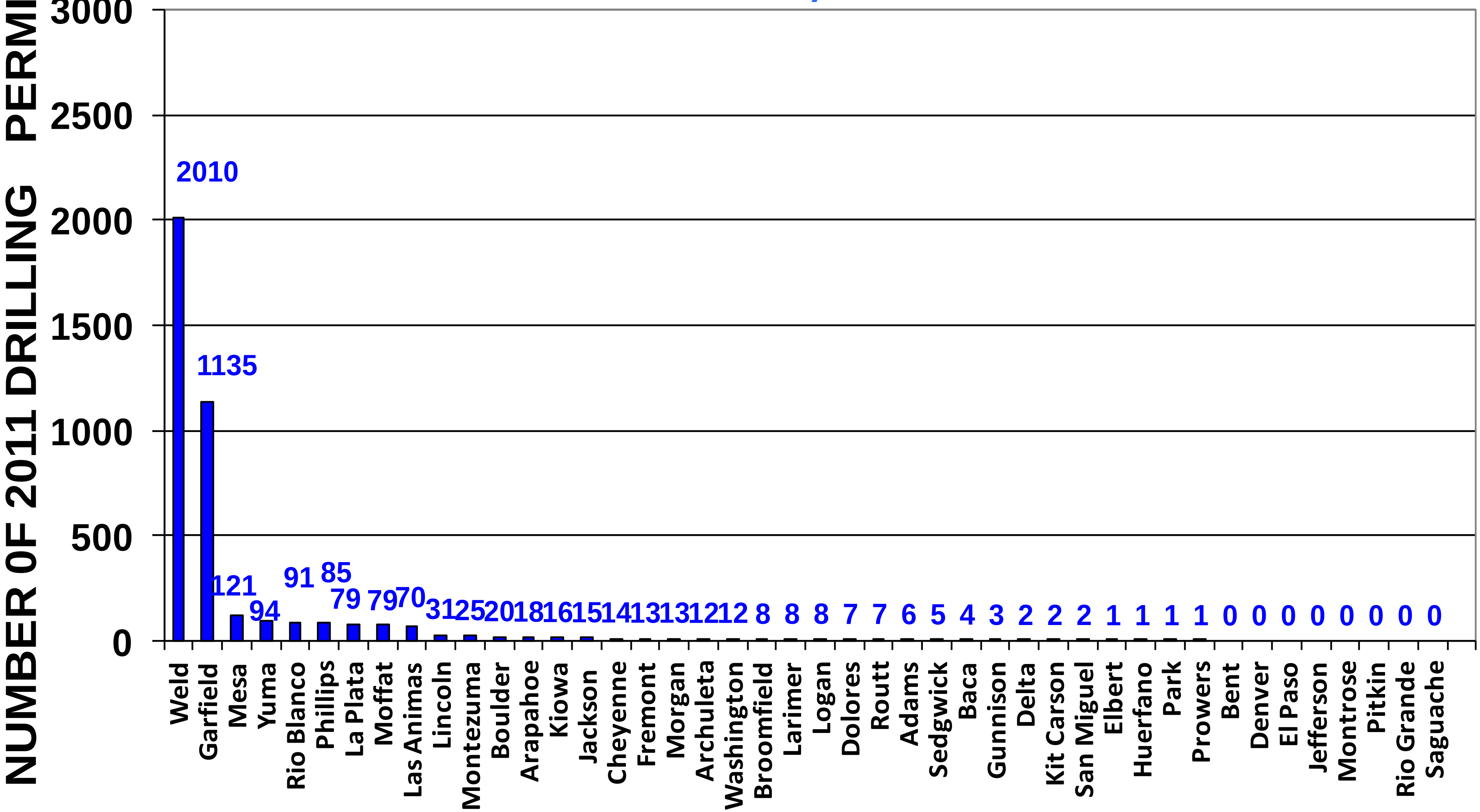
NUMBER OF 2010 DRILLING PERMITS, ALL COLORADO COUNTIES

(5,996 drilling permits were approved in 38 of Colorado's 64 Counties) 01-07-11



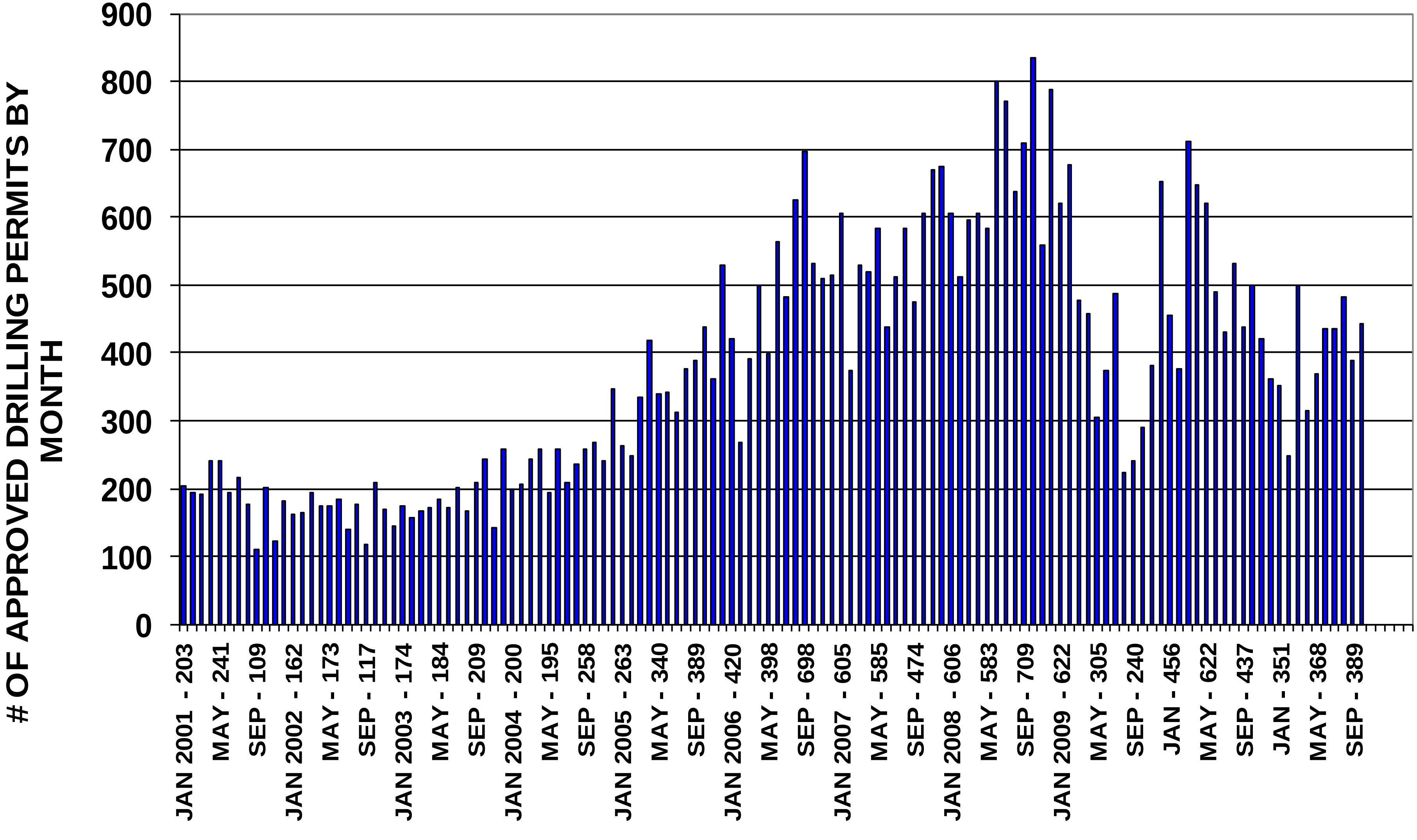
NUMBER OF 2011 DRILLING PERMITS, ALL COLORADO COUNTIES

(4019 drilling permits were approved in 36 of Colorado's 64 Counties) 11-07-11

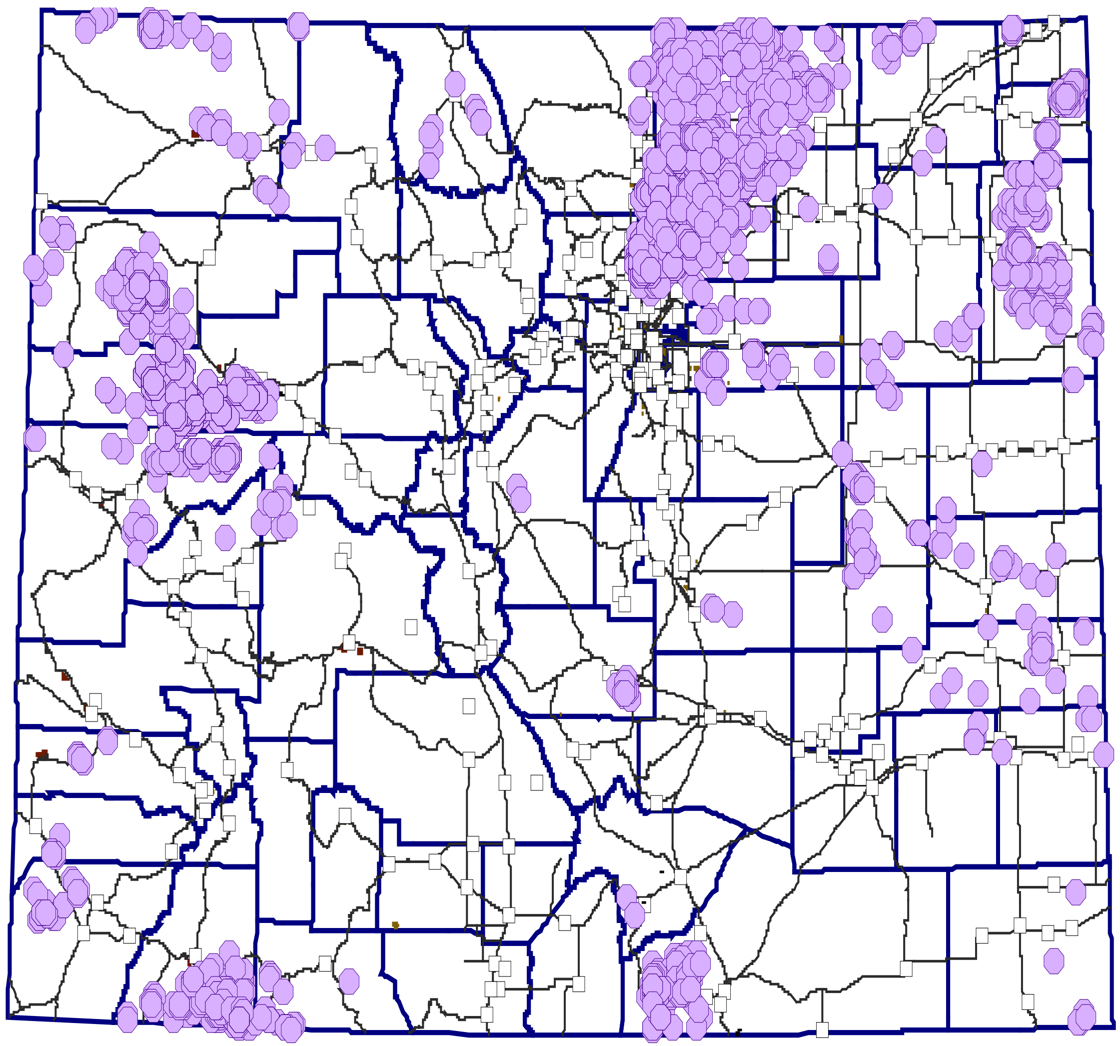


COLORADO MONTHLY APPROVED DRILLING PERMITS

as of 11-07-11

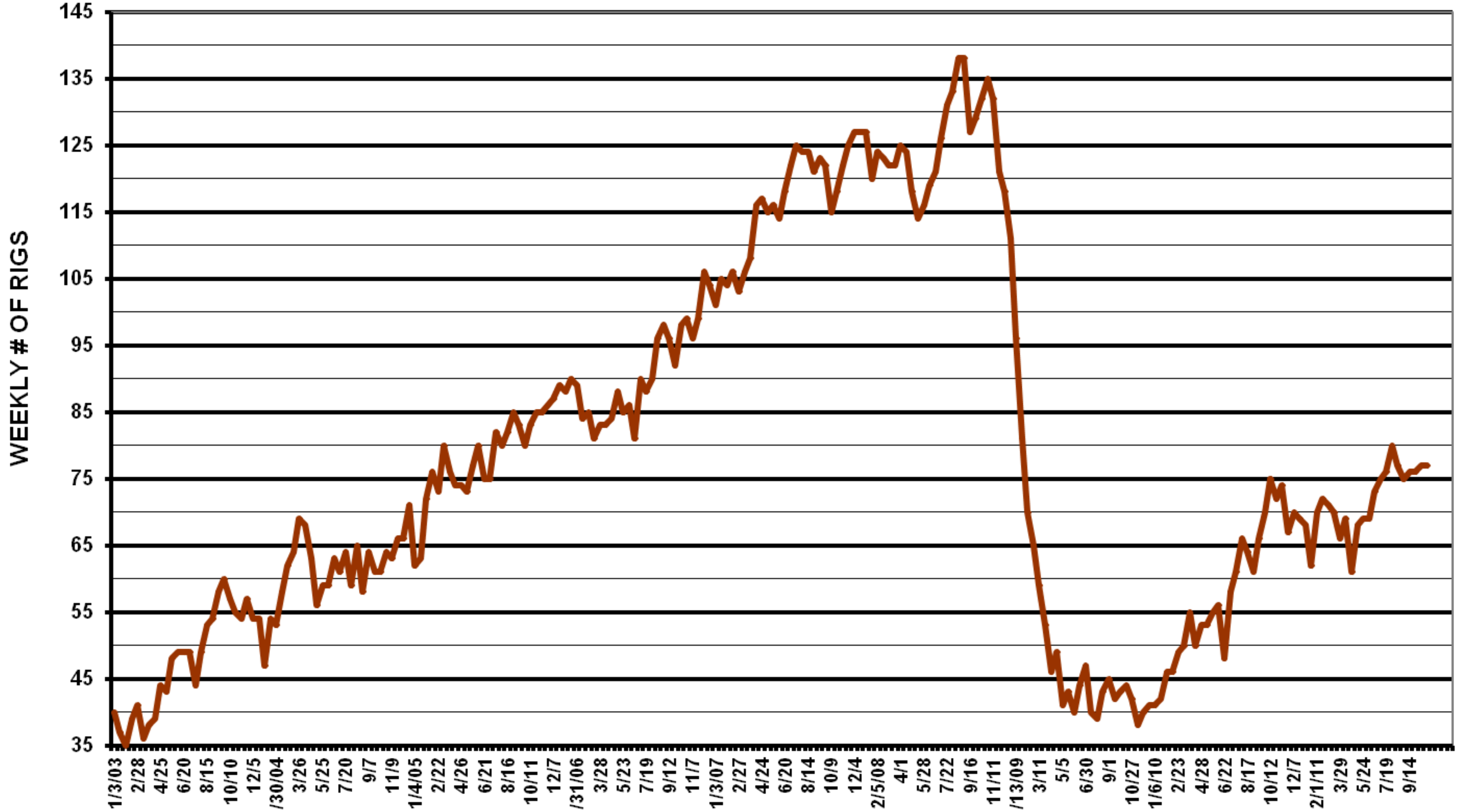


RECENT COLORADO OIL AND GAS WELL PERMITS 11-07-11



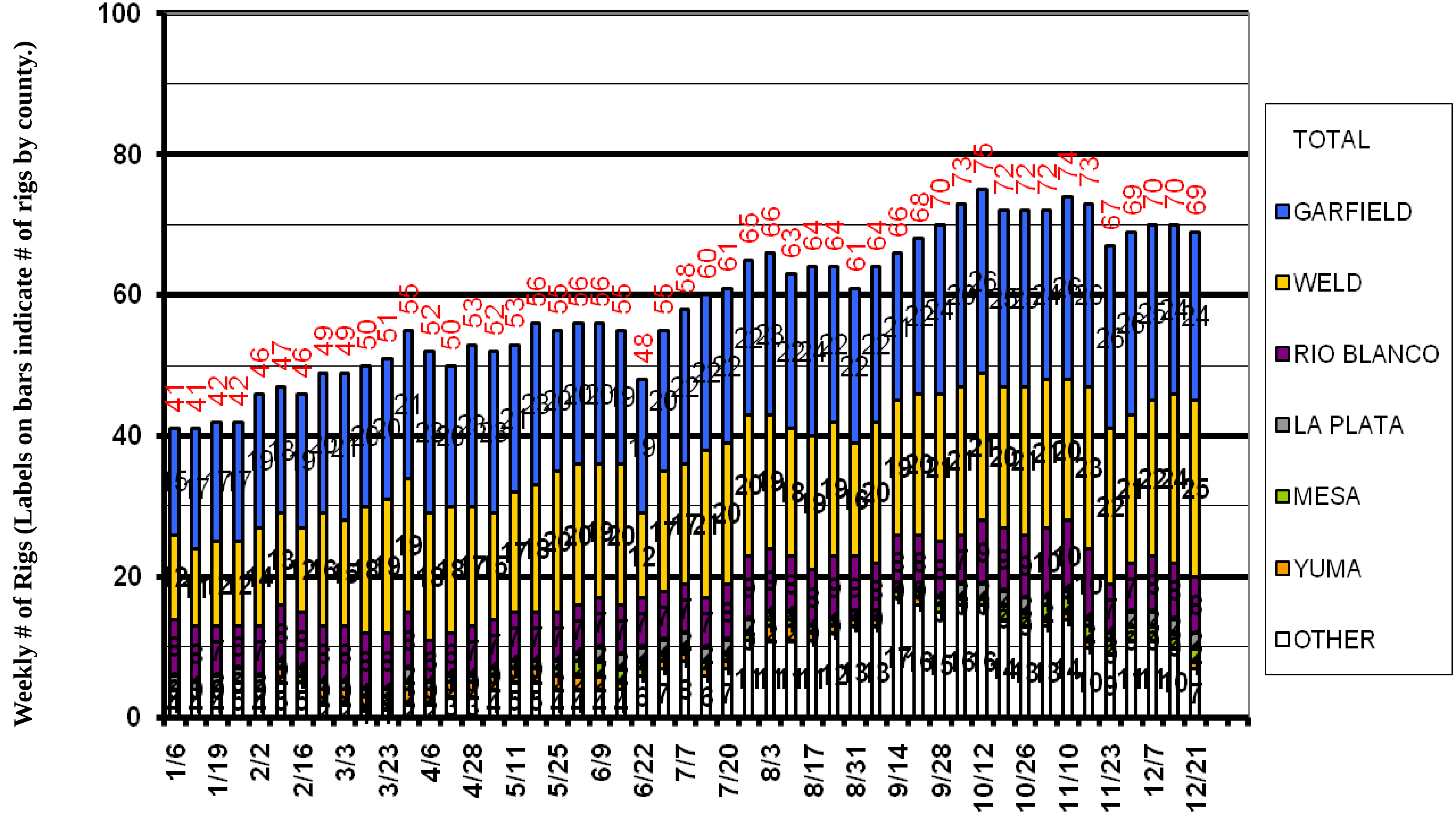
TOTAL DRILLING RIGS RUNNING IN COLORADO EVERY OTHER WEEK IN 2003-2011

(Based on Data in: through 4/30/03, PI/Dwights Drilling Wire -- after 4/30/03, Anderson Reports Weekly Rig Status Report)



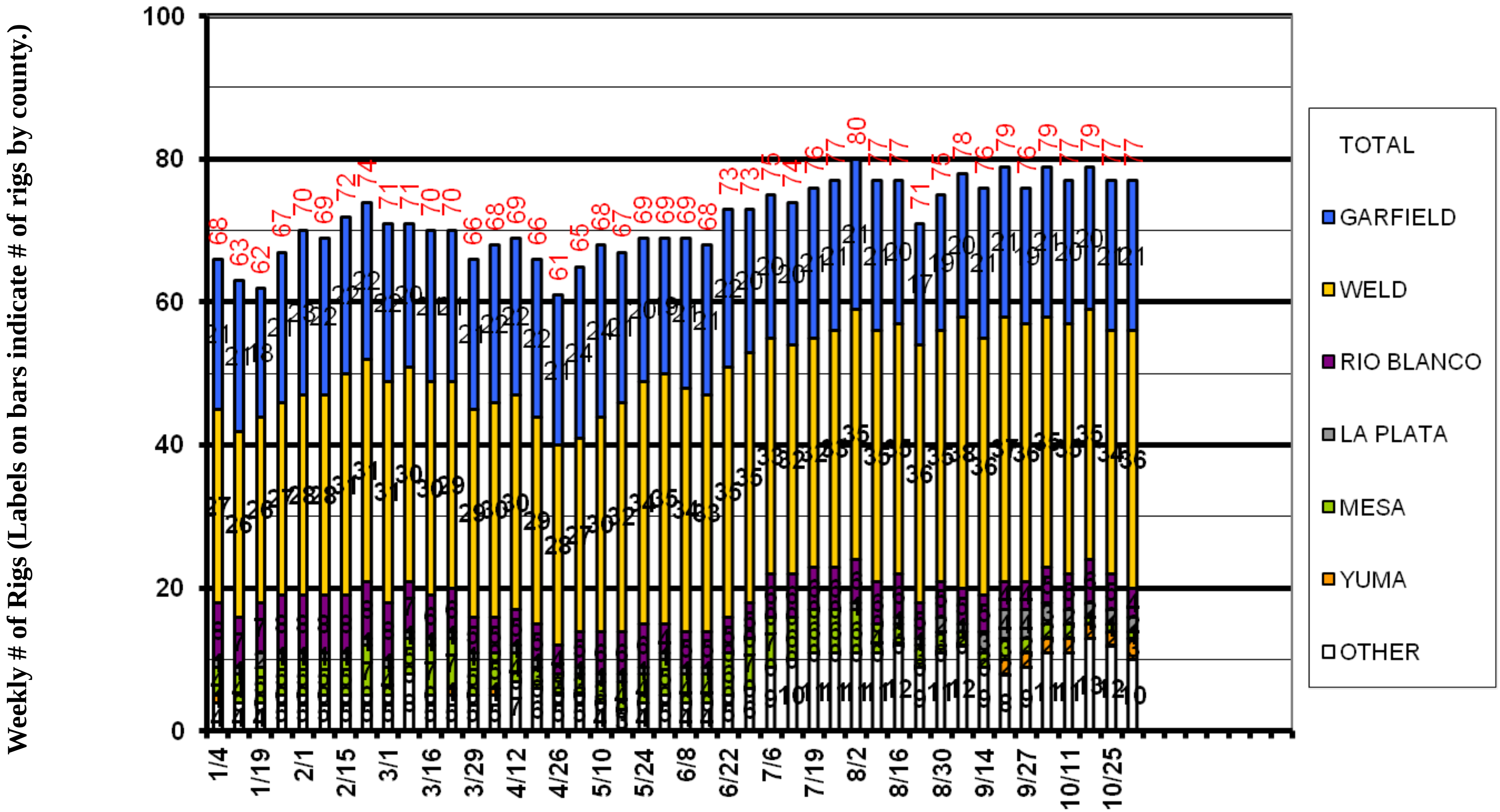
DRILLING RIGS RUNNING IN COLORADO BY COUNTY EACH WEEK IN 2010

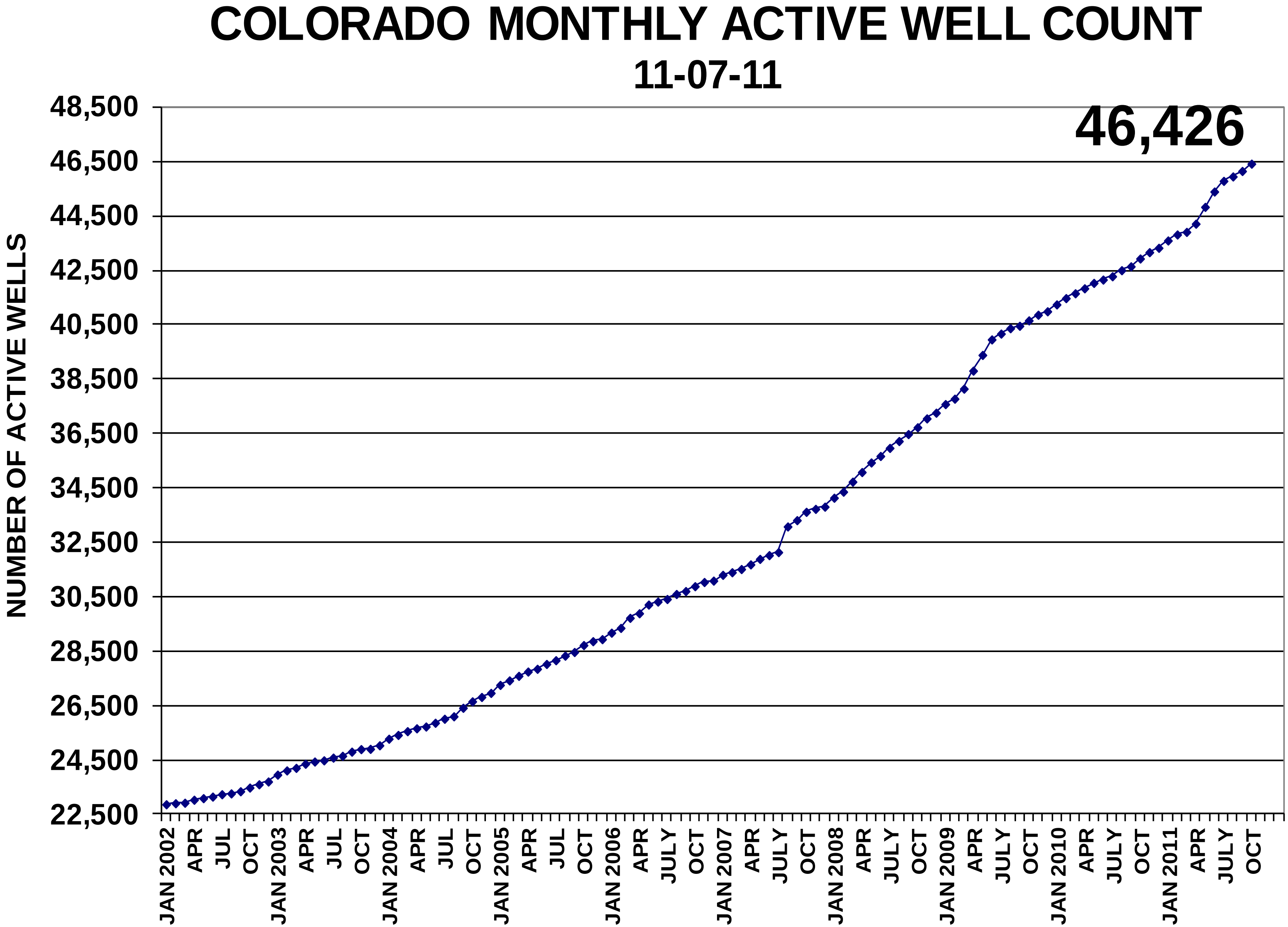
(Based on Data in Anderson Reports Weekly Rig Status Report)



DRILLING RIGS RUNNING IN COLORADO BY COUNTY EACH WEEK IN 2011

(Based on Data in Anderson Reports Weekly Rig Status Report)

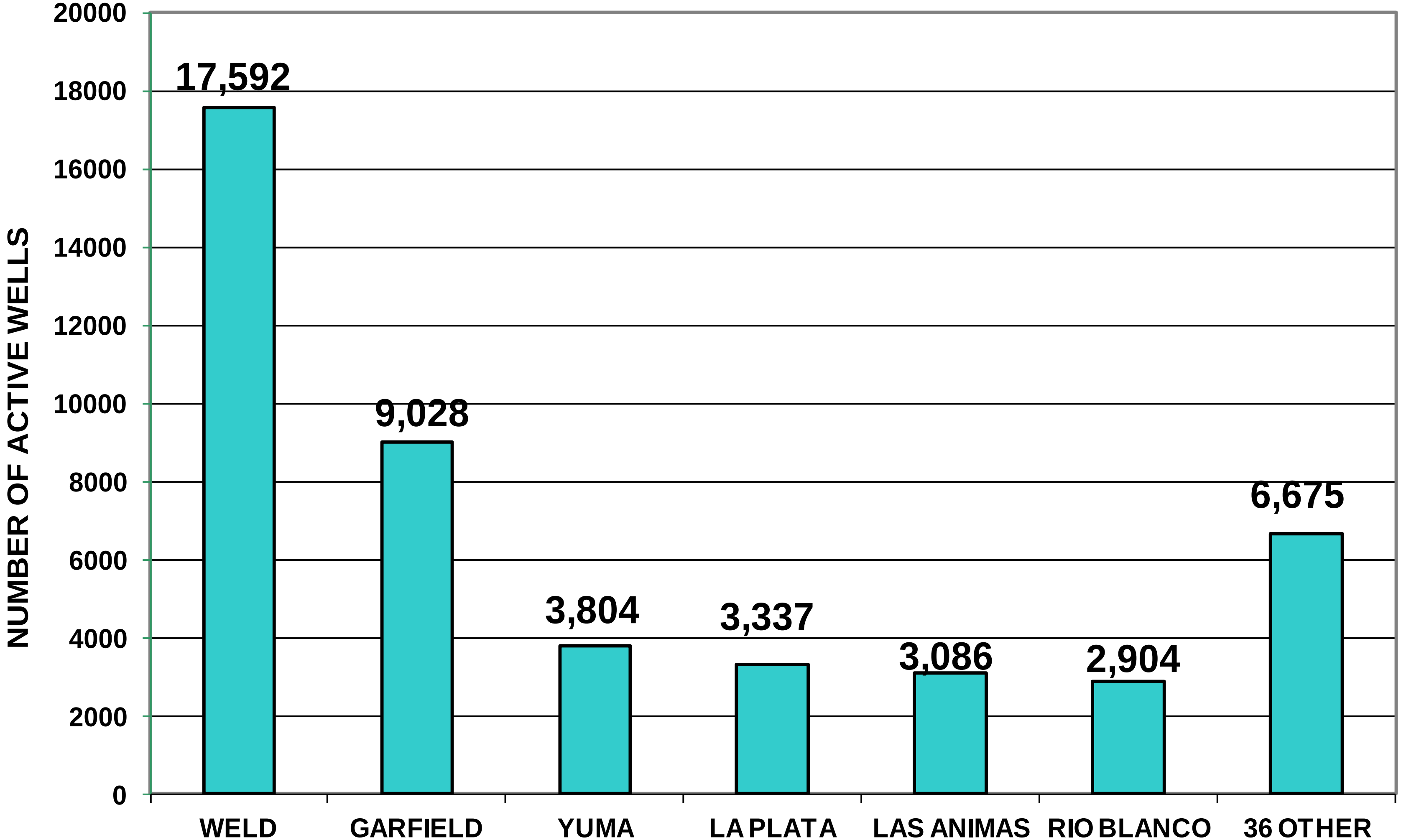



COLORADO MONTHLY ACTIVE WELL COUNT
11-07-11
46,426
NUMBER OF ACTIVE WELLS
48,500
46,500
44,500
42,500
40,500
38,500
36,500
34,500
32,500
30,500
28,500
26,500
24,500
22,500
JAN 2002
APR
JUL
OCT
JAN 2003
APR
JUL
OCT
JAN 2004
APR
JUL
OCT
JAN 2005
APR
JUL
OCT
JAN 2006
APR
JULY
OCT
JAN 2007
APR
JULY
OCT
JAN 2008
APR
JULY
OCT
JAN 2009
APR
JULY
OCT
JAN 2010
APR
JULY
OCT
JAN 2011
APR
JULY
OCT

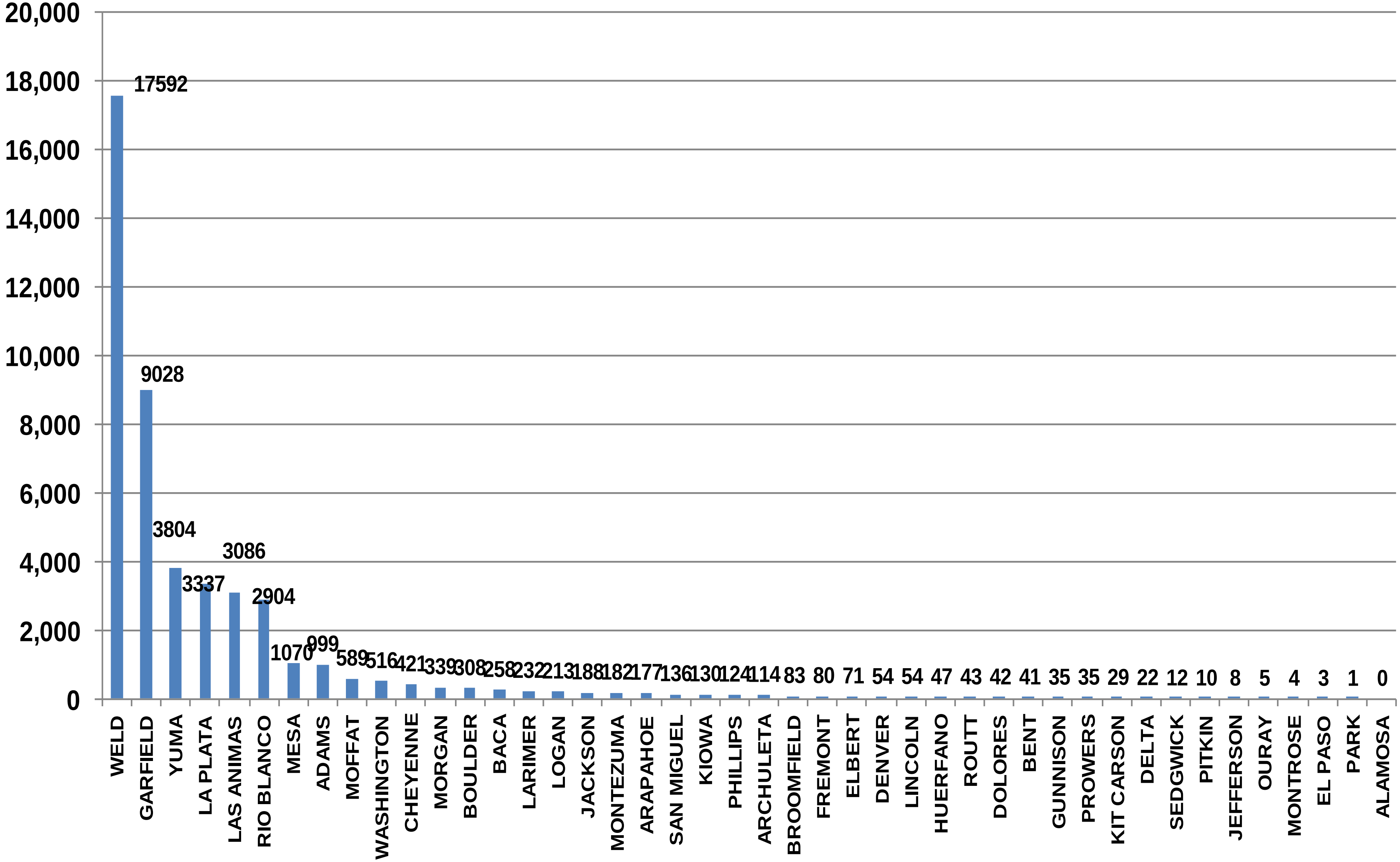
NUMBER OF ACTIVE COLORADO OIL & GAS WELLS BY COUNTY

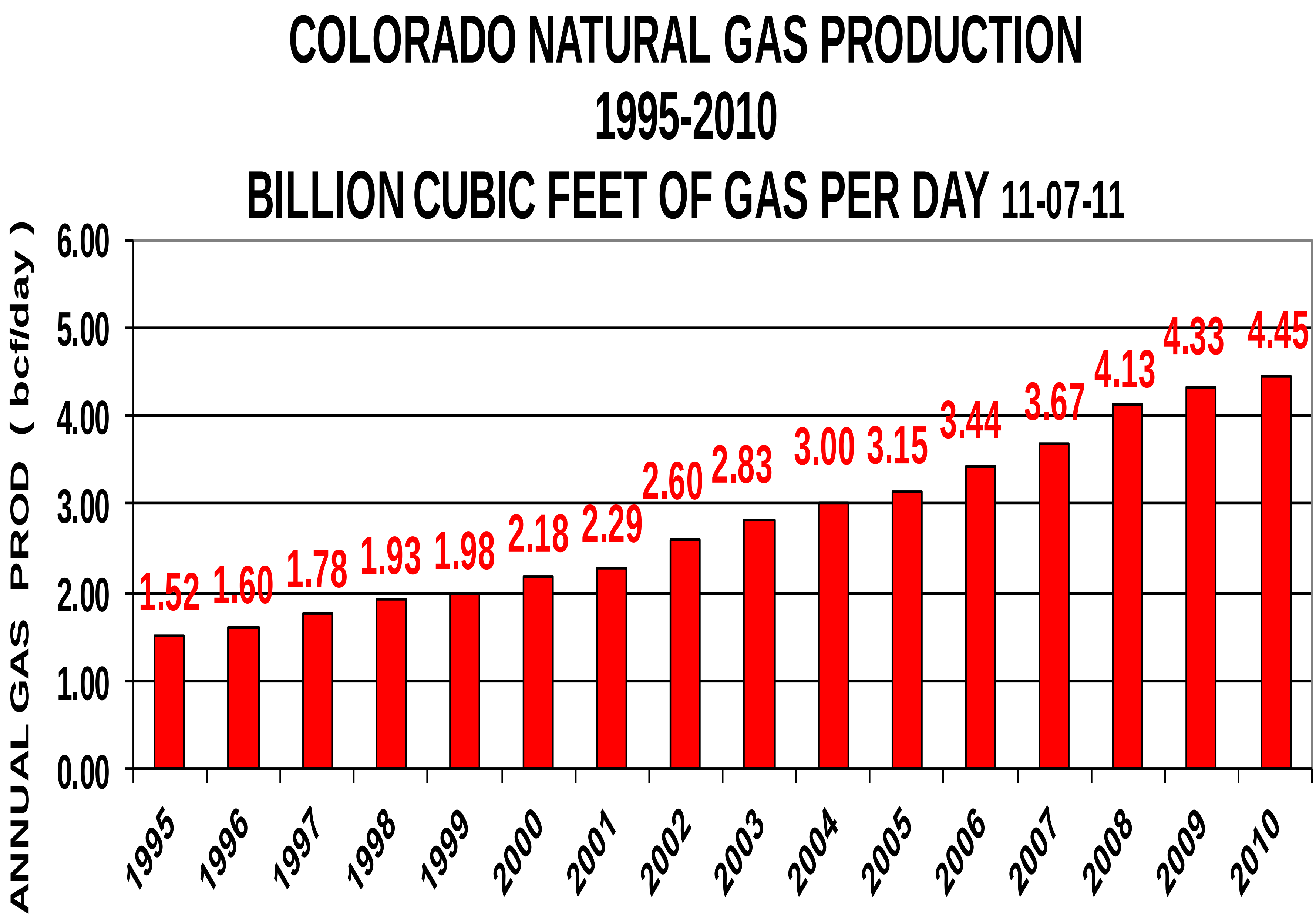
86.0% of Colorado's 46,426 active wells are located in these 6 counties

(11-07-11)

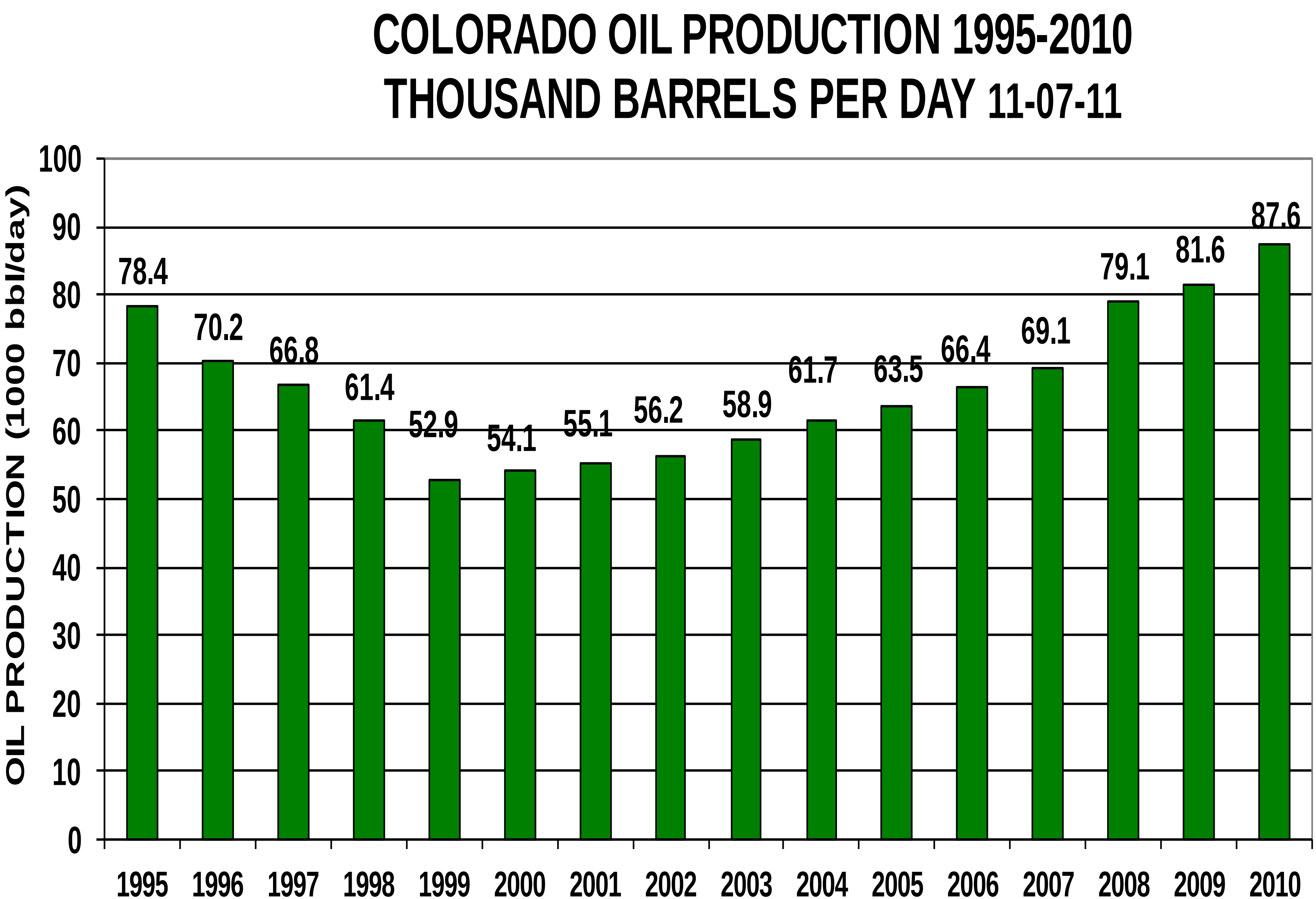


ACTIVE OIL & GAS WELLS – ALL COLORADO COUNTIES
11-07-11



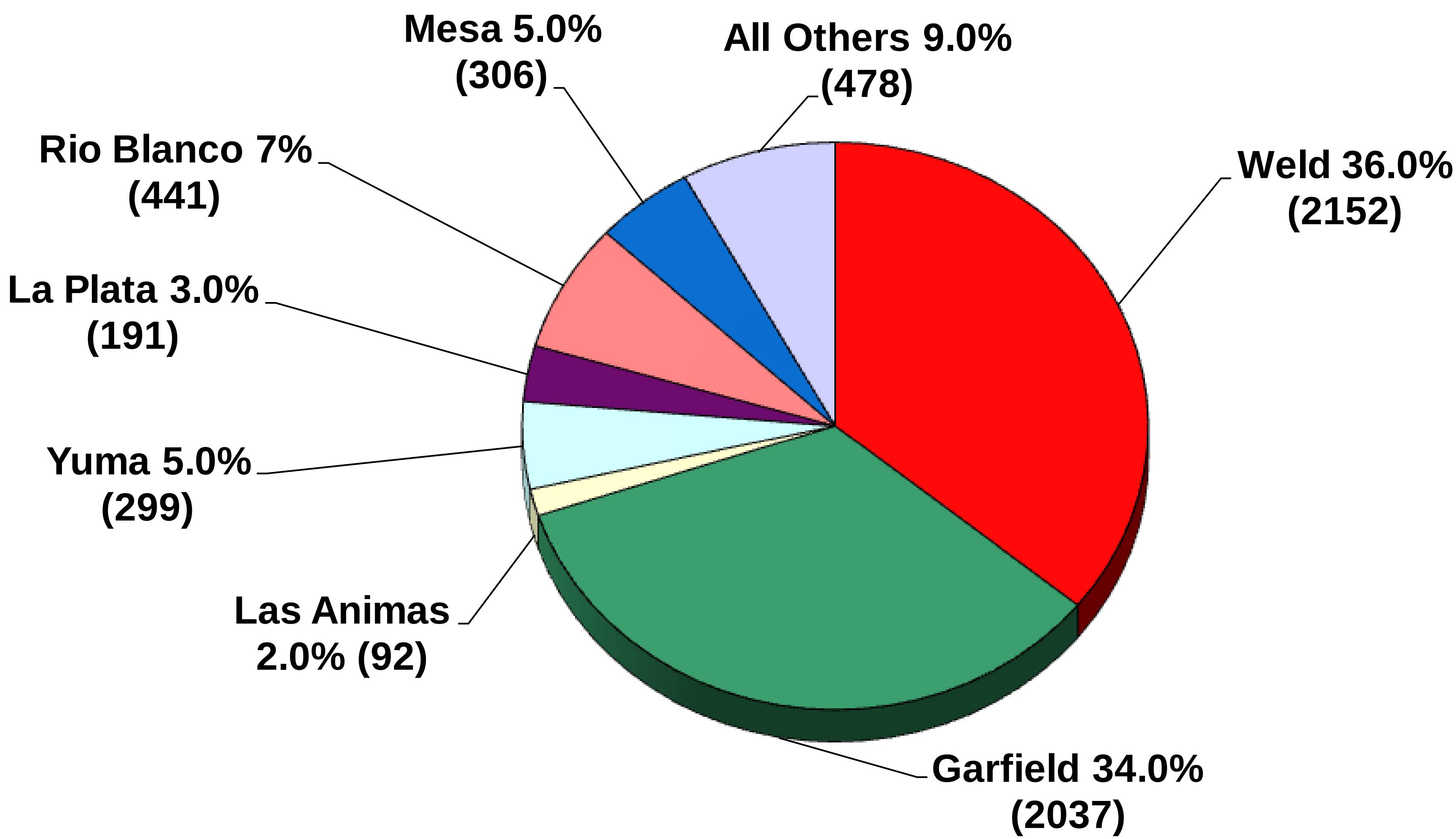


COLORADO NATURAL GAS PRODUCTION
1995-2010
BILLION CUBIC FEET OF GAS PER DAY 11-07-11
ANNUAL GAS PROD (bcf/day)
6.00
5.00
4.00
3.00
2.00
1.00
0.00
1.52
1.60
1.78
1.93
1.98
2.18
2.29
2.60
2.83
3.00
3.15
3.44
3.67
4.13
4.33
4.45
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010

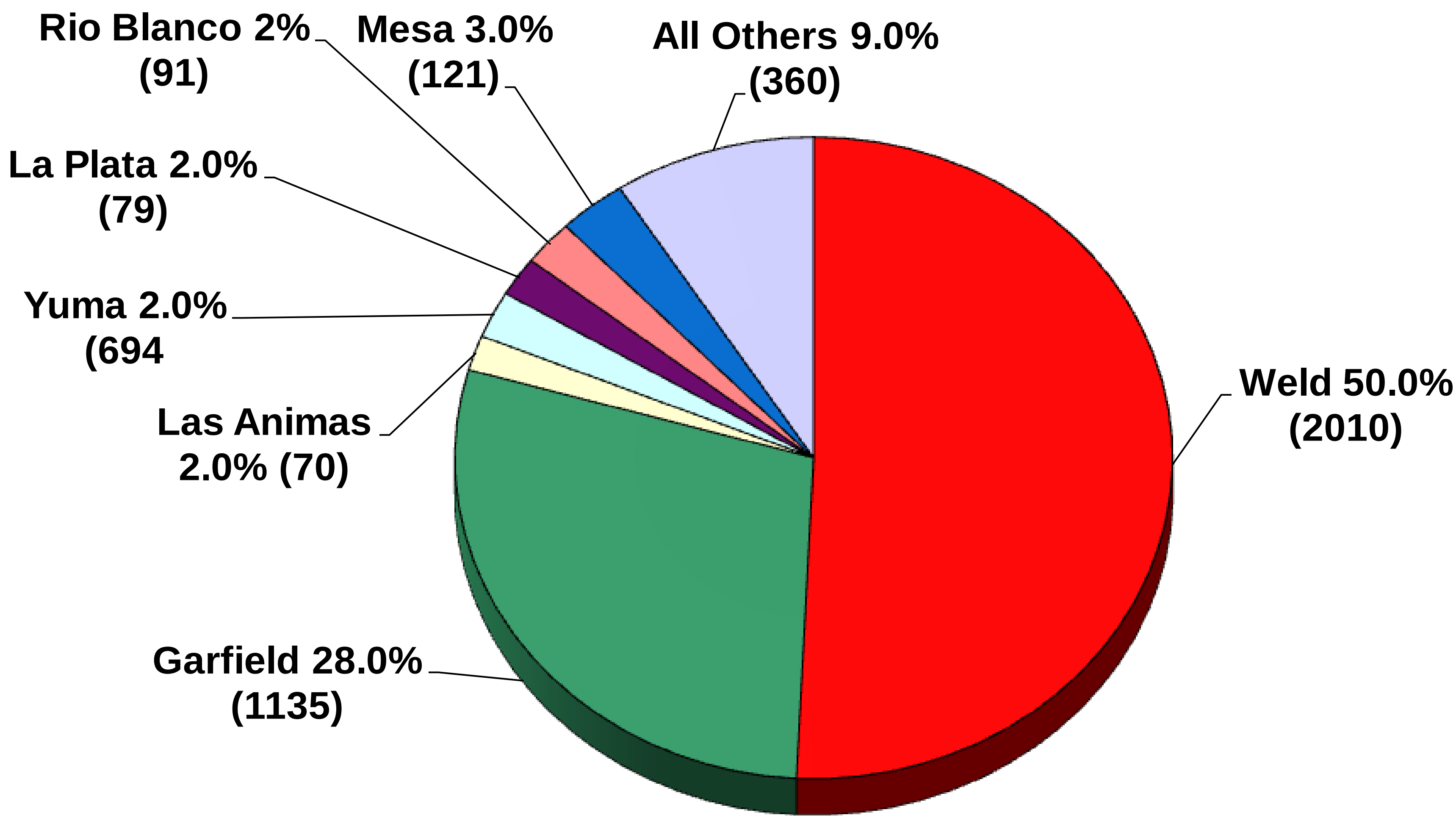

COLORADO OIL PRODUCTION 1995-2010
THOUSAND BARRELS PER DAY 11-07-11
OIL PRODUCTION (1000 bbl/day)
100
90
80
70
60
50
40
30
20
10
0
78.4
70.2
66.8
61.4
52.9
54.1
55.1
56.2
58.9
61.7
63.5
66.4
69.1
79.1
81.6
87.6
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010

COLORADO OIL AND GAS 2010 DRILLING PERMITS BY COUNTY

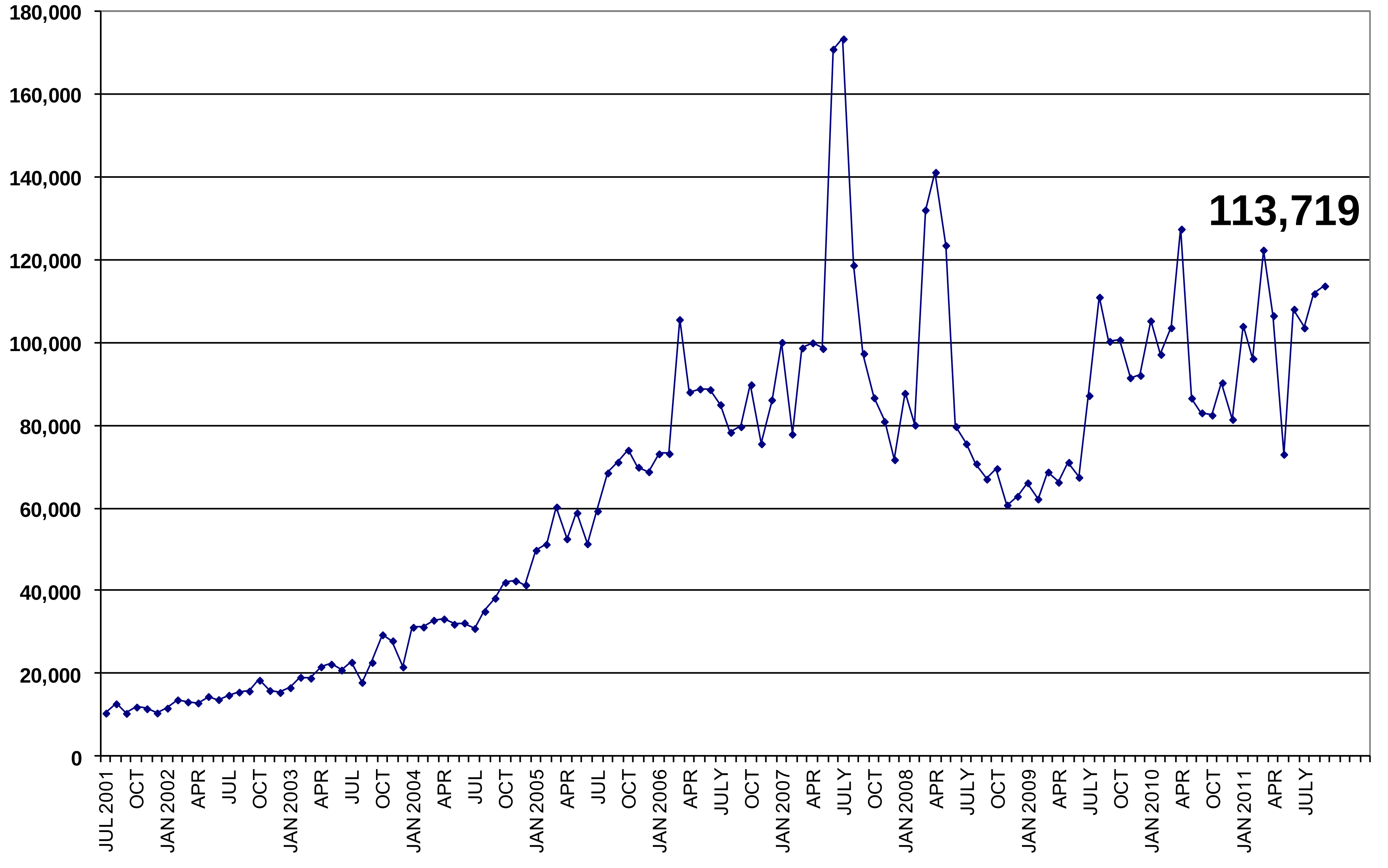
as of 01-07-11



COLORADO OIL AND GAS 2011 DRILLING PERMITS BY COUNTY
as of 11-07-11



COLORADO MONTHLY COGCC WEBSITE VISITS
10-07-11



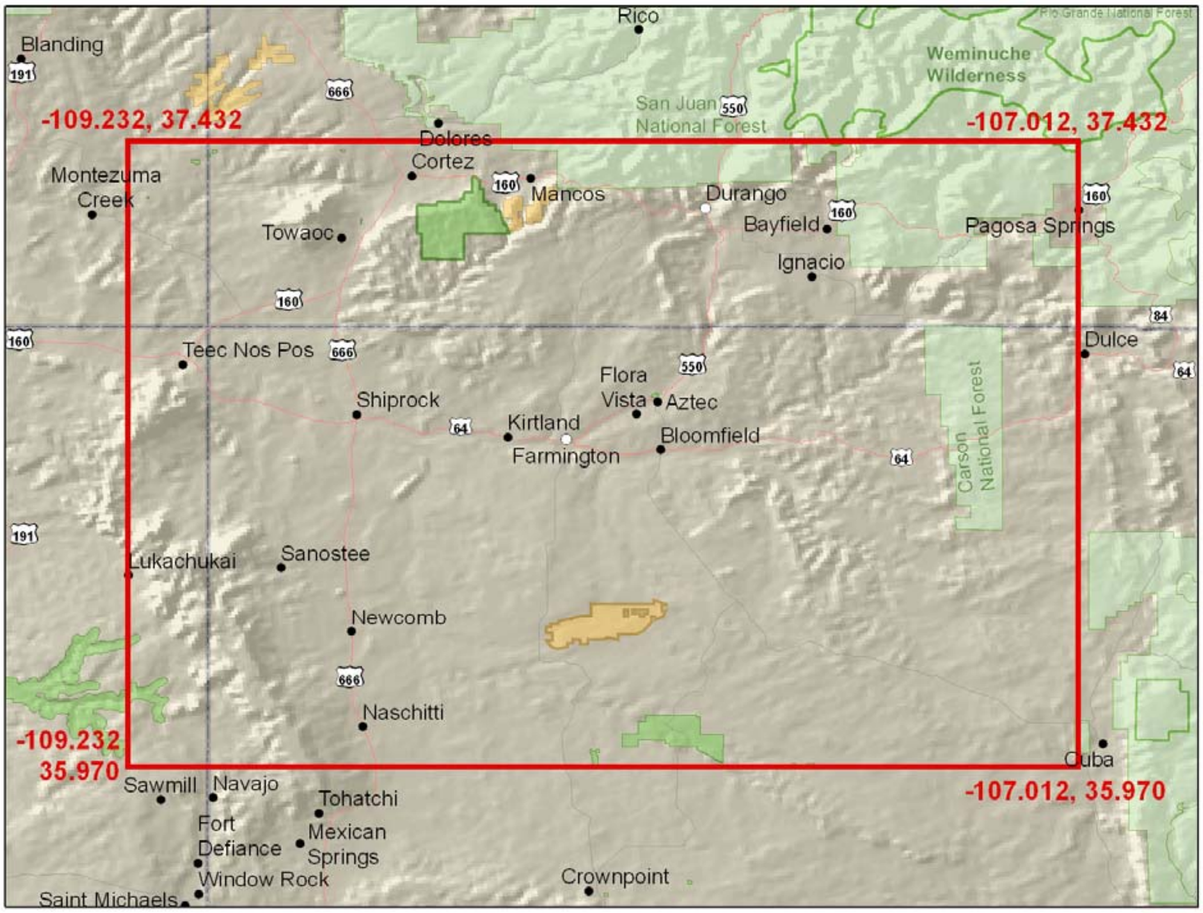
Colorado Oil & Gas Conservation Commission Statutory Requirements

*Please note that information within parentheses is additional background information and not a statutory requirement

Commissioner (Officer)	2 Executive Directors (ex-officio voting members) (Current Employment)	2 West of Continental Divide (Resident County)	3 with Substantial Oil & Gas Experience (Employed by Oil & Gas Industry) (Current Employment)	2 Out of 3 Must Have a College Degree in Petroleum Geology or Petroleum Engineering	1 Local Government Official (Current Employment)	1 with Substantial Environmental or Wildlife Protection Experience (Current Employment)	1 with Substantial Soil Conservation or Reclamation Experience (Current Employment)	1 engaged in Agricultural Production and a Royalty Owner (Current Employment)	Maximum of 4 from Same Political Party (excluding Executive Directors)	Current Term Expires
Richard Alward		X (Mesa)					X (Ecologist)		D	7/1/2015
Tom Compton Chairman		X (La Plata)						X (Rancher)	R	7/1/2015
Tommy Holton		(Fort Lupton)			X				R	7/1/2015
John Benton		(Littleton)	X	X					R	7/1/2015
W. Perry Pearce Vice Chair		(Denver)	X						D	7/1/2015
DeAnn Craig		(Denver)	X	X					R	7/1/2012
Andrew Spielman		(Denver)	X			X			D	7/1/2015
Mike King	X (Department of Natural Resources)	(Denver)								
Chris Urbina	X (Department of Public Health and Environment)	(Denver)								

Commissioner requrements are set by statute in the Oil and Gas Conservation Act at §34-60-104 (2) (a)(1), C.R.S. (Current as of 09-19-2011)

Four Corners Air Quality Task Force
Report of Mitigation Options



November 1, 2007

The report is a compilation of mitigation options drafted by members of the Four Corners Air Quality Task Force. This is not a document to be endorsed by the agencies involved, but rather, a compendium of options for consideration following completion of the Task Force's work in November 2007.

Four Corners Air Quality Task Force Members List

Task Force members were those individuals who regularly attended quarterly meetings, participated in one or more work groups, and who assisted in drafting and providing comments on the mitigation option papers and other sections of the Task Force Report.

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Roger Armstrong	Twin Stars Ltd.	Farmington, NM
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Four Corners Air Quality Task Force Interested Parties List

Interested Parties were those individuals who followed the progress of the Task Force, and who may have attended one or more quarterly meetings, may have participated in work groups and may have provided comments on sections of the Task Force Report.

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Background and Purpose

Overview

The states of Colorado and New Mexico convened the Four Corners Air Quality Task Force (Task Force) in November 2005 to address air quality issues in the Four Corners region and consider options for mitigation of air pollution. The Task Force is comprised of more than 100 members and 150 interested parties representing a wide range of perspectives on air quality in the Four Corners. Members include private citizens, representatives from public interest groups, universities, industry, and federal, state, tribal and local governments.

This report represents a two-year effort of the Task Force and is a compendium of options to address air quality concerns in the Four Corners. This report is the result of hundreds of hours of time volunteered by Task Force members. The report's contents should not be construed as the conclusive findings or consensus-based recommendations of all Task Force members, but rather as an expression of the range of possibilities developed by this diverse group. This report provides a unique and invaluable resource for the agencies responsible for air quality management in the Four Corners area.

Air Quality Background

The Four Corners area is home to more than 400,000 people in 10 counties. Beautiful landscapes, rich history and cultural heritage, and numerous outdoor activity opportunities drive a significant tourism industry. The area is also home to an extensive energy development sector that is experiencing unprecedented growth. Furthermore, population and urbanization is increasing in the area. Increases in industrial development and population generally bring increases in air pollution. Good air quality is important to both residents and visitors in the Four Corners area, and immediate attention to this resource is necessary to ensure its protection.

The Clean Air Act sets forth a variety of air quality standards and goals. For example, the U.S. Environmental Protection Agency (EPA) sets National Ambient Air Quality Standards for the most prevalent pollutants that are considered harmful to public health and the environment. The EPA, states, and some tribes are responsible for keeping clean areas clean under the Clean Air Act's Prevention of Significant Deterioration program. In fact, the Four Corners area air quality is potentially subject to the requirements of four states, numerous tribes, EPA and Federal Land Managers. This jurisdictional array was a primary driver for the need for this task force.

The Prevention of Significant Deterioration program requires regulatory agencies to determine whether air pollution is causing adverse impacts to water, vegetation, soils and visibility in our National Parks and Wilderness areas. The states are currently working on plans to improve visibility as required by the federal Regional Haze Rule.

One pollutant that has been decreasing across the west is sulfur dioxide. However, ozone, nitrates (formed from Oxides of Nitrogen) and particulate matter are of particular concern in the Four Corners region due to increased oil and gas operations, power plants, and general growth. This area has not exceeded the federal health standards for these pollutants, but air monitoring in the region has shown that concentrations are approaching federal ambient air quality standards for ozone. Regulatory agencies are working to ensure that pollutant levels in the Four Corners region remain below the federal air quality standards. These same pollutants also impair visibility—hindering the ability of an observer to see landscape features—and affect other sensitive resources such as water quality and ecosystems in the region. Views in the Four Corners area are routinely impaired by air pollution.

Another pollutant of concern in the Four Corners region is mercury. Mercury is a naturally occurring metal that is released into the environment from industrial operations and household waste, including coal-fired power plants, crematoria, disposal of common household products and equipment, and mining. Mercury builds up and remains in the ecosystem and can be found in toxic levels in fish in many areas. The EPA promulgated the Clean Air Mercury Rule in 2005 to permanently limit and reduce mercury emissions from coal-fired power plants through the year 2018. States are currently working to implement this program.

<u>Four Corners Air Quality Task Force</u>

The agencies responsible for managing air quality in the Four Corners include the four states (Arizona, Colorado, New Mexico and Utah), the federal agencies (EPA, the U.S. Department of the Interior's Bureau of Land Management and National Park Service; the U.S. Department of Agriculture's Forest Service), and the tribal governments (Navajo Nation Environmental Protection Agency, Ute Mountain Ute, Jicarilla Apache and the Southern Ute Indian Tribe's Air Quality Department). These agencies are addressing the air quality issues discussed above, and believe the input of the residents, representatives of industry and environmental groups is important in developing effective air management strategies. The EPA, BLM, state agencies and some tribes have authority to control sources of air pollution.

In 2004, these agencies decided to work together to explore collaborative ways to manage air quality in the Four Corners area. The agencies agreed that an organized and sustained public process would be beneficial to developing meaningful air quality management strategies for the area. In November 2005, the states of New Mexico and Colorado officially convened the Four Corners Air Quality Task Force (Task Force).

The purpose of the Task Force was to bring together a diverse group of interested parties from the area to learn about and discuss the range of air quality issues and options for improving air quality in the Four Corners area. It was decided at the outset that the Task Force would be a process completely open to anyone with an interest in air quality issues in the Four Corners area. This meant that member participation fluctuated from meeting to meeting, although no meeting had fewer than 65 attendees and Task Force participation in total reached some 250 individuals (Task Force members and interested parties combined).

Initial work of the Task Force has already resulted in the implementation of one "interim" recommendation: the Bureau of Land Management has required new and replacement internal combustion gas field engines of between 40 and 300 horsepower to emit no more than two grams of nitrogen oxides per horsepower-hour; and, in Colorado, all new and replacement engines greater than 300 horsepower must not emit more than one gram of NOx per horsepower-hour. In New Mexico, all new and replacement engines greater than 300 horsepower must not emit more than 1.5 grams of NOx per horsepower-hour. These requirements apply to oil and gas development within the Bureau of Land Management's jurisdiction.

The Task Force Process

A process was developed that would easily accommodate new members throughout the two-year time period, but provided enough continuity so that a work product could be developed. The Task Force was divided into five working teams: three "source" groups: Power Plants, Oil and Gas, and Other Sources; and two "technical" groups: Cumulative Effects and Monitoring. The purpose of the work groups was to exchange ideas and information, discuss mitigation options, receive input, and coordinate the development of the mitigation options relating to those sectors. The technical work groups coordinated existing data and analyses that could inform the work of the Task Force, as well as identified additional air quality analyses and monitoring that may be helpful to the responsible agencies in developing air quality management plans.

The Task Force met face-to-face on a quarterly basis from November 2005 through November 2007. These meetings took place in Farmington, New Mexico and Durango and Cortez, Colorado. Additional work was carried on between meetings via conference call, and some smaller group meetings were held as needed. The website developed for the Task Force was the primary vehicle of on-going communications with Task Force members, and was hosted by the State of New Mexico at: http://www.nmenv.state.nm.us/aqb/4C/index.html. The website aided in the Task Force being an open forum for the exchange of ideas, as well as an educative tool, resource and bulletin board for Task Force members, interested parties and others.

Participants in the Task Force drafted mitigation ideas throughout the process following a simple format to promote consistency. Participants could also provide written input at any time, which was incorporated into the document on an on-going basis. Since it was not the intention of the Task Force for all members to come to consensus, the convention of a "Differing Opinion" was used so that individual members could share views that contrasted with what the author(s) had written. These appear throughout the report with the words "Differing Opinion" in bold print followed by the commenter's language.

In addition to Task Force member on-going input, the process included a public review period that enabled any interested individual (including Task Force members) to review and comment on the document. These comments were then reviewed by Task Force members, and revisions were made as members deemed appropriate. The public review comments are appended to each work group section of this document.

The Four Corners Air Quality Task Force implementation was mainly funded by grants from the states of New Mexico and Colorado; the U.S. Department of Interior, Bureau of Land Management and National Park Service; the U.S. Department of Agriculture, Forest Service, and the U.S. Environmental Protection Agency. In addition, many citizens, private corporations, non-profit organizations and other agencies provided in-kind support as well as resources to advance the work of the Task Force.

The Task Force Report

The Task Force Report is comprised of more than 125 mitigation options written by Task Force members and is the product of their work together over the two year period. These options describe possible strategies for minimizing air pollution impacts in the Four Corners area. These options are organized by source sector: Oil and Gas, Power Plants, and Other Sources, with an additional section on Energy Efficiency, Renewable Energy and Conservation that addresses all sources. Each group first brainstormed a broad spectrum of possible mitigation options and then decided on which options would be drafted into mitigation option papers. Those options that were not drafted are included in the Table of Mitigation Options Not Written with the group's rationale for not including them as written papers in this document.

There are also two technical sections: one on monitoring that discusses analysis gaps and offers ideas for improved monitoring in the area, and one on cumulative effects that provides some quantified estimates of emission reductions for some of the options, as well as ideas for additional analysis. Ideally, each option would have included an analysis regarding quantified air quality and other environmental, economic and other costs and benefits, as well as the costs to implement. Such analyses can be extremely resource and time-intensive and as such, could not be included for all options, but was included in options as available.

The Path Forward

This report will be considered by the federal, state, tribal and local agencies as they develop air quality and land management strategies, which may include developing new and revising existing regulations, supporting new legislation, developing new outreach and information programs, and developing and/or expanding voluntary programs for emission reductions. For instance, states may pursue some mitigation strategies as they develop strategies to enact specific, mandatory programs such as Regional Haze. The Bureau of Land Management may use options such as permit requirements for energy production. Industries may voluntarily practice a mitigation strategy to avoid further regulation.

This work of implementation will be done cooperatively among all of the agencies when appropriate, and individually as needed. Some of this work will include additional analyses of incentives for voluntary programs, air quality modeling, economic analyses, feasibility studies, and review of additional monitoring data. To enact new regulations, every jurisdiction requires a different level of analysis be performed, so there may be varying levels of study on any given option that a regulatory agency decides to pursue. The analyses and recommendations of the Cumulative Effects and Monitoring work groups will inform these agency processes.

Conclusion

An initial goal expressed at the first Task Force meeting was for greater awareness and understanding of air quality issues among the residents of the Four Corners area. In the end, the Task Force provided a unique forum for learning, the exchange of ideas and information, and a venue for all people in the area with interest in air quality to get to know one another. The result is a better informed and cohesive group of individuals who can speak to and support air quality management in the Four Corners area. The group became so cohesive that it was decided to reconvene the Task Force in approximately six months time to review progress made from the date of the Task Force Report's completion.

The work of the Task Force represents an invaluable resource to the agencies responsible for air quality management in the Four Corners area, and also for the general public as air quality management planning moves forward. The Task Force Report and process provides a model for other areas with similar concerns.

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Oil and Gas

Oil and Gas: Preface

Overview

The Oil & Gas Work Group of the Four Corners Air Quality Task Force was tasked with analyzing emission mitigation strategies for this industrial sector. For each Mitigation Strategy, and to the extent practicable, the Work Group documented the description of each strategy as well as implementation and feasibility considerations.

Participation in the Oil and Gas Work Group involved state, local and tribal air quality agencies, federal land management agencies, industry representatives, public citizens, and representatives of environmental organizations. Over six working sessions and many monthly conference calls, the work group identified more than 75 potential mitigation strategies. These mitigation strategies were then discussed and either drafted as a mitigation option paper, or eliminated from further analysis where a rationale to do so existed (see Table at the end of this document). The vast majority of the options discussed are represented herein by mitigation option papers for a total of 51.

Organization

The Oil and Gas industry is generally divided into sub-sections according to process. The Work Group used this progression in process to address each stage of the industry, with the exception of exploring Mitigation Options for Engines as a unique section that applies across the processes in the industry. For the purposes of organization and analysis of available Mitigation Strategies, the Oil and Gas portion of the TF Draft Report follows the sequence of definitions as identified below:

1. **Engines:** The work group addressed engines as a separate category in its analysis attributable to all processes in the oil and gas industry. The mitigation strategies were created to address the subcategories of stationary or mobile/non-road engines, drill rig engines, and turbines.
2. **Exploration & Production (E & P):** the work group defined E & P as the upstream sector of the oil and gas industry, including all activities associated with drilling, completion, and putting the well on-line. The work group identified and developed mitigation strategies for specific equipment in E&P, including oil/condensate tanks, dehydrators/separators/heaters, fugitive emissions associated with pneumatic operations, completions, and wellhead considerations.
3. **Midstream:** the work group defined Midstream Operations as occurring after custody transfer, including facilities such as compressor stations, gas processing plants, and transmission or storage of natural gas. Where appropriate, the work group devised mitigation strategies that avoided general overlap with E & P options, and concentrated primarily on options unique to the "midstream operations" that were not otherwise examined in the context of E&P operations.

The Work Group also identified and developed mitigation strategies that address **Overarching** and **Energy Efficiency and Renewable Energy** appropriate for consideration of application to the oil and gas industry.

ENGINES: STATIONARY RICE

Mitigation Option: Industry Collaboration

I. Description of the mitigation option

Overview

- This option explores the possibility of industry collaboration with engine manufacturers to achieve and reliably maintain emissions at or below prescribed levels for upcoming emission standards (i.e., NSPS for engines) on new engines. Such technologies could include but are not limited to lean burn or non-selective catalytic converters (NSCR) with air-to-fuel ratio controllers. The focus on such an effort would be on natural gas fired engines site rated at less than 300 hp.

Air Quality and Environmental Benefits

- This option would result in air quality improvement since all new engines built would meet lowest achievable emission controls at that time for criteria pollutants.
- **Differing opinion**: Reasonably available control technology is the accepted term used by EPA, industry, and regulatory entities versus lowest achievable emission controls that have a different connotation.

Economic

New Engines:

- Depending on the final emission levels established through this effort, operators might have to spend resources ensuring that prescribed emissions limits are being maintained.
- If through this option emission levels are set at levels lower than upcoming federal standards, then detailed engineering/economic analyses should be conducted to examine the incremental cost to control (over the federal regulatory baseline) and to determine if such additional controls are consistent with other programs.

Existing Engines:

- If such a program were expanded to include the retrofitting of all existing engines with current emission control technology, this would require a large capital investment from companies to achieve this result. This would result in replacement of older compressor engines, particularly those less than 200 hp,
- **Differing Opinion:** new engines would be a significant cost to the oil and gas industry. The salvage value of older compressors is a fraction of the cost of a new compressor engine.
- It would require companies to commit to ordering new engines over a prescribed time, likely ahead of when older units would have been replaced.
- The manufacturers would need confirmed orders to justify re-tooling their plants to meet the demand.

Trade-offs

- The use of given emission control technology could result in other emissions. For example, the use of lean-burn technology on a large scale would result in incremental emissions of formaldehyde. If NSCR is used on a large scale, it is believed ammonia emissions would result. However, it is not known if these emissions would be significant.
- Some engine manufacturers that cannot meet the demand and/or re-tool their factories could lose their market share in the San Juan Basin. Need to ensure this does not create any restraint of trade concerns.

II. Description of how to implement

A. Mandatory or voluntary: It could be both. The companies could begin a process of placing new orders voluntarily or the agencies, through regulatory/rules, could require emission levels that necessitate ordering new compressor engines.
Differing opinion: If this is industry collaboration with engine manufacturers, then the regulatory agencies should not expand to rule making that has requirements more stringent than NSPS.

B. Indicate the most appropriate agency(ies) to implement: State Environmental Agencies.
Differing opinion: Not appropriate. If this is industry collaboration with engine manufacturers, then the regulatory agencies should not expand to rule making that has requirements more stringent than NSPS.

III. Feasibility of the option

A. Technical: None identified although some field trials and bench scale tests are probably necessary to assess actual emissions on the new engines.
Differing opinion*:* EPA has assessed the technological feasibility of controlling these types of engines (See NSPS Mitigation Option Paper below.)

B. Environmental: Yes, from the Cumulative Effects group depending upon what type of emission control technology is preferred. The control technology that will be used will be based on the emission level selected, the lowest cost method of achieving the desired level of emission reduction and the reliability of maintaining emissions at the desired level. Ultimate decisions regarding control options should be based on measurable improvements in ambient air quality.

C. Economic: Economic burdens associated with engine replacement and manufacturer re-tooling are likely to be substantial.

IV. Background data and assumptions used

Emission inventories compiled for the Farmington, NM BLM Resource Management Plan (2003) and Southern Ute Indian Reservation Oil and Gas Environmental Impact Statement (2002).

- Preliminary discussions with companies and engine manufacturer representatives.
- Will need to integrate any more recent emissions inventory data from the Cumulative Effects Group.

V. Any uncertainty associated with the option (Low, Medium, High)

High, especially pertaining to economic feasibility and availability of field proven engines. High due to economics of replacing a large fleet of existing compressor engines and the timing that would be required to begin manufacturing a number of small horsepower engines.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

May need to verify with other work groups if manufacturing a large number of new compressor engines, particularly in the smaller horsepower range, could conflict with other new engine initiatives such as building Tier II and Tier III diesel engines and meeting requirements for additional NSPS general regulations.

Mitigation Option: Install Electric Compression

I. Description of the mitigation option

Overview

- Electric Driven Compression would involve the replacement or retrofit of existing internal combustion engines or proposed new engines with electric motors. Retrofit of internal combustion engines with electric drivers is not generally feasible. Not all compressors can be fitted with an electric motor. This normally requires either a complete package change or, at very least, gear modifications. Electric motors would be designed to deliver equal horsepower to that of internal combustion engines. However, the electric grid capacity in any given area may limit the size/number of electric engines potentially supportable. The reliability of the grid and the easements also must be considered.

Air Quality/Environmental

- Elimination of local emissions of criteria pollutants that occur with the combustion of hydrocarbon fuels (natural gas, diesel, gasoline). Displacement of emissions to power generating sources (utilities) primarily from coal fired power plants (with higher emissions than natural gas fired engines) or natural gas fired peaking units.
- The "emissions balance" for switching to 4-corners grid electricity is illustrated in the table directly below. As apparent, the switch is not necessarily positive when compared with "modern" gas-fired reciprocating engines. The actual "balance" would depend on the particular engine model being compared to an electrical option.

4 Corners Grid Average Emissions lbs/MWh (From NRDC Database) (Average of PNM, Xcel, and Tri-State)	
SO2	3.4
NOx	3.8
CO2	2,473
Caterpillar 3608 LE Average Emissions lbs/MWh (equivalent)	
SO2	0
NOx	2.9
CO2	1,138
Cat. 3608 Assumptions: 9815 Btu/kw-hr "Sweet" Natural Gas NOx - 1 g/hp-hr 1 cu ft gas = 1,000 btu	

See also Cumulative Effects Analysis for this option for further emissions analysis.

Economics

- The costs to replace natural gas fired compressor *engines* with electric motors would be costly. Not all natural gas fired compressors can be fitted directly with an electric motor. This normally requires a complete package change or at very least, gear modifications.

- The costs of getting electrical power to the sites would be extremely high in most cases. It could require a grid pattern upgrade, which could costs millions of dollars for a given area. Maintenance and repair costs associated with the electrical power source are not included.
- A routine connection to a grid with adequate capacity for a small electric motor can be $18K to $25K/site on the Colorado side of the San Juan Basin.
- A scaled down substation for electrification of a central compression site can range between $250K and $400K.
- Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small.

Tradeoffs

- While the sites where the electrical motors would be placed would not be sources of emissions, indirect emissions from the facilities generating the electricity would still occur such as coal-fired power plants.
- Additional co-generation facilities would likely have to be built in the region to supply the amount of electrical power needed for this option. This would result in additional emissions of criteria pollutants from the combustion of natural gas for turbines typically used for co-generation facilities. Co-generation produces both power and steam; as there is not a market for the steam, this might just be a need for additional power plants or combined cycle plants. Lead time and cost for permitting and new base load generating facilities could be substantial.
- There would need to be possible upgrades in the electrical distribution system. However, the limitation of doing so is predicated by the electrical grid that would exist in a given area to provide the necessary capacity to support electrical compression.
- When comparing emissions from electric generating facilities used to power electric compressors versus natural gas fired compressors, differences in emission rates as well as overall energy efficiency must be examined.

Burdens

- The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry. Extensive capital investments could be required if new generating facilities are needed to meet the electrical demand of this option.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary based on economics of meeting emission reduction requirements and/or initiatives and feasibility of implementation.

B. Indicate the most appropriate agency(ies) to implement: No agency action needed to implement a voluntary program.

III. Feasibility of the option

A. Technical: Feasible depending upon the electrical grid in a given geographic area and overall available electrical power for large-scale conversion in a given geographic area.

B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Indirect emission implications for grid suppliers should be considered (e.g., coal-fired plants).

C. Economic: The economics of implementing this option are much larger than stated above. Considerations such as (but not limited to): 1) cost of energy; 2) electrical demand; 3)reliability; and 4) efficiency need to be included in such an analysis. Costs to control calculations are needed to determine if they are consistent with other options being considered. Modeling needs to be conducted to evaluate if potentially shifting emissions from natural gas to coal would result in ambient air quality benefits.

IV. Background data and assumptions used
The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff.

V. Any uncertainty associated with the option (Low, Medium, High):
HIGH to MEDIUM based on land accessibility (easements), electric source availability and reliability of uninterrupted supply, advancing GHG legislation/regulation, and economics.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups:
Possibly the Cumulative Effects Group due to indirect emission increases from coal-fired plants. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Install Electric Compression (Alternative - Onsite Generators)

I. Description of the mitigation option

Overview

As an alternative to grid power dedicated on-site natural gas-fired electrical generators can be used to supply power to electric motors that replace the selected RICE compression engines. The electric motors would be rated at an equivalent horsepower to that of RICE engines currently used for gas compression. The power sources for the electric compression could consist of a network of on-site gas-fired electrical power generators. The alternative could be expanded to include consideration of replacement of other engines, such as, gas-fired pump-jack engines used as "prime-movers."

The currently available gas electric generator run on variety of fuels including low fuel landfill gas or bio-gas, pipeline natural and field gases. The gas electric generators are available in the power rating from 11 kW to 4,900 kW. Decisions on the use of on-site generators to replace natural gas-fired engines and the number of generators required would depend on a number of factors, including the proximity, spacing and size of existing engines. As a simple example using the conversion factor of 1 MW = 1,341 HP, adding a 1 MW natural gas-fired generator could replace an inventory of approximately 33 small (40 hp) internal combustion engines if these were reasonably close proximity, say spaced within a one or two mile radius. However, in "real world" operations, there will be several factors involved in determining the number of required gas-fired electrical generators; such as transmission loss, ambient operating temperature, load operating conditions, pattering of applied loads, etc.

Air Quality/Environmental Benefits

The emissions from gas electrical generators are relatively low compare to smaller internal combustion engines because of new technology and ability of controlling emission from big engines. For example a Caterpillar G3612 gas electrical generator with power rating of 2275 kW emits 0.7 gram/hp-hr NOx at 900 rpm, which is equivalent to 0.0009387 g/W-hr. For comparative illustration with alternative 1, if you assume …. As stated in the mitigation option; "Control Technology Options for Four Corners Power Plant" (FCPP), the NOx emission from FCPP is approximately 0.54 g/mmBtu. Based on the assumption that efficiency of FCPP is 40%, the NOx emission from FCPP is approximately 0.002099 g/W-hr. This comparison shows that the gas electrical generator is more environmentally friendly then using power from a coal based power plant. The baseline average emission for the Western Grid should be used to calculate the real emission difference between installing a lean burn electric generator to replace combustion engines.

The noise from continuously running internal combustion engines can be an issue for the nearby residents. The switch to electric motors will also help cut down the noise in the oil and gas operation.

The need for less maintenance of electric motors and lean burn electric generator will result in fewer maintenance trips for the oil and gas workers which will help in controlling dust as well minimize the impact on wild area in the four corners region.

Economics

The initial capitol cost of installing gas electrical generator and electrical motor would be relatively high. As an example, a generator of 1 MW capacity can approximately support 33 combustion engine of 40 HP. A general purpose 40 HP engines costs about $ 1200.00 which results in capital cost of $39,600 for replacing 33 internal combustion engine with electric motors. The approximate cost of a 1.2 MW gas-fired generator is $430,000. The total capital cost for replacing 33 engines with a gas fired generator will be about $470,000. However in long term the benefit in terms of emission reduction and saving in maintenance cost should help in recovering the initial capital cost.

The maintenance cost of one big generator is cheaper than maintenance of many smaller internal combustion engines.

The cost of running electrical wires to connect electric motors will much less than currently installed pipelines to carry natural gas for the small rich burn combustion engines.

Tradeoffs

In case of gas electric generators, there will be shift of emission from many internal combustion engines to one or several big internal combustion engine(s). There would be a net reduction in emissions which will depend on degree of conversion that each producer deems economically feasible.

The cost and affects of running transmission lines from generator(s) to power electrical motors for gas compression needs to be evaluated.

Burdens

The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary, depending upon the results of monitoring data over time.
B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies.

III. Feasibility of the option

A. Technical: The feasibility mainly depends on the close proximity of replaceable internal combustion engines and operating conditions of internal combustions engines in order of selection of gas electrical generator. The power, transmission line and substation requirements for on-site lean-burn generator system would need to be carefully considered in deciding the feasibility of this option.
B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Emissions from on-site electric generators would more than off-set the natural gas-fired engines that could be targeted for replacement (e.g., uncontrolled compressor engines or small rich burn pump jack engines).
C. Economic: Depends upon economics of ordering electrical motors, the ability of the grid system to supply the needed capacity and the cost to obtain right of way to drop a line to a potential site. Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small.

IV. Background data and assumptions used

The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff.

Gas electrical generator information was obtained from Caterpillar's Website.

V. Any uncertainty associated with the option (Low, Medium, High):

Medium based upon uncertainties of obtaining electrical easements from landowners and/or land management agencies.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups

Mitigation Option: Optimization/Centralization

I. Description of the mitigation option

Overview

- This option outlines the deployment of internal combustion engines used as the source to power various oil and gas related operations with the appropriate horsepower rated to the need of the activity being conducted. The advantages of this approach would be reducing the cumulative amount of horsepower deployed, which may reduce emissions through elimination of compression and optimization of compressor fleets. This may also be accomplished by using larger central compression in lieu of deploying numerous smaller compressor engines at a number of individual locations such as well sites.
- Overall fleets of engines in the San Juan basin are currently believed to be loaded at about 50% available hp. This is determined by looking at installed hp, volume of gas being moved, and pressure differentials in the field. These load factors are dynamic and constantly changing.
- **Differing opinion:** Emissions from compressor engines are based on the amount of fuel used (a function of capacity and load). Assuming that emission factors do not change with load (this may or may not be true), as the load is reduced emissions will decrease. If it is assumed that all engines have the same rate of emissions, simply reducing the number of engines and operating them at higher capacity will likely result in the same amount of fuel usage and the same amount of emissions. The assumption that all engines have the same emissions is not true and thus this option is based on a flawed premise. In reality, analysis of engine utilization in the region indicates that larger engines have lower emissions than smaller engines.

Air Quality and Environmental Benefits

- The benefits could be lower emissions calculated against horsepower assuming smaller horsepower engines would be deployed to replace larger engines. This would be accomplished by either design or as field conditions changed at individual sites or by centralizing compression horsepower at central site. While efficiency may improve, application of smaller engines working at or near full load may increase NOx emissions relative to an oversized unit operating at reduced load.
- **Differing opinion**: Needs to be framed for applicability to engine type, size, etc.

Economics

- Optimization:
  - The economics of replacing individual site compression with properly sized horsepower could be difficult. Some companies bought individual site compression based upon technical considerations at that time. Unfortunately, due to changing field conditions, which could not be contemplated when the original engine was bought, the existing engine may not be sized properly. To require the purchase of new compressors for changing field conditions over the life of a natural gas field will be an economic strain on the operators.
  - The salvage value of the compressor being replaced is a fraction of a new one.
  - Replacing engine compression several times during the life of well would not be economic. Purchasing new compression with operating conditions in a given field could jeopardize the economics of a well(s).
  - If the engines are rentals, the situation is much more flexible depending upon the lease/contract with the vendor. In the San Juan Basin most smaller well site

compression is a combination of purchased and leased, both of which depend upon the individual operator's preferences.

- Centralization
    - As with optimization, field conditions change and to size equipment properly on a horsepower basis may require numerous iterations of replacement.
    - As above with optimization, the economics of replacing units to fit ever changing field conditions in the cases where the equipment has been purchased will create economic challenges for the operators.
    - For leased units, flexibility would be greater, but would depend upon the lease/contract with the vendor.
    - Use of larger centralized engines increases the opportunity to use low emission lean burn engines.
- Lines and gathering system would probably need to be redesigned and replaced for efficiency, otherwise line losses and bottlenecking could create operation issues. Besides causing increased surface disturbance the economics of line redesign and replacement are probably beyond the economic feasibility limits of the fields in the area.

Tradeoffs

- The tradeoffs for centralization appear to have the most concern.
- There could be an air quality benefit by centralizing, but there would be more long-term surface disturbance involved and dust generation from construction. For instance, a central compressor serving multiple sites would likely need to be built at a new site making it more equitable from an operational perspective to serve its purpose. A new central site would then require surface disturbance for a new site and, whether an existing site could be used or not, underground piping from the central site to multiple sites would be necessary. This could result in permanent new disturbance (if a new site had to be built) and short-term disturbance for the pipeline to multiple sites until this was reclaimed.
- While above ground pipelines are a possibility, for safety reasons these have not been generally used in the San Juan Basin.
- Emissions tradeoffs based on relative operating loads would need to be considered.
- There is potential for increased noise for those living close to these centralized facilities.
- Potential for increased permitting.
- It is possible that centralized compressor stations would become Part 70 or 71 facilities (Title V under the CAA) and would require substantial testing and record keeping on the part of operators and agencies.

Burdens

- The burden for optimization and/or centralization would fall to industry. The cost of pursuing this approach should be carefully considered due to the impact it could have on the economic viability of a given well.
- Increased permitting places burden on regulatory agencies and industry.

<u>II. Description of how to implement</u>

A. Mandatory or voluntary. This option should be voluntary given the economic impacts.
B. Indicate the most appropriate agency(ies) to implement. NA; would be voluntary by the companies since they must assess the technical and economic feasibility.

<u>III. Feasibility of the option</u>

A. Technical: Technical concerns would include trying to size compression properly either with optimization or centralization considering the unknowns associated with changing field conditions.

B. Environmental: Potential environmental benefit would need to be more closely reviewed depending upon the specific scenario. At best, little or marginal benefits are likely to be realized.
C. Economic: While some centralized options could be considered, well-level optimization is not economically feasible considering all the variables that exist with field operations. .

IV. Background data and assumptions used
Discussions with company field and engineering staff

- Input from engine manufacturers and engine consultants

V. Any uncertainty associated with the option (Low, Medium, High)
High. For optimization: The sizing of engines is based on the maximum flow from a well. As wells decline through time the initial hp needs are no longer appropriate. Replacement of this existing hp would be cost prohibitive. For centralization: collection systems are already in place and centralizing would require retrofitting, which is cost prohibitive. Further, in NM, well sites and gathering systems have different owners. Competitors would need to collaborate to centralize, which would be unlikely.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups
None identified at this time. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Follow EPA New Source Performance Standards (NSPS)

I. Description of the mitigation option

EPA is in the process of developing the first national requirements for the control of criteria pollutants from stationary engines. Separate rulemakings are in process for compression-ignition (CI) and spark-ignition (SI) engines. These NSPS will serve as the national requirements, leaving states with the authority to regulate more stringently as might be required in unique situations.

CI NSPS: The final NSPS for stationary CI (diesel) engines was published in the Federal Register on July 11, 2006. It requires that new CI engines built from April 1, 2006, through December 31, 2006, for stationary use meet EPA's nonroad Tier 1 emission requirements. From January 1, 2007, all new CI engines built for stationary use must be certified to the prevailing nonroad standards. (Minor exceptions are beyond the scope of this discussion.)

SI NSPS: The NSPS proposal for stationary SI engines, including those operating on gaseous fuels, was published in the Federal Register on June 12, 2006. Per court order, the rule is to be finalized by December 20, 2007. Like the CI NSPS, certain elements of the SI NSPS will be retroactively effective once finalized. The following summarizes the proposed requirements:

EPA SI NSPS NPRM
NOx/CO/NMHC (g/bhp-hr)

		2007		2008		2009		2010		2011	
		1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul
All engines	≤ 25 hp			40 CFR 90							
Gasoline & RB LPG	26-499 hp			40 CFR 1048							
	> 500 hp		40 CFR 1048								
Natural gas & LB LPG											
Non-emergency	26-499 hp			2.0/4.0/1.0						1.0/2.0/0.7	
	≥ 500 hp		2.0/4.0/1.0						1.0/2.0/0.7		
Emergency	> 25 hp					2.0/4.0/1.0					
Landfill / digester gas	< 500 hp			3.0/5.0/1.0						2.0/5.0/1.0	
	≥ 500 hp		3.0/5.0/1.0						2.0/5.0/1.0		

Notes: [illegible]

All new stationary engines in the Four Corners region will have to meet the new EPA requirements. Deferring to the EPA NSPS will provide the most cost-effective emissions control because manufacturers will have compliant products for sale across much of the country. Compliance with the EPA NSPS will provide a level of emissions control that is federally mandated and will impose a certain financial burden that is not elective. The premise for this mitigation option is that additional control beyond the EPA NSPS would not be needed for new engines.

II. Description of how to implement

A. Mandatory: Compliance with the EPA NSPS will be mandatory. This would apply to all newly manufactured, modified and reconstructed engines after the NSPS effective dates. 'Modified' engines are those undergoing a change that would result in an increase in emissions, while 'reconstructed' engines are those undergoing rebuild work that costs at least 50% of the cost of a new unit. See 40 CFR 60.2 for further definitional details.

Differing Opinion: Voluntary: Applicability of the NSPS requirements could be considered for existing engines. Because a large number of existing engines would require extensive rework or replacement to achieve the NSPS levels, any such approach should be a voluntary, incentive-based program.

B. Indicate the most appropriate agency(ies) to implement**:** No additional work would be needed other than what EPA is mandating. Any permitting would continue to be at the State's discretion. The appropriate agencies for any incentive based applicability to existing engines would need to be determined.

III. Feasibility of the option

A. Technical: EPA has spent the past year working with engine manufacturers during its development of the CI and SI NSPS. The requirements have been shown to be technologically feasible.

B. Environmental: EPA's regulatory documents do/will provide details of the expected environmental benefits and the conclusion that this level of control is appropriate for areas not in advanced levels of non-attainment.

C. Economic: EPA's Regulatory Impact Analyses (RIA) for the two rulemakings will provide explanations of the expected costs of compliance.

IV. Background data and assumptions used

None beyond material in EPA's rulemakings.

V. Any uncertainty associated with the option (Low, Medium, High)

Essentially no uncertainty that the NSPS will soon provide new, emissions-controlled stationary engines in the Four Corners region.

VI. Level of agreement within the work group for this mitigation option

The RICE subgroup anticipates Oil & Gas Workgroup consensus that EPA's mandatory compliance with its new NSPS will provide appropriate short- and long-term emissions control that is commensurate with the needs of the Four Corners region.

VII. Cross-over issues to the other source groups

Assistance from Cumulative Effects Work Group needed to assess air quality benefits in the Four Corners area. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Adherence to Manufacturers' Operation and Maintenance Requirements

I. Description of the mitigation option

Engine manufacturers provide to end-users recommended procedures for the initial installation and adjustment of spark-ignition (SI) engines, in addition to on-going preventative maintenance recommendations. Adherence to these recommendations provides long-term, intended performance, emission levels, durability, etc. Please see EPA SI NSPS proposal update below under Section V.

II. Description of how to implement

A. Mandatory or voluntary: While adherence to engine manufacturers' 'recommended' procedures is generally voluntary from a regulatory perspective, this mitigation option instead proposes that such adherence be mandatory. This could be considered for existing engines as well as for new engines. Please see Section V below for further discussion.

B. Indicate the most appropriate agency(ies) to implement: EPA's proposed New Source Performance Standards (NSPS) for, in particular, SI engines, includes several related aspects that will likely be mandatory. Those aspects of engine manufacturers' recommended procedures that are not included in the NSPS could be implemented by the states.

1. 40 CFR 60.4234: **"Owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in 60.4233 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine."**

2. 40 CFR 60.4241(f): "Manufacturers may certify their engines for operation using gaseous fuels in addition to pipeline-quality natural gas; however, the manufacturer must specify the properties of that fuel and provide testing information showing that the engine will meet the emission standards specified in 60.4231(d) when operating on that fuel. **The manufacturer must also provide instructions for configuring the stationary engine to meet the emission standards on fuels that do not meet the pipeline-quality natural gas definition.** The manufacturer must also provide information to the owner and operator of the certified stationary SI engine regarding the configuration that is most conducive to reduced emissions where the engine will be operated on particular fuels to which the engine is not certified."

3. 60.4243: "**If you are an owner or operator, you must operate and maintain the stationary SI internal combustion engine and control device according to the manufacturer's written instructions** or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators of certified engines may only change those settings that are allowed by the manufacturer to ensure compliance with the applicable emission standards. ...The engine must be installed and configured according to the manufacturer's specifications to ensure compliance with the applicable standards."

4. 60.4245(a): **"Owners and operators of all stationary SI ICE must keep records of...maintenance conducted on the engine."**

III. Feasibility of the option

A. Technical: Prudent operators follow manufacturers' recommended procedures. Properly maintained engines operate more efficiently and at lower total cost. Ignition maintenance, in particular, can have significant impact on the performance and life of catalysts.

B. Environmental: Properly maintained engines produce lower emissions. Instead of a fix-as-fail mentality, proper maintenance can avoid or detect failed O_2 sensors or spark plugs, thus avoiding an increase in HC and CO.
C. Economic: The overall, long-term cost of a properly maintained engine is lower than that of a neglected engine.

IV. Background data and assumptions used

V. Any uncertainty associated with the option Medium. EPA NSPS Update: Mandatory requirement to follow engine manufacturers' recommendations is included in the proposal for optionally certified engines. For engines not certified by engine manufacturers, the owner/operator would have compliance responsibility and would not be required to follow the engine manufacturers' recommendations. Owner/operators are raising concern with EPA over the proposed requirement to follow engine manufacturer recommendations for certified engines or follow the proposed option to seek engine manufacturer approval for alternative operational procedures. Many owner/operators believe their own time-proven procedures are appropriate. Because EPA's final rule will have carefully considered the implications of operational and maintenance practices, the Agency's final outcome should be appropriate for new engines used in the Four Corners area. Any consideration of those requirements for existing engines would need to assess the potential benefits achievable through altering current field practices.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups

Mitigation Option: Use of SCR for NOx control on lean burn engines

I. Description of the mitigation option

NOx emissions from lean burn engines (natural gas and diesel fueled) can be reduced by chemically converting NOx into inert compounds. The most effective equipment to achieve NOx reductions is an SCR (selective catalytic reduction) system.
Differing opinion: SCR is one effective equipment option to achieve NOx reductions.
Reactant injection of industrial grade urea, anhydrous ammonia, or aqueous ammonia is required to facilitate the chemical conversion. The overall catalyst reaction is as follows:

$$NH_3 + NO + NO_2 > N_2 + H_2O$$

The SCR systems utilize programmable logic controller (PLC) based control software for engine mapping/reactant injection requirements. Sampling cells are utilized for closed loop feedback of dosing requirements depending on the amount of NO measured downstream of the catalyst bed.

SCR system components include catalyst housing, housing insulation, control/dosing panel, exhaust dosing/mixing section, and reactant injector. Depending on the reactant medium, a storage tank will be required with a potential minimum temperature requirement of 40°F. **Differing opinion:** Heated reactant storage may drive limited applicability. Description should be expanded to address handling, associated regulations with monitoring and testing for the system slip and RMPs if applicable. Electrical supply to run the SCR system and instrumentation is required.

SCR systems can be constructed with the addition of oxidation catalysts, for the added conversion requirements of CO, VOCs and Formaldehyde. This oxidation catalyst is a dry reaction and is not dependant on injection of a reactant. See the mitigation option on the use of oxidation catalysts for reduction levels achieved for the pollutants.
Differing opinion: Mitigation Option is 'Use of SCR for <u>NOx</u> control on lean burn engines'; therefore, this paragraph may be out of context.

II. Description of how to implement

<u>A. Mandatory or voluntary</u>
Voluntary: May be enhanced by the state supplementing a percentage of the cost.
<u>B. Indicate the most appropriate agency(ies) to implement</u>

III. Feasibility of the option

<u>A. Technical</u>: Dependent on site readiness, installation and start-up would require 7-10 days. **Differing opinion:** Heated reactant storage may drive limited applicability, especially if power is unavailable. Concerns include security risk, handling, safety standards, applicability of RMPs and other associated regulations for monitoring and testing of the system slip. There have been no known applications of this technology for remote unattended oil and gas operations. At the present time there is insufficient information to quantify achievable emission reductions in unattended facilities. The incremental cost to control on lean burn technology is likely to be very high because of the small incremental additional mass reductions as a result of tertiary add on controls. Because SCR uses a dilute aqueous solution, RMP hazards are typically not a concern.
Excessive ammonia slip within a coherent NOx plume may lead to increased NO_3 formation. This could result in degradation of visibility even though NOx emissions are reduced.

<u>B. Environmental</u>: Post catalyst NOx levels of <0.15g/bhp-hr.
Differing opinion: <0.15 g/bhp-hr depends on the start point but could imply 95% or greater control. Catalysts optimally start at 90-95% capability but drop over time. Control is sensitive and if it moves off

set point, result is 'no' control (vs. reduced control). What is the origin of the stated NOx levels? On what type of engine in what type of service? This appears to be simply an assertion with no backup or verification.

C. Economic: Cost of SCR system and maintenance are an increased cost to the packager and end user. The five-year cost for SCR on a 3-engine rig in the Jonah/Pinedale area of Wyoming was estimated at $5 MM in a demonstration pilot conducted by Shell. This information is available from the Wyoming DEQ.
Differing opinion: Costs of heated storage, additional regulatory compliance, added manpower and increased site security would be the burden of the operator. In addition, the engine must be highly stable for this control to be effective (see environmental note).
See also Cumulative Effects Analysis for this option for further emissions analysis.

IV. Background data and assumptions used

V. Any uncertainty associated with the option (Low, Medium, High)
Medium. Negative perception of reactant handling and injection, though the technology has proven itself to be very user friendly.
Differing opinion: HIGH: The assertion that this is "user friendly" technology is not aligned with the experiences documented as part of the pilots noted above. In these pilots, the systems required both a vendor representative and consultant on site to keep them operating correctly. Concerns include heating reactant, security risk, handling, safety standards, applicability of RMPs and other associated regulations for monitoring and testing of the system slip.
Modeling needs to be conducted to evaluate the potential improvement in ambient air quality (ozone, deposition and visibility).

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups (please describe the issue and which groups) None.

Differing opinion: The CE group needs to offer an opinion on the effect of additional ammonia emissions at plume height.

See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Use of NSCR / 3-Way Catalysts and Air/Fuel Ratio Controllers on Rich Burn Stoichiometric Engines

I. Description of the mitigation option, including benefits (air quality, environmental, economic, other) and burdens (on whom, what)

NO_X, CO, HC, and Formaldehyde emissions from a stoichiometric engine can be reduced by chemically converting these pollutants into harmless, naturally occurring compounds of nitrogen, carbon dioxide and water vapor. The most common method for achieving this is through the use of a catalytic converter. In a catalytic converter, the catalyst will either oxidize (oxidation catalyst) a CO or fuel molecule or reduce (reduction catalyst) a NO_X molecule. The general catalyst reactions are as follows:

$$NO + CO = N_2 + CO_2$$
$$NO_X + CH_4 = N_2 + CO_2 + H_2O$$
$$NO_X + H_2 = N_2 + H_2O$$

These reactions are reducing the NO_X to nitrogen and oxidizing the fuel and CO molecules. These reactions oxidize some of the CO and NMHC molecules, however further conversion is accomplished with and oxidizing catalyst. The oxidizing reactions are shown below:

$$CO + O_2 = CO_2$$
$$CH_4 + O_2 = CO_2 + H_20$$
$$CnHm + O_2 = CO_2 + H_20$$
$$H_2 + O_2 = H_2O$$

A 3-way catalyst contains both reduction and oxidation catalyst materials and will convert NO_X, CO, and NMHCs to N_2, CO_2, and H_2O. A process which causes reaction of several pollutant components is referred to as a Non Selective Catalyst Reduction (NSCR). NSCR is applicable only on stoichiometric engines. A very narrow air/fuel ratio operating range is necessary to maintain the catalyst efficiency. This can only be consistently maintained by utilizing electronic air/fuel ratio controls.

Maintaining low emissions in a stoichiometric combustion engine using exhaust gas treatment requires a very closely regulated air/fuel ratio. Without an air/fuel ratio controller, emission reduction efficiencies vary through the catalyst. Many Air/Fuel Ratio Controllers (AFRCs) are available on the market today. AFRCs are available from both the engine manufacture or can be purchased from an after-market supplier. Most controllers utilize closed loop control based on the readings of an exhaust gas oxygen sensor to determine the air/fuel ratio.

Air/Fuel Ratio Control will only maintain an operator-determined set point. For this set point to be at the lowest possible emissions setting an exhaust gas analyzer must be utilized. Operators should utilize quarterly emission tests to ensure units are maintaining compliance.

Differing opinion: This mitigation option is distinct from the mitigation option on using oxidation catalysts on lean burn engines because NSCR controllers are applied only to rich burn engines. Only applies to true rich burn engines, not effective for 1-2% rated rich-burns. 3-way catalysts are only applicable to stoichiometric (true rich burn) engines, potential is to drive the exhaust temperature up. Oxygen, oil slip past engine rings, and poor fuel quality may destroy the catalysts.

II. Description of how to implement

A. Mandatory or voluntary:

Voluntary: May be enhanced by state funding a percentage of the cost.

Mandatory: Mandatory enforcement would give the state the power to eliminate, at the minimum, 90% of NO_X, CO, HC, and Formaldehyde emissions from stationary elements.
Differing Opinion: This option should be mandatory, implemented and enforced by the states.
Differing Opinion: 90% is a reasonable not minimum control for NOx and CO, but HC and Formaldehyde are not straightforward to measure or to define. Catalysts are in a constant state of decline during operation and require periodic cleaning or replacement. 90% control is contingent on closely monitored and regulated air/fuel ratio. A more likely/achievable reduction of NOx is in the 80% range and can only be achieved with well operated and maintained engines/AFR's where the load is stable in nature. Variable loads result in less than optimum air/fuel ratios and less reduction.

B. Indicate the most appropriate agency(ies) to implement: States, Tribes and/or BLM, due to the fact that they are already involved in air quality regulations.
Differing opinion: Mandatory implementation of this requirement would only be feasible in a well-crafted permit program administered by the agency having jurisdiction for air quality. BLM does not have regulatory authority for air quality. Although Tribes may have air quality administration authority, very few functional Tribal programs currently exist.

III. Feasibility of the option
A. Technical: Engines can be retrofitted in the field ½ a day or less. Catalysts do have a life span and will lose their efficiencies. However, under ideal operating parameters and with consistent engine maintenance, the life span of a catalyst can easily be up to 5 years. Catalysts can be washed to increase the lifespan in the case of oil spray or ashing. AFRC oxygen sensors should be replaced quarterly to assure constant compliance. Fuel quality limitations are notable, i.e. field gas, biofuel, etc. may damage catalysts.
Differing Opinion: The previous statement is inaccurate; if an engine can be retrofitted, the exhaust system has to be dismantled and rebuilt. Not all engines will accept an after-market add on of AFRC. Usually, the added controls require a new base, piping and if applicable, tear down and modification of protective building/fencing. If the engine is portable/skid mounted, this may prohibit it remaining portable. Retrofit installation of catalyst housings and units typically require additional support structure.

B. Environmental: Minimum of 90% NO_X, CO, HC, and Formaldehyde emission reduction. Some increase in ammonia emissions would result, however, it is not known if this increase would be significant.
Differing opinion: 90% is a reasonable not minimum control for NOx and CO, but HC and Formaldehyde are not straightforward to measure or to define. Catalysts are in a constant state of decline during operation and require periodic cleaning or replacement. 90% control is contingent on closely monitored and regulated air/fuel ratio. A more likely/achievable reduction of NOx is in the 80% range and can only be achieved with well operated and maintained engines/AFR's where the load is stable in nature. Variable loads result in less than optimum air/fuel ratios and less reduction. Issues Associated With the Use of NSCR on Existing Small Engines:

- Engines Operate at Reduced Loads and There is a Problem Maintaining Sufficient Stack Temperature for Catalyst to Work
- On Engines with Carburetors, Difficulty Having the AFR Maintain a Proper Setting
- On Older Engines the Linkage and Fuel Control May not Provide "Fine Enough" Control
- If the AFR Drifts Low, NH_3 Will be Formed in Roughly Equal Amounts to NOx Reduced

C. Economic: The cost of catalyst and AFRC are an added cost to both packager and end user, however, as technologies have advanced, producers have a number of cost effective options. The fact of the matter is the cost to the producer to maintain compliance is much greater than the cost of a catalyst or AFRC. In order to maintain compliance of any kind, the producer is forced to have more manpower, more thorough engine maintenance programs, and adequate testing of their units to assure that they are in constant compliance. Caterpillar recommends monthly testing with portable analyzer. See approximate control cost analysis as of January 2007 for an example of the cost of NSCR control.

	NSCR Retrofit Costs		
	Compressco Ford 460	Wauk. 220/330	Comments
Catalyst Housing Purchase	*$2,120*	*$1,600*	
Catalyst Housing Purchase w/Silencer	*$2,650*	*$1,950*	
Average Housing Purchase	*$2,385*	*$1,775*	
Catalyst Element Purchase	*$1,000*	*$800*	
Air Fuel Ratio Controller Purchase	*$2,950*	*$2,950*	
"Rebuild" of Fuel and Air Control System on Older Engines			
Electricity for Air Fuel Ratio Controller - Purchase of solar power unit	*$350*	*$350*	*Alternator and Battery or Solar and Battery*
Installation of Housing and Catalyst	*$1,080*	*$1,080*	*Assumes one welder and one helper for one full day*
Installation/Modification of Support for Housing and Exhaust	*$300*	*$300*	*Estimate of materials - Labor in item above*
Installation of Electricity	*$540*	*$540*	*Electrician or Mechanic for 1/2 day - includes travel to and from*
Installation and Set-up of Air Fuel Ratio Controller	*$2,160*	*$2,160*	*Electrician or Mechanic and Instrument Technician for one day - includes travel time to and from*
Incremental Skid Cost for New Engine	*$1,000*	*$1,000*	
Taxes, Freight, Etc. (From EPA Manual)	*$1,077*	*$1,077*	
Total Purchase and Installation - Retrofit	*$11,842*	*$11,032*	
Total Purchase and Installation - New	*$8,225*	*$7,415*	
Maintenance Cost			
Quarterly Change of O2 Sensor + Emissions Monitoring - annual cost	*$320*	*$320*	
Labor/Travel for Above	*$540*	*$540*	*Technician for 1/2 day - includes travel to and from*
Annualized Catalyst Replacement (5 yr life)	*$160*	*$160*	
Total Annual Cost	*$1,020*	*$1,020*	

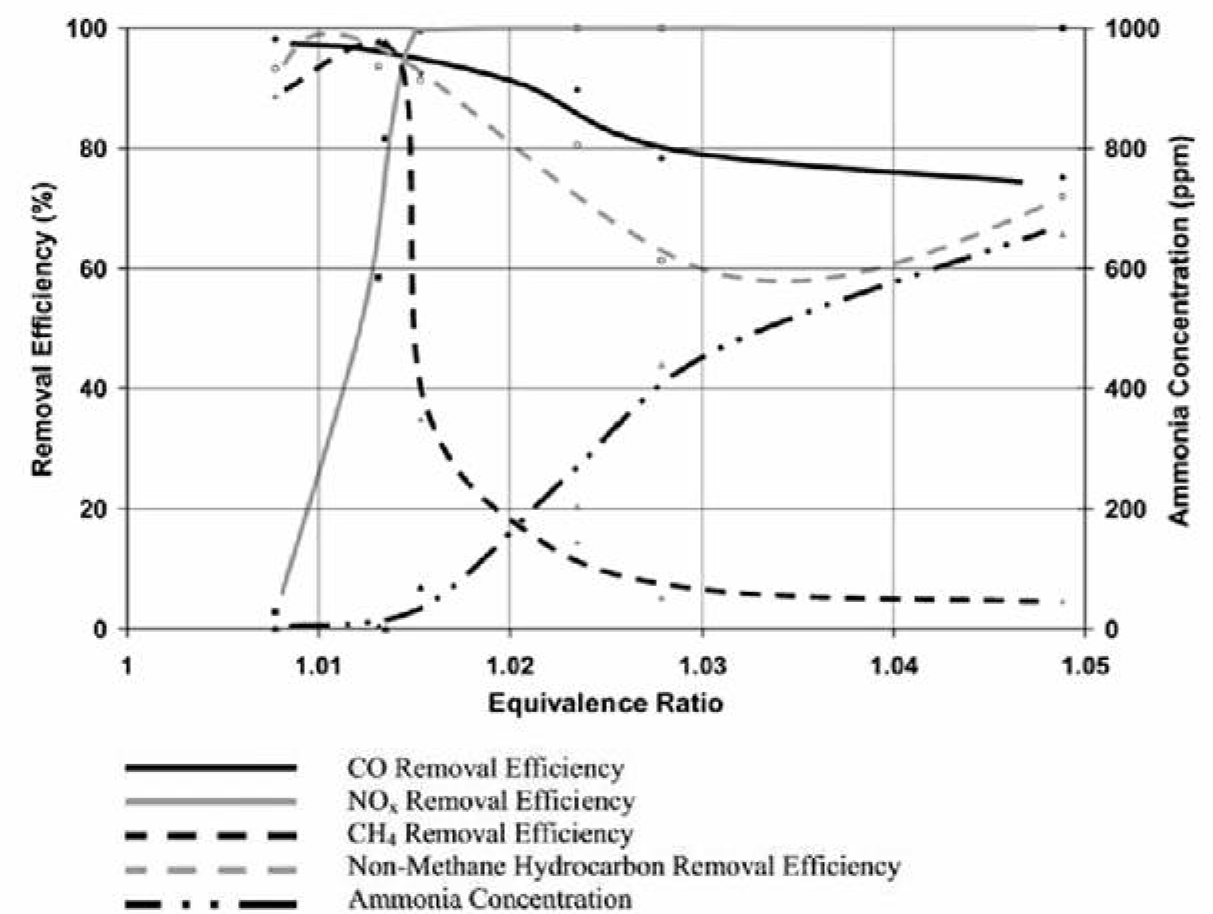
IV. Background data and assumptions used

1. G. Sorge "Update on Emissions"
Differing opinion: Insufficient information to locate reference.

V. Any uncertainty associated with the option (Low, Medium, High)

LOW, this is a proven technology with years of results. One issue of merit is the production of ammonia through a 3-way catalyst. This issue has been thoroughly researched and the following are the generalized results:
Differing Opinion: MEDIUM: HC is difficult to measure. Drift of control and narrow applicability to only 'true' rich burn engines are significant issues.

The problem of NH3 formation across catalyst equipped rich burn CNG engines is associated with problems of the A/F controllers. If the A/F ratio is allowed to drift rich, considerable NH3 can be formed. This is shown in the following graph:



Differing opinion: Reference is needed for the Graph credentials.

For a variety of reasons the A/F controllers have failed to control at the desired set point, 0_2 sensors failing, a not particularly sophisticated controller, etc. Today's AFRCs are very exact machines with the ability to easily maintain a precise set point. If a rich burn engine is operated with a properly functioning air/fuel ratio controller plus 3-way catalyst, it will meet emissions requirements without producing a noticeable amount of ammonia.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups None at this time.
Differing Opinion: The CE group needs to offer an opinion regarding the impact of increased ammonia emissions in the region. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Use of Oxidation Catalysts and Air/Fuel Ratio Controllers on Lean Burn Engines

I. Description of the mitigation option

CO, HC, and Formaldehyde emissions from a lean burn engine can be reduced by chemically converting these pollutants into harmless, naturally occurring compounds, such as carbon dioxide and water vapor. Lean Burn Engines already have low uncontrolled NO_X emission values (Lean burn engines are a form of NOx control and therefore do not have uncontrolled emissions). The most common method for achieving this is through the use of a catalytic converter. In a catalytic converter, the oxidation catalyst will oxidize (oxidation catalyst) a CO or fuel molecule. The most common method for achieving CO, HC and formaldehyde control this is through the use of an oxidation catalytic converter. The general oxidizing reactions are shown below:

$$CO + O_2 = CO_2$$
$$CH_4 + O_2 = CO_2 + H_20$$
$$CnHm + O_2 = CO_2 + H_20$$
$$H_2 + O_2 = H_2O$$

Air/fuel ratio control helps to maintain the catalyst efficiency. This can only be consistently maintained by utilizing electronic air/fuel ratio controls. However, most air/fuel ratio controllers are utilized to maintain engine performance due to ambient conditions. While it is true that lean burn engines perform better with AFRC units they are not needed for oxidation catalyst performance – the exhaust stream in a lean burn engine has sufficient oxygen under all conditions where the engine will run.
Differing opinion: An electronic air/fuel ratio controller is recommended to help maintain the catalyst efficiency.

Maintaining low emissions in a lean combustion engine using exhaust gas treatment is enhanced by the use of an Air/Fuel Ratio Controller, however, not necessary. Many Air/Fuel Ratio Controllers (AFRCs) are available on the market today, from both the engine manufacture in certain cases and after-market suppliers. Most controllers utilize closed loop control based on the readings of an exhaust gas oxygen sensor to determine the air/fuel ratio.

Air/Fuel Ratio Control will only maintain an operator-determined set point. For this set point to be at the lowest possible emissions setting an exhaust gas analyzer must be utilized. Operators should utilize quarterly emission tests to ensure units are maintaining compliance.

Differing opinion: The preceding two paragraphs seem out of place in the context of oxidation catalyst.

II. Description of how to implement

A. Mandatory or voluntary**:**
Voluntary: May be enhanced by state funding a percentage of the cost.
Mandatory: Mandatory enforcement would require give the state the power to eliminate, at the minimum, 90% of CO, HC, and Formaldehyde emissions from stationary elements. Lean Burn Engines already have low uncontrolled NO_X emission values.
Differing Opinion: This option should be mandatory, implemented and enforced by the states.
Differing Opinion: 80% CO destruction is a more likely/sustainable reduction for CO and HC's. Formaldehyde destruction/control is less certain but is lower than CO or HC's.
Differing Opinion: 90% is a reasonable not minimum control for CO; but HC and Formaldehyde are not straightforward to measure or to define. Catalysts are in a constant state of decline during operation and require periodic cleaning or replacement. 90% control is contingent on closely monitored and regulated air/fuel ratio.

<u>B. Indicate the most appropriate agency(ies) to implement</u>**:** States, Tribes and/or BLM, due to the fact that they are already involved in air quality regulations.
Differing Opinion: BLM is not appropriate since they are not charged with air quality management. This is the role and responsibility of the States or Tribes.

<u>III. Feasibility of the option</u>
<u>A. Technical</u>**:** Engines can be retrofitted in the field ½ a day or less. Catalysts do have a life span and will lose their efficiencies. However, under ideal operating parameters and with consistent engine maintenance, the life span of a catalyst can easily be up to 5 years. Catalysts can be washed to increase the lifespan in the case of oil spray or ashing. AFRC oxygen sensors should be replaced quarterly to assure constant compliance.
Differing Opinion: The previous sentence should be deleted – it is not applicable to oxidation catalyst.
Differing Opinion: The previous statement is inaccurate; <u>if</u> an engine can be retrofitted, the exhaust system has to be dismantled and rebuilt. Not all engines will accept an after-market add-on of AFRC. Usually, the added controls require a new base, piping and if applicable, tear down and modification of protective building/fencing. If the engine is portable/skid mounted, this may prohibit it remaining portable. Typically, retrofit will require additional support structure for the
<u>B. Environmental</u>**:** Minimum of 90% CO, HC, and Formaldehyde emission reduction.
Differing Opinion: 90% is a <u>reasonable</u> not minimum control for CO; but HC and Formaldehyde are not straightforward to measure or to define. Catalysts are in a constant state of decline during operation and require periodic cleaning or replacement. 90% control is contingent on closely monitored and regulated air/fuel ratio.

According to the EPA speciate database, the majority of HC emissions from RICE are methane (C1), which is not a regulated pollutant under the Clean Air Act. Methane is unregulated because it does not enter into photochemical reactions that form ozone. Therefore, from a THC or more importantly a VOC perspective, such controls will do little to improve ambient air quality. Realistic modeling analyses that focus on population exposure should be performed to evaluate exposure to formaldehyde. 80% CO and HC reduction is more likely in an operational mode. HCHO destruction is not completely understood but is lower than CO or HC.
<u>C. Economic</u>**:** The cost of catalyst and AFRC are an added cost to both packager and end user, however, as technologies have advanced, producers have a number of cost effective options. The fact of the matter is the cost to the producer to maintain compliance is much greater than the cost of a catalyst or AFRC. In order to maintain compliance of any kind, the producer is forced to have more manpower, more thorough engine maintenance programs, and adequate testing of their units to assure that they are in constant compliance.

<u>IV. Background data and assumptions used</u> 1. G. Sorge "Update on Emissions"
Differing opinion: Insufficient information to locate reference

<u>V. Any uncertainty associated with the option (Low, Medium, High)</u> LOW, this is a proven technology with years of results.
Differing Opinion: The uncertainty is not in the emission reduction technology. The uncertainty is in the ambient air quality benefits that would be achieved as a result of implementation of this option.

<u>VI. Level of agreement within the work group for this mitigation option</u> TBD

<u>VII. Cross-over issues to the other source groups</u> None at this time. See also Cumulative Effects Analysis for this option for further emissions analysis.

Mitigation Option: Install Lean Burn Engines

I. Description of the mitigation option

Using gas fueled (reciprocating) **Lean Burn Engines** as the main prime mover in gas compression and generator set applications in the Four Corners area.

Gas engines are the predominant prime mover used to power gas compressor packages. Gas engines are classified as either Rich Burn or Lean Burn. The industry acknowledges a lean burn engine to have an oxygen level measured at the exhaust outlet of about 7-8%. This typically translates into a NOx emissions rating of 2 g/bhp-hr or less. This will be federally mandated through NSPS regulations requiring performance at this rating for both Lean Burn and Rich Burn engines. Currently, a large percentage of engines operating in the Four Corners Area that have a capacity of greater than 500 hp use lean burn technology and achieve, on average, a NOx emission rating of less than 2 g/hp-hr.

Lean burn engines have this lower NOx rating without using a catalyst or any other form of emissions after-treatment. Some lean burn engine incorporate an Air Fuel Ratio Control installed at the engine manufacturing plant.

Typically lean burn engines have a HP rating above 300 HP. This reflects today's manufacturing emphasis.

The main advantage of using a lean burn is in its capability to offer low emissions without after-treatment. In addition, lean burn engines operate at cooler temperatures and may offer longer life between major repairs.

II. Description of how to implement

A. Voluntary – lower emissions should be the goal. How the operator gets there is his selection and responsibility. In other words, allow an operator to either use a lean burn engine without emissions after-treatment or a rich burn engine with emissions after-treatment to achieve the emissions level needed. It is important to note that the majority of engines greater than 500 hp located on the Southern Ute Reservation where there is no minor source permitting program are lean burn or are low emitting engines as a result of post catalyst treatment. This has been a voluntary effort from the operators.
B. Most appropriate agency to implement: EPA and state air boards.

III. Feasibility of the option

A. Technical: Some states have shown preference to accept engines with lean burn technology over rich burn engines using after-treatment. But as of mid-2006 no engine manufacturers offer the lean burn engine at less than 300 HP. So manufacturers would have to develop a new engine to meet this requirement.
B. Environmental: Study the effect of HAPs formation in lean burn emission and whether further reduction is necessary. There has been extensive testing on HAP emissions from lean burn engines and EPA has established MACT standards for major HAP sources that pertain to RICE. Realistic modeling analyses that focus on population exposure should be performed to evaluate exposure to formaldehyde. The consolidated engine rule for SI engines will require HCHO control.
C. Economic: This is the best economic solution when the power rating is available and the total emissions for all pollutants meet the requirement. Typically this is a more economically viable solution than having a rich burn engine with added controls, catalysts and air to fuel ratio.

IV. Background data and assumptions used

Since there are no known lean burn engines under 300 hp, engine manufacturers may be interested in developing them. The development of these engines may be the most acceptable solution to users, EPA, and states. The forthcoming NSPS will encourage engine manufacturers to develop lean burn engines under 300 hp.

V. Any uncertainty associated with the option (Low, Medium, High)

The uncertainty is not in the lean burn technology but in the ability to meet the air emission requirement across all hp ratings (from 25 - 425 hp) and the acceptance of the final composition of the exhaust gases (including HAPs).

Manufacturers are not unwilling to create new technologies but there is a risk associated with the types of investment returns on technologies developed for small engines.

VI. Level of agreement within the work group for this mitigation option

Some believe that after-treatment is the best option. This is acceptable to an engine manufacturer but this option adds cost related to the additional equipment needed, permitting and monitoring process. In addition, there is the suspicion that engines with after-treatment may be working out of compliance at any one point.

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

A study should be conducted on what would achieve the lowest emissions:

- lean burns with no after-treatment
- lean burns with oxidation catalysts and AFRs
- or rich burns with catalysts and AFRs.

From the results, select the option that produces the lowest emissions.

Mitigation Option: Interim Emissions Recommendations for Stationary RICE

I. Description of the mitigation option

The following mitigation option paper is one of three that were written based on interim recommendations that were developed prior to the convening of the Four Corners Air Quality Task Force. Since the Task Force's work would take 18-24 months to finalize, and during this time oil and gas development could occur at a rapid pace, an Interim Emissions Workgroup made up of state and federal air quality representatives was formed to develop recommendations for emissions control options associated with oil and gas production and transportation. The Task Force includes these recommendations as part of its comprehensive list of mitigation options.

Require a 2 g/bhp-hr limit on engines less than 300 HP:

- May lead to 60 to 80 percent reduction in NOx.
- Help with visibility impairment in Class I areas in four corners region. Monitoring data at Mesa Verde and Weminuche Class I Areas clearly shows that NOx (NO3) is responsible for a very small fraction of visibility impairment. Modeling studies using the EPA CALPUFF model suggest that NO3 is responsible for visibility impairment in the Class I Areas. There are numerous examples that demonstrate that CALPUFF significantly over estimates NO3 visibility impairment compared to monitoring data.
- Several manufacturers offer engines that meet this specification, commercially available in two stroke engines only. Four stroke Lean burn engines capable of meeting 2 g/bhp-hr are not yet commercially available in sizes < 300hp.
- NSCR catalytic reduction can be added at reasonable cost. Potential engine durability concerns associated with elevated exhaust temperatures must be addressed when considering reasonable costs of installation of NSCR.
- Ammonia emissions may increase from use of NSCR catalyst.
- Increased ammonia may or may not affect visibility in the region.
- Without implementation, air quality standards may be exceeded.

Require a 1 g/bhp-hr limit on engines larger than 300 HP:

- Lean burn technology is widely available from manufacturers.
- The lean burn technology will help protect visibility in the region.
- The NAAQS and PSD increments will be less affected.
- Deposition of NOx and related compounds would be reduced
  Differing Opinion: Analysis of engine quarterly flue gas testing results indicates that, on average, it is possible to achieve an emission limit of 1 g/hp-hr, however, it may not be possible to achieve this emission level on a continuous basis.

II. Description of how to implement

These limits should be mandatory for all new and relocated engines and potentially for existing engines as well. The most appropriate agencies to implement this would be the FLMs and the New Mexico, Colorado and Southern Ute environment departments.

Existing fleet has limited compressors that meet these performance criteria. Based on NMAQ Letter of Instruction dated August 2005, <300 hp compressors must meet 2g/hp-hr. It should be noted that BLM does not have air quality authority to require any particular emissions performance from engines. This should be implemented through a well crafted minor source permit program administered by the air quality agencies.

Implementation Status for this Mitigation Option
BLM in New Mexico is currently requiring compressor engines 300 horsepower or less to have NOx emissions limited to 2 grams per horsepower hour as a Condition of Approval for their Applications for Permit to Drill. Effective August 1, 2005, BLM New Mexico, Farmington Field Office (FFO) started adding to each APD issued on and after this date a Condition of Approval (COA) requiring a limit on NOx emissions if operator placed a compressor on the location. The specific condition language states the following:

> This permit is contingent on compliance with the New Mexico Environmental Department, Air Quality Bureau's directive that compressor engines 300 horsepower or less have NOx emissions limited to 2 grams per horsepower hour.

This was based on correspondence received by the NM Air Quality Bureau dated June 3, 2005 and June 5, 2005. The FFO developed the language for the COA, which was reviewed by the NM Air Quality Bureau. The operators are required to comply with this COA regardless of whether it is a newly built compressor or a compressor that they bring in from another location or their ware yard and regardless of when the operators places the compressor on the location (i.e. six months later or two years later etc.).

BLM and USFS permits in the Northern San Juan Basin in Colorado involving new and replacement stationary internal combustion gas field engines require the following emission limits, on an interim basis:

- Emission Control (small gas field engines): All new and replacement internal combustion gas field engines of less than or equal to 300 design-rated horsepower must not emit more than 2 grams of nitrogen oxides (NOx) per horsepower-hour. This requirement does not apply to gas field engines of less than or equal to 40 design-rated horsepower.

- Emission Control (large gas field engines): All new and replacement internal combustion gas field engines greater than 300 design-rated horsepower must not emit more than 1.5 gram of NOx per horsepower-hour.

Interim NOx emission requirements for permits on other BLM and USFS lands in southwestern Colorado have not been established at this time. It is expected that NOx emission requirements will be implemented for these areas in the near future, either as a result of several ongoing planning efforts, or on an interim basis until these planning documents are completed.

Interim NOx emission requirements have not been established for gas field engines on the Southern Ute Indian Reservation at this time. Discussions between the Southern Ute Indian Tribe, State of Colorado Environmental Commission, US EPA Region 8, BLM and BIA are ongoing, and it is expected that NOx emission requirements will be implemented for this area in the near future.

III. Feasibility of the Option
The feasibility of a 2 g/bhp-hr limit has been demonstrated and equipment is commercially available. The economic feasibility is acceptable for new engines since the equipment is somewhat more expensive. Economic feasibility is acceptable for many new engines since the equipment is somewhat more expensive.
Differing Opinion: A number of new and existing engines cannot accept NSCR due to potential durability concerns associated with elevated exhaust temperatures during the needed stoichiometric operation, especially at low or varying loads.
The technical feasibility of a 1 g/bhp-hr limit has been demonstrated in commercial applications. The environmental benefits are significant. New lean burn engines can achieve this emission limit with no add-on controls, and rich burn engines can utilize add-on controls to achieve this limit. The cost is

acceptable given the large amounts of gas being compressed by these engines. **Differing Opinion:** The previous statement is subjective and unsubstantiated without supporting data. Need cost benefit analysis to determine acceptable levels. Only the new generation of lean burn engines are capable of meeting a 1 gram performance and then only with AFRC units and near full load.

IV. Background data and assumptions used

The 2 g/bhp-hr limit is based on existing engine technology in conjunction with an NSCR catalyst. The assumptions are that these engines are more than 40 HP and less than 300 HP and that they are natural gas fueled. Further, these engines would be operated with an air fuel ratio controller. The technology for the 1 g/bhp-hr engines larger than 300 HP in natural gas is well established. Although the technology is well established, it will not be commercially available for all engines until 2010. There are large engines available that have a vendor guarantee of emissions approaching 1 g/hp-hr, however, the issue is maintaining emissions at this level on a continuous basis. The new generation lean burn engines in larger sizes will meet 1 g/bhp-hr performance if equipped with AFRC units and operated near full load.

V. Any uncertainty associated with the option

The uncertainty associated with this option is the potential formation of ammonia emissions as a result of add-on controls. Ammonia emissions could worsen the air quality in the region. (See ammonia monitoring mitigation option paper.]

VI. Level of agreement within the work group for this mitigation option TBD.

Differing Opinion: EPA has proposed a 1.0 g/bhp-hr NOx limit for new SI engines, $\geq$ 500 hp, built on or after July 1, 2010, and for new SI engines, 26-499 hp, built on or after January 1, 2011. While these potential requirements are not expected to be finalized until December 20, 2007, engine manufacturers have already had to initiate engineering work in anticipation of this 1.0 gram requirement. Although a number of lean-burn engines can meet this requirement now, EPA chose the effective dates based upon the fact that other lean-burn engines need the additional time to meet the standards. Cummins has initiated significant work requiring significant resources to modify those engines to achieve the forthcoming 2.0 g/bhp-hr NOx standard. Cummins believes that the incremental benefit offered by a potential pull-ahead of the 1.0 gram standard for larger engines versus the EPA requirement for 2.0 grams NOx soon to be effective followed by the 1.0 gram standard three years later would likely be difficult to justify. Such a pull-ahead, without sound justification, would undermine the substantial work being done by EPA and engine manufacturers in moving toward a national requirement that is to avoid similar, yet different, requirements.

VII. Cross-over issues to the other source groups

The cumulative effects and monitoring groups need to address the concerns with ammonia emissions.

Mitigation Option: Next Generation Stationary RICE Control Technologies – Cooperative Technology Partnerships

This option paper investigates the status of five (1-5) new and/or evolving emissions-control technologies. They are: laser ignition, air-separation membranes, rich-burn engine with three-way catalyst, lean-burn NOx catalyst, and Homogeneous-Charge Compression-Ignition (HCCI) Engine.

Laser ignition is under development in the laboratory, but it has not reached a point where technology transfer viability can be determined.

Air separation membranes have been demonstrated in the laboratory, but have not been commercially available because the membrane manufacturers do not have the production capacity for the heavy-duty trucking industry. Since stationary engines are a smaller market, there is a high probability that the membrane manufacturers could ramp up production in this area.

Rich-burn engines with three-way catalysts borrow from the well-developed automobile industry. It is applicable to smaller engines for which lean-burn technology is not available.

There are several variations of lean-burn NOx catalysts, but the one of most interest is the NOx trap. NOx traps are being used primarily in European on-road diesel engines, but are expected to become common in the U.S. as low-sulfur fuel becomes available. Applicability to lean-burn natural-gas engines is possible but it will require a fuel reformer to make use of the natural gas as a reductant.

1. Laser Ignition

<u>I. Description of the mitigation option</u>

Overview

Laser ignition replaces the conventional spark plugs with a laser beam that is focused to a point in the combustion chamber. There, the focused, coherent light ionizes the fuel-air mixture to initiate combustion. Applicability is primarily to lean burn engines, although laser ignition could be applied to rich burn engines. Compared to rich-burn engines, lean burn engines, which are significantly more efficient, require much higher ignition voltage with spark plugs, whereas it takes lower ignition energy with laser system.

Advantages of laser ignition compared to spark plugs include: 1. Longer intervals between shutdowns for maintenance because wear of the electrodes is eliminated, 2. More consistent ignition with less misfiring because higher energy is imparted to the ignition kernel, 3. The ability to operate at leaner air-fuel mixtures because higher energy is imparted to the ignition kernel, 4. The ability to operate at higher turbocharger pressure ratio or compression ratio because the laser is not subject to the insulating effect of high-pressure air - air at higher pressure requires a higher voltage to make the spark jump the gap, and, 5. Greater freedom of combustion chamber design because the laser can be focused at the geometric center of the combustion chamber, whereas the spark plug generally ignites the mixture near the boundary of the combustion chamber.

However, laser ignition has some unresolved research issues that must be resolved before it can become commercially available. These include: 1. Lasers are intolerant of vibration that is found in the engine's environment. 2. Some means of transmitting the laser light to each combustion chamber should be developed while accommodating relative motion between the engine and the laser. This might be done with mirrors or with fiber optics. Fiber optics generally lead to a simpler solution to the problem. 3. Current fiber optics is limited in the energy flux they can transmit. This leads to a less-than-optimum energy density at the focal point. 4. Wear of the fiber optic due to vibration may limit its lifetime. 5. The cost of a laser is such that multiple lasers per engine are too expensive. Therefore, a means of distributing the light beam with the correct timing to each cylinder must be developed.

Air Quality and Environmental Benefits

Although laser ignition could be applied to rich burn engines, environmental benefits would accrue to lean burn engines. Air quality and environmental benefits are difficult to quantify at the current state of development. The more consistent ignition compared to spark ignition can be expected to decrease emissions of unburned hydrocarbons. The ability to operate at leaner air-fuel ratios and at higher turbocharging pressure is expected to decrease emissions of NOx because of lower combustion temperatures. Laser ignition systems have not been developed to the point where the effect of improved combustion chamber design can be measured. It is reasonable to expect that a better combustion chamber design would further decrease emissions of unburned hydrocarbons, carbon monoxide, and NOx. In actual operation of the engine, misfiring of one or more cylinders contributes to loss in efficiency and increase in emissions. With the laser ignition system, misfiring can be virtually eliminated. It is estimated that with laser ignited lean burn engines, the regulated levels of California Air Resources Board NOx levels can be met.

Economic

The primary advantage of laser ignition is its potential to eliminate downtime due to the need to change spark plugs. This advantage would accrue to both rich burn engines and lean burn engines. Higher efficiency due to near elimination of cylinder misfirings is an additional benefit.

Trade-offs

A tradeoff for engine manufacturers, assuming that laser ignition can be developed to the point of commercial feasibility, is whether or not to develop retrofit kits. Retrofits would be expected to take away sales of new engines.

A tradeoff for engine users is whether to continue using spark ignition or to purchase a laser ignition that is initially more expensive but has a future economic benefit.

Another tradeoff for engine users is whether to retrofit laser ignition to an existing engine or to spend more money for a new engine in return for future benefits.

<u>II. Description of how to implement</u>

A. Mandatory or voluntary: Implementation should be voluntary because the primary incentive for implementation is economic.
B. Indicate the most appropriate agency(ies) to implement: At the current state of development, a research organization is the best agency to develop laser ignition. After its feasibility is shown, an engine manufacturer, working with an ignition system supplier, is best equipped to carry the development through from product research to a commercial product.

<u>III. Feasibility of the option</u>

A. Technical: The primary technical risks are whether sufficiently high light flux can be carried through the fiber optic and whether the fiber optic is sufficiently durable. Laser ignition can be retrofitted to engines that use 18-mm spark plugs.
B. Environmental: If the technical barriers can be overcome, there is little environmental risk to laser ignition.
C. Economic: If the technical barriers can be overcome, the economic incentive for its adoption will depend on whether the engine must operate continuously or whether downtime can be scheduled to change spark plugs. The requirement for continuous operation favors laser ignition, which is expected to have a higher initial cost than spark ignition, but which can eliminate most of the

downtime for changing spark plugs.

IV. Background data and assumptions used TBD.

V. Any uncertainty associated with the option (Low, Medium, High) Medium to High

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups) TBD

2. Air-Separation Membranes

I. Description of the mitigation option

Overview

The purpose of air-separation membranes is to change the proportion of nitrogen to oxygen in air. A membrane can be optimized to either enrich the oxygen content or to enrich the nitrogen content. Both the oxygen enrichment mode and the nitrogen enrichment mode have been tested in the laboratory with diesel engines. The nitrogen enrichment mode has been tested in the laboratory with Natural Gas Fuel as well. The oxygen enrichment mode and the nitrogen enrichment mode are mutually exclusive.

Oxygen enrichment produces a dramatic reduction in particulate emissions at the expense of increased NOx emissions. However, Poola [***ref Poola paper***] has shown that the effects are non linear such that a small enrichment (1 percentage point or less) produces a significant reduction in particulate emissions with only a small increase in NOx emissions. By retarding the injection timing, one can achieve a reduction in both NOx and particulate emissions. The overall benefits of oxygen enrichment are relatively small, so it will not be considered further.
Nitrogen enrichment produces the same effect on emissions as exhaust-gas recirculation; NOx decreases while particulate emissions increase. Unlike diesel exhaust, the nitrogen enriched air does not contain particulate matter. Manufacturers of heavy-duty diesel engines are concerned that introducing particulate matter from EGR into the engine may cause excessive wear of the piston rings and cylinder liner. Thus, nitrogen enriched air is seen as an alternative to EGR. The published data in natural-gas engines show engine-out NOx reductions of 70% are possible with nitrogen-enriched combustion air. [Biruduganti, et al.]

Air Quality and Environmental Benefits

Oxygen-enriched air has only been demonstrated in the laboratory to be beneficial with one type of engine that is considered obsolete. Although the results are encouraging, further testing with a more modern engine would be necessary to confirm the decrease in both NOx and particulate emissions.

The development of oxygen-depleted air is further along and has been demonstrated as an effective alternative to EGR.

Economic

Use of oxygen-depletion membranes might have a higher initial cost than EGR, but would facilitate a longer interval between overhauls. It will have no adverse impact on engine wear or durability; however, EGR at high levels will have reduced engine durability.

Trade-offs

Engine manufacturers are concerned about the abrasive effects of particulate matter on piston rings and cylinder liners and other deleterious effects of EGR [830.pdf]. For the manufacturer the tradeoff is between the initial cost of an oxygen depletion membrane versus the higher frequency of overhauls required with EGR.

<u>II. Description of how to implement</u>

A. Mandatory or voluntary: Implementation should be voluntary because the primary incentive for implementation is economic.
B. Indicate the most appropriate agency(ies) to implement: The engine manufacturer is the appropriate agency to implement air separation membranes because the primary issue is initial cost versus frequency of overhauls.

<u>III. Feasibility of the option</u>

A. Technical: The technical feasibility of oxygen-depletion membranes has been demonstrated as an alternative to EGR. The technical feasibility of oxygen-enrichment membranes has only been shown in the laboratory for one type of engine. The technical advantages of nitrogen enrichment with membranes have been demonstrated in the laboratory for natural gas and diesel engines.

B. Environmental: The environmental benefits of oxygen-depletion membranes are the same as EGR.

C. Economic: Membrane manufacturers are presently unable to produce enough membranes for widespread implementation of the technology in truck engines. However, the oil and gas industry is a smaller market, which might allow the membrane manufacturers to ramp up their production levels. Because of this situation, the economic feasibility of air-separation membranes is difficult to assess.

<u>IV. Background data and assumptions used</u>

www.enginemanufacturers.org/admin/library/upload/830.pdf

Published technical papers by Argonne National Laboratory and others.

<u>V. Any uncertainty associated with the option (Low, Medium, High)</u>

Low to medium. The technology would receive a "low" uncertainty rating if the availability issue were more settled.

<u>VI. Level of agreement within the work group for this mitigation option TBD</u>

<u>VII. Cross-over issues to the other source groups</u> (please describe the issue and which groups) TBD

3. Rich-Burn Engine with Three-Way Catalyst

<u>I. Description of the mitigation option</u>

Overview

Rich-burn engines with a three-way catalyst borrow from the well developed automobile technology using the same type of catalyst. Key to efficient operation of the catalyst is maintenance of slightly lean of stoichiometric operation of the engine. Typically the exhaust oxygen content is maintained in a narrow range not exceeding 0.5% by means of an oxygen sensor in the exhaust stream and closed-loop feedback control of the fuel flow. The oxygen content is enough to catalytically oxidize carbon monoxide and unburned hydrocarbons as it chemically reduces NOx to molecular nitrogen and water. If the engine is operated lean of its desired operating point, NOx reduction efficiency drops off dramatically. If operation is rich, emissions of carbon monoxide and unburned hydrocarbons increase.

It is commercially available as a retrofit for smaller engines. Larger engines are usually operated in the lean-burn mode.

Air Quality and Environmental Benefits
Air quality benefits would be similar to automobiles, where catalytic converters are universally used with rich burn engines.

Economic
Cost of three-way catalyst systems is considered high, but less than that of SCR with a lean-burn engine.

Trade-offs
For small engines (that is, less than 200 BHP) lean burn technology may not be available. Where there is a choice of rich-burn or lean-burn engines, the lean-burn engines offer better fuel economy and more effective, albeit more expensive, overall emissions control via SCR and oxidation catalysts.

II. Description of how to implement

A. Mandatory or voluntary: The use of three-way catalysts will be dictated by the stringency of emissions regulations. Three-way catalysts are sufficiently expensive that they are not likely to be adopted voluntarily.
B. Indicate the most appropriate agency(ies) to implement: U.S. EPA and state agencies

III. Feasibility of the option

A. Technical: The technology is commercially available and has been proven effective. Rich-burn engines have higher engine-out NOx emissions, typically about 10-20 g/BHP-hr [830.pdf and reportoct31.doc], than lean-burn engine have. This requires the removal of at least 95% of the NOx if overall emissions are to be reliably reduced to less than 1 g/BHP-hr.
B. Environmental: The State of Colorado estimates that a 3-way catalyst can remove 75% of the NOx, unburned hydrocarbons, and carbon monoxide [reportoct31.doc, although manufacturers of equipment claim that 98-99% of these pollutants are removed.
C. Economic: The State of Colorado estimates that the cost of retrofitting a three-way catalyst system to a rich-burn engine over 250 BHP is $35,000 with annual operating costs of $6,000 [reportoct31.doc].

IV. Background data and assumptions used

http://apcd.state.co.us/documents/eac/cd2/reportoct31.doc

www.enginemanufacturers.org/admin/library/upload/830.pdf

V. Any uncertainty associated with the option (Low, Medium, High) Low

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups TBD

4. Lean-Burn NOx Catalyst, Including NOx Trap

<u>I. Description of the mitigation option</u>

Overview

Lean-burn NOx catalysts have been under development for at least two decades in the laboratory with the intent of producing a lower cost alternative to SCR.

Several variants of lean-burn NOx catalysts have been studied: (1) Passive lean-burn NOx catalysts simply pass the exhaust over a catalyst. The difficulty has been low NOx conversion efficiency because the oxygen content of a lean-burn exhaust works against chemical reduction of NOx. Conversion efficiencies of the order of 10% are typical [park.doc.

(2) Active lean-burn NOx catalysts use a fuel as a reductant. The catalyst decomposes the fuel, and the resulting fuel fragments either react with the NOx or oxidize. Methane is much more difficult to decompose than heavier fuels, such as diesel [aardahl.pdf. A wide range of NOx reduction efficiencies from 40% to more than 80% have been published [park.doc and icengine.pdf]. Variants of active lean-burn catalyst systems may use plasma or a fuel reformer to produce a more effective reductant than neat fuel [aardahl.pdf, 2003_deer_aardahl.pdf, and 80905199.htm].

(3) NOx trap catalysts are a more recent development that has seen some laboratory success. Operation is a two-step cyclic process. In the first stage the NOx trap adsorbs NOx while the engine operates in a lean-burn mode. In the second stage, the engine operates with excess fuel in the exhaust. The fuel decomposes on the catalyst and reduces the NOx to molecular nitrogen and water. When the supply of trapped NOx is exhausted, the system reverts back to first-stage operation. NOx reduction efficiencies in excess of 90% have been published [parks01.pdf. A sophisticated engine control is required to make this system work.

Air Quality and Environmental Benefits

NOx traps have been proven to be effective and have seen some limited commercial success in Europe. NOx traps are one of the reasons for the dramatic reduction in sulfur content of diesel fuel in the U.S. Fuel-borne sulfur causes permanent poisoning of NOx-trap catalysts. There are doubts regarding the NOx conversion efficiency levels after 1,000 hours or longer use. This should be evaluated, as well as the durability of the equipment.

Active lean-NOx catalysts have seen limited commercial success because they are less effective than NOx traps and are not being considered for on-road diesel engines. Some instances of formation of nitrous oxide (N2O) rather than complete reduction of NOx have been reported.

Passive Lean-NOx catalysts do not provide enough NOx reduction to be considered viable.

Economic

Costs of retrofitting a lean-burn NOx catalyst are estimated at $6,500 to $10,000 per engine [retropotentialtech.htm], $15,000-$20,000 including a diesel particulate filter [V2-S4_Final_11-18-05.pdf] for off-road trucks. Estimates are $10-$20/BHP for stationary engines [icengine.pdf].

Little information on the cost of NOx-trap catalytic systems was found. The overall complexity of a NOx-trap system is only slightly more than that of a lean-burn NOx catalyst, so costs can be expected to be slightly higher. With methane-burning engines, both active lean-burn NOx catalysts and NOx-trap catalysts require a fuel reformer or other means of dissociating methane. This will add an increment of cost.

Both active lean-NOx technology and NOx-trap technology impose a fuel penalty of 3-7%.

Trade-offs

NOx-trap systems compete with SCR systems. For methane-burning engines, a fuel reformer is required for NOx-trap systems. Fuel reformers are less well developed.

If emissions regulations can tolerate higher NOx emissions, an active lean-burn NOx catalyst might be considered.

I. Description of how to implement

A. Mandatory or voluntary: The costs of lean-burn NOx catalysts and NOx traps are such than voluntary compliance is unlikely. However, depending on the strictness of the regulations, the user may have a choice of systems.
B. Indicate the most appropriate agency(ies) to implement: U.S. EPA and state agencies.

II. Feasibility of the option

A. Technical: NOx-trap systems are proven and commercially available for diesel engines. However, they require low-sulfur diesel fuel (less than 15 ppm) to minimize sulfur poisoning of the catalyst. Active lean-burn catalysts are available, but they have a lower NOx reduction efficiency than NOx-trap systems have. Both the lean-burn NOx catalyst and the NOx trap requires a fuel reformer (which can be a catalyst stage upstream of the NOx catalyst) to operate at full efficiency with natural-gas fueled engine.
B. Environmental: Lean-burn NOx catalysts and NOx-trap catalysts do not have the ammonia slip issue that SCR systems have, but lean-burn NOx catalysts may only partially reduce some of the NOx to nitrous oxide (N2O). The NOx reduction efficiency of NOx traps is similar to that of SCR systems (>90%), but active lean-burn NOx catalysts have a lower efficiency (40-80%).
C. Economic: Lean-burn NOx catalysts and NOx traps have lower costs than SCR and they avoid the need to purchase and maintain a separate reductant. However, both lean-burn NOx catalysts and NOx traps impose a fuel consumption penalty of 3-7%.

III. Background data and assumptions used

Abstract of Caterpillar paper found at www.emsl.pnl.gov/new/emsl2002/abstracts/park.doc.

www.meca.org.galleries/default-file/icengine.pdf

www.energetics.com/meetings/recip05/pdfs/presentations/aardahl.pdf

www.eere.energy.gov/vehiclesandfuels/pdfs/deer_2003/session10/2003_deer_aardahl.pdf

www.swri.org/epubs/IRD1999/08905199.htm

www.feerc.ornl.gov/publications/parks01.shtml

www.epa.gov/oms/retrofit/retropotentialtech.htm

www.wrapair.org/forums/msf/projects/offroad_diesel_retrofit/V2-S4_Final_11-18-05.pdf

IV. Background data and assumptions used None

V. Any uncertainty associated with the option (Low, Medium, High)

NOx traps have a low uncertainty if they are used with low sulfur diesel fuel. They have a medium uncertainty when used with natural gas because of the need to reform the fuel.

Lean-burn NOx catalysts have a medium uncertainty because they may not be able to meet future emissions regulations.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups

To be determined. The issue of incomplete NOx reduction that leaves some nitrous oxide (N_2O) may be moot if active lean-burn NOx catalysts cannot meet future emissions regulations.

5. Homogeneous-Charge Compression-Ignition (HCCI) Engine

I. Description of the mitigation option

Overview

Homogeneous charge compression ignition (HCCI) engines are under development at several laboratories. In these engines a fully mixed charge of air and fuel is compressed until the heat of compression ignites it. The HCCI combustion process is unique since it proceeds uniformly throughout the entire cylinder rather than having a discreet high-temperature flame front as is the case with spark ignition or diesel engines. The low-temperature combustion of HCCI produces extremely low levels of NOx. The challenge of HCCI is in achieving the correct ignition timing, although progress is being made in the laboratories.[1]

Only a few experimental measurements of NOx from (HCCI) engines have been reported. The measurements are typically reported as a raw NOx meter measurement in parts per million rather than being converted to grams per horsepower-hour. Dibble reported a baseline measurement of 5 ppm when operated on natural gas.[2] Green reported NOx emissions from HCCI-like (not true HCCI) combustion of 0.25 g/hp-hr.[3] The achievable NOx emission levels are yet to be determined. It is not currently known if HCCI technology can be applied to all engine types and sizes. However, if all reciprocating engines could be converted to HCCI so that the engines produce no more than 0.25 g/hp-hr, then the overall NOx emissions reduction would be 80% in both Colorado and New Mexico using the calculation methodology of the SCR mitigation option.

II. Description of how to implement

A. Mandatory or voluntary: It is too early to determine whether implementation of this technology will be voluntary or mandatory.
B. Indicate the most appropriate agencies to implement

III. Feasibility of the option

A. Technical: HCCI is in the laboratory stage of development.

B. Environmental: HCCI has the potential of extremely low NOx levels.

C. Economic: HCCI is not sufficiently developed to have proven economic feasibility.

IV. Background data and assumptions used

1. Bengt Johansson, "Homogeneous-Charge Compression-Ignition: The Future of IC Engines," Lund Institute of Technology at Lund University, undated manuscript.

2. Robert Dibble, et al, "Landfill Gas Fueled HCCI Demonstration System," CA CEC Grant No: PIR-02-003, Markel Engineering Inc.

3. Johney Green, Jr., "Novel Combustion Regimes for Higher Efficiency and Lower Emissions," Oak Ridge National Laboratory, "Brown Bag" Luncheon Series, December 16, 2002.

V. Any uncertainty associated with the option (Low, Medium, or High)

HCCI has high uncertainty.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups (Please describe the issue and which group.)

Summary

Five technologies are reported: laser ignition, air-separation membranes, rich-burn engine with three-way catalyst, lean-burn NOx catalyst, and Homogeneous-Charge Compression-Ignition (HCCI) Engine.

Laser ignition is not presently a commercial product. The impetus for investigating it is the potential to eliminate the need for changing spark plugs. It will also allow operation at leaner air-fuel ratios, higher compression ratios, and higher turbocharging pressure. Leaner air-fuel ratios imply lower engine-out NOx emissions so the after treatment can be smaller or can give lower overall emissions. Higher compression ratios and turbocharging ratios imply higher engine efficiency.

Air-separation membranes used to deplete oxygen from the combustion air can serve as a clean replacement for EGR. That is, an engine using oxygen-depleted air would not be ingesting combustion products. Engine manufacturers are concerned that EGR will shorten the life of their engines and lead to premature overhauls and warranty repairs. The technology has been demonstrated in the laboratory, but has not been used for heavy-duty trucks because membrane manufacturers do not have enough production capacity for the market. Stationary engines are a smaller market, so the membrane manufacturers may be able to ramp up their capacity with stationary engines. Applicability is to diesel engines and rich-burn natural-gas engines. Oxygen-depletion membranes have not been tested with lean-burn natural-gas engines.

A rich-burn engine with a three-way catalyst is a mature technology that is borrowed from automobile engines. The three-way catalyst effectively control NOx, unburned hydrocarbon, and carbon monoxide emissions. It requires an exhaust oxygen sensor with a closed-loop control of the fuel so that exhaust oxygen is maintained in a narrow range not exceeding 0.5%. It can be retrofitted to existing engines and is primarily applicable to small engines for which lean-burn combustion is not available. Its primary disadvantages are cost and the inherently lower efficiency of rich-burn engines compared to lean-burn engines.

Lean-burn NOx catalysts have several forms, but the one that is of most interest is the NOx-trap catalyst. Unlike SCR, lean-burn NOx catalysts use the engine's fuel as a reductant and do not require a separate supply of reductant. It is a well proven in the laboratory and is commercially available in Europe for diesel engines, but it requires a fuel reformer if natural gas is used as the reductant. A sophisticated control system is required to cycle the engine between its two modes of operation. Ammonia slippage is not an issue with NOx traps, and if there is any slippage of unburned fuel it can be removed with an oxidation catalyst. Cost is high but less than that of SCR systems. A disadvantage of NOx traps is that they are intolerant of fuel-borne sulfur. For diesel fuel, the sulfur content must be less than 15 ppm. Fuel-borne sulfur permanently poisons the catalyst. Since fuel is used as a reductant, there is a fuel consumption penalty of 3-7%.

ENGINES: MOBILE/NON-ROAD

Mitigation Option: Fugitive Dust Control Plans for Dirt/Gravel Road and Land Clearing

I. Description of the mitigation option

Fugitive dust emissions from traffic on dirt roads and construction sites are a nuisance and cause frequent complaints. Health concerns related to PM 10 (particulate matter less than 10 microns in size) exposure to high concentrations are breathing, aggravated existing respiratory and cardiovascular disease, lung damage, asthma, chronic bronchitis, and other health problems. Adequate measures could include wind breaks and barriers, water or chemical applications, control of vehicle access, vehicle speed restrictions, gravel or surfacing material use, and work stoppage when winds exceed 20 miles per hour. Activities occurring near sensitive and/or populated areas should receive a higher level of preventive planning. Sensitive receptors would include schools, housing, and business areas.

Economic burdens include increase business costs associated with increased road maintenance, loss of time and productivity associated with work stoppage during high wind days, and increased travel times due to speed restrictions. However, reduced wear on roads and vehicles may be recognized through vehicle speed restrictions.

II. Description of how to implement

A. Mandatory or voluntary: Speed restrictions, regular road maintenance, and construction activity restrictions during high wind days would be mandatory. Road surfacing, wind breaks and barriers and vehicle access control would be voluntary.

B. Indicate the most appropriate agency (ies) to implement: The states, tribal governments, BLM, FS, County, and Industry.

III. Feasibility of the option

A. Technical: The current BLM Road committee is a functional working group with 13 road maintenance units. An industry representative is assigned to each unit to oversee road construction and maintenance activities through a cost-sharing program. BLM law enforcement along with county and state law enforcement could enforce speed restrictions. Industry could make observing speed limits a company policy. Conditions of approval could be added to permitted activities to restrict surface disturbing activities during high wind days. However, industry would prefer the use of other mitigation measures such as road surface treatments (e.g. fresh water or special emulsion) during high wind days.

B. Environmental: The environmental benefits from regular and proper road maintenance, speed restrictions, and surface disturbing activities during high wind days are well documented.

C. Economic: Cost sharing is an important purpose of the current roads committee that is very active and functional work group with regularly scheduled meetings. Funding for speed enforcement is an intricate part and regularly funded operation of BLM, county and state law enforcement.

IV. Background data and assumptions used

1. BLM Gold Book-Surface Operating Standards for Oil and Gas Exploration and Development.
2. Numerous studies on road related erosion issues and standards exist.
3. Studies on excessive road speed and dust development.

V. Any uncertainty associated with the option (Low, Medium, High) Low

VI. Level of agreement within the work group for this mitigation option
Four member drafting team support this option

VII. Cross-over issues to the other source groups None at this time.

Mitigation Option: Use Produced Water for Dust Reduction

I. Description of the mitigation option

This option involves using produced water on roads for dust suppression. Large volumes of water are often produced in conjunction with natural gas production, especially coal bed methane (CBM) production. Wells often produce up to 100-400 barrels/day. CBM produced water quality ranges from nearly fresh water to well above 10,000 ppm total dissolved solids (TDS) and is readily available as an option for road dust suppression. The produced water used for dust mitigation would have to have low TDS and low sodium levels that meet BLM and county standards. Some CBM water meets these standards but not all of it.

Economic benefits could be realized by oil and gas operators in reduced trucking and disposal costs. Likewise, there are associated environmental benefits to this reduced trucking as is outlined in another mitigation strategy. However, the use would be as needed and seasonal (during prolonged dry periods or drought).

Environmental concerns and issues would arise concerning 1) salt build up along roadways, 2) migration of water and associated pollutants off the roadway, 3) impacts to vegetations, 4) salt loading to river systems.

Differing Opinion: Produced water in the Four Corners region contains toxins and therefore should not be used for dust mitigation. The potential environmental concerns include more than just salt-related impacts. Produced waters are of variable quality. Depending on the source, the water may contain high concentrations of constituents other than salts. Data on produced water quality is not widely available to the public. One example of produced water quality, however, was published in a recent report prepared with support from the U.S. Department of Energy. The data show that in the New Mexico portion of the San Juan Basin, there can be elevated concentrations of various metals and other constituents in produced water (in addition to elevated salts – those data not shown).[1]

	McGrath SWD[2]		**Four CBM injection wells**[3]	
All values in mg/L	**Max**	**Min**	**Max**	**Min**
Barium	8.0	0.72	23.9	1.86
Boron	3.0	1.0	2.87	1.6
Bromium	21.8	7.1	15.2	2.4
Copper	0.019	ND		
Chromium	0.035	ND	0.005	
Iron (dissolved)[4]	187	1.1	0.843	0
Selenium	0.080	ND	0.0171	ND

[1] DiFilippo, Michael N. August, 2004. Use of Produced Water in Recirculating Cooling Systems at Power Generating Facilities. Semi-Annual Technical Progress Report October 1, 2003 to March 31, 2004. Report produced with support from U.S. Department of Energy, Award No. DE-FC26-03NT41906. pp. 12-3.
[2] McGrath Saltwater Disposal Well (SWD): data were from a 30 day random sampling of the SWD well), which was operated by Burlington (now, presumably Conoco).
[3] CBM SWD wells operated by Dugan (Salty Dog 2 and 3 Injection Wells) and Richardson (Turk's Toast and Locke Taber Injection Wells).
[4] According to DiFilippo (page 10), most of the iron comes from aboveground carbon steel pipe used to convey produced water. So, presumably, if water were applied from trucks getting water from the well site, itself, this would not be a concern. If it were water being loaded at the SWD facility, then the iron would be present.

Silver			0.20	ND
Strontium	55	7.2	34.5	1.73
Lead	0.031	ND	0.1	
Total Petroleum Hydrocarbons (TPH)	520	23	17	ND
Zinc			0.298	ND

* ND is non-detected

Produced water may also contain chemical additives put downhole during the drilling, stimulation or workover of the wells. Some of these treatment chemicals, such as biocides, can be lethal to aquatic life at levels as low as 0.1 part per million.[5] It is very difficult to obtain information on the concentrations of treatment chemicals and additives in produced water.

Environmental Justice Issues: Only with the permission of surface owners, municipalities, counties, etc. should produced water be applied to roads. And these entities should be provided with produced water quality information prior to road spreading.

Wyoming requires landowner consent prior to road spreading, which is an important provision to ensure that surface owners have a say in the application of large quantities of water that could affect their property. In Pennsylvania, other jurisdictions, such as municipalities, also have a say with respect to whether or not road spreading is allowed.[6]

II. Description of how to implement

A. Mandatory or voluntary: The use of produced water would be voluntary; however, ultimate approval to do so would be up to the state authority that has primacy over the disposal and use of produced water.
B. Indicate the most appropriate agency(ies) to implement: OCD, BLM, FS.

It may also be necessary to include the states in the implementation of any permitting process related to road spreading since these agencies have the expertise and develop the environmental standards related to surface and groundwater pollution. There is a precedent for involving environment departments. In Wyoming, although the Oil Conservation Commission is responsible for permitting road spreading applications, the operations must also be approved by their Department of Environmental Quality.[7]

III. Feasibility of option

A. Technical: This option is technically feasible, but would require strict controls and monitoring. "Because of the potential for contaminants from the brine to leach into surface or ground waters, the Department of Environmental Protection (DEP) has developed guidelines that must be followed when spreading brine on unpaved roads."[8] It would be advisable for the responsible agencies to develop their

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[5] Argonne National Laboratory. January, 2004. A White Paper Describing Produced Water from Production of Crude Oil, Natural Gas and Coalbed Methane. Prepared for U.S. Department of Energy. Contract No. W-31-109-Eng-38.
[6] http://www.dep.state.pa.us/dep/deputate/minres/oilgas/fs1801.htm
[7] Rules and Regulations of the Wyoming Oil and Gas Conservation Commission
Chapter 4, Section 1 http://www.cbmcc.vcn.com/dust.htm
"(nn) Landfarming and landspreading must be approved by the DEQ. Jurisdiction over roadspreading or road application is shared by DEQ and the Commission. . ."
[8] http://www.dep.state.pa.us/dep/deputate/minres/oilgas/fs1801.htm

own guidelines or policies to ensure that road spreading practices are carried out in an environmentally sound manner.

B. Environmental: Would require constraints on the allowable TDS and/or SAR content of the water and volumes applied. Baseline field testing for migration/movement would be required to determine if salt build-up is occurring. The use of boom type sprayer (i.e. spreader bars) to prevent pooling and washing off of roadway needs to be highly considered. A responsible party on site during application would be necessary and signage indicating road maintenance being conducted.

Most jurisdictions that allow road spreading do not require chemical data on anything but the salts or dissolved solids (TDS). While TDS includes constituents such as dissolved metals, it does not provide any specific information as to the concentrations of the various metals. Basing the acceptability of using produced water for road spreading on salt content or TDS overlooks the potential impacts from other produced water constituents like metals, hydrocarbons, treatment chemicals and radionuclides (e.g., strontium).

Prior to application of produced water for road spreading purposes, it would be prudent to analyze the water for all potentially harmful constituents. In 2000, there was a case in Garfield County, CO, where a company illegally spread flowback fluids from a workover operation. Samples of the produced water subsequently showed that TDS levels and BTEX were above state drinking water standards.[9]

Prohibit spreading of flowback water. In Pennsylvania, operators are not allowed to spread produced water that main contain treatment chemicals. “Only production or treated brines may be used. The use of drilling, fracing, or plugging fluids or production brines mixed with well servicing or treatment fluids, except surfactants, is prohibited. Free oil must be separated from the brine before spreading.” Essentially, this would mean that the operator would have to wait a certain period of time to allow the majority of the treatment chemicals to flow out of the well before using the produced water for road spreading purposes.

C. Economic: Some operators may see a reduction in hauling and trucking cost associated using produced water for dust control.

IV. Background data and assumptions used

1. Currently produced water is used in some areas for road reconstruction and maintenance, but not for dust reduction. Current levels allowed are 5,000 TDS for maintenance and 18,000 TDS for reconstruction.
2. Could consider higher TDS levels of use with tight restriction on applications methods and timing.
3. Assume applications would be seasonal (during summer dry months)
4. Restricted to main collector road or on all roads with high traffic flow.
5. Need to protect operator’s investment for roadwork already completed.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium uncertainty to environment (water quality and vegetation).

VI. Level of agreement within the work group for this mitigation option.

All members of drafting team support this option.

VII. Cross-over issues to other source groups None at this time.

[9] Colorado Oil and Gas Information System. 7/6/2000. Notice of Alleged Violation Report. Barrett Resourced Corp. Document No. 850224. http://oil-gas.state.co.us/cogis/NOAVReport.asp?doc_num=850224

Mitigation Option: Pave Roads to Mitigate Dust

I. Description of the mitigation option

This option involves paving roads that service the vast amounts of oil and gas locations in the four corners region. The benefits to air quality would be a significant reduction in dust generated by traffic in the San Juan Basin. Consideration should be given to paving only those collector roads that are located near populated areas and those that received heavy traffic and excessive dust because of high cost of paving. Currently a pilot project is being proposed to use hot emulsified asphalt on reconstructed collector roads. The hot asphalt would be incorporating it into the sandstone caps material using a road re-claimer or blade in an effort to create a durable driving surface.

Economic burdens would be extreme costs to oil and gas operators, federal, state and local governments associated with paving and maintaining a vast network of roads in the San Juan Basin. There would be an immediate increase in traffic accidents associated with an eminent increase in speed associated with paved roads.

II. Description of how to implement

A. Mandatory or voluntary: The construction and road base preparation necessary to properly pave a road would be voluntary

B. Indicate the most appropriate agency(ies) to implement: Industry, OCD, BLM, FS, County, State.

III. Feasibility of option

A. Technical: This option is technically feasible but not practical to pave all roads. Consideration needs to be given to highly travel collector roads and road near heavily populated areas. Portions of heavily travel roads could be considered for paving.

B. Environmental: Would reduce long term dust emissions from vehicle traffic throughout the San Juan Basin but there would be some shorter term increases in emissions associated with asphalt production, paving, and the construction equipment paving the road itself. However, increase accidents and speeding could be drawbacks. Additional law enforcement would be required or re-prioritized workload to curtail speeding.

C. Economic: The cost to prepare, pave, and maintain roads throughout the San Juan Basin are not practical on all roads. Furthermore, the cost to reclaim "paved roads" as part of the restoration process upon well abandonment would be substantial. Consideration could be give to paving only portions of main collector roads, especially in populated areas with heavy traffic.

IV. Background data and assumptions used

1. Pilot project currently proposed. Need to evaluate the effectiveness of using hot emulsified asphalt. Not practical to pave all roads in the San Juan Basin.
2. Restricted to main collector road with heavy traffic, dust problems, and populated areas.
3. Would require addition capital outlay and cost sharing.

V. Any uncertainty associated with the option (Low, Medium, High)

High, due to cost and feasibility.

VI. Level of agreement within the work group for this mitigation option.

Members agree that this option has some merit but in limited areas. Not practical to consider the entire San Juan Basin.

VII. Cross-over issues to other source groups None at this time.

Mitigation Option: Automation of Wells to Reduce Truck Traffic

I. Description of the mitigation option

This mitigation option would involve equipping wells with a variety of technology for the ultimate purpose of being able to decrease traffic to well sites when everything is operating normally. The potential air quality benefits include reduced dust and tailpipe emissions from vehicle traffic. Other potential environmental benefits include reduced vehicular fuel consumption (and therefore the need for crude oil feedstocks). Economically, the energy companies could benefit by reducing their workforces and the expenses paid for contractors. As this automation may require the electrification of the equipment, the air quality benefits may be offset by emissions elsewhere and of a different nature. Costs for implementing this option may entail the installation of massive electrification systems to power the sensors, radios, and automated valves (vista issues). Additionally, should every well not be checked on a daily basis, there is believed to be a high likelihood that leaks small enough to be undetectable by the automation sensors could go on unabated until the next time the well was visited. This would represent a real tradeoff of risk (air quality vs. soil / water impact). Significant burden would fall on the operator in such a situation. An additional benefit of this option is that once electricity is available at the site, it would increase the feasibility of the electric compressor option included under Stationary RICE.

II. Description of how to implement

The oil & gas industry already uses automation technology where technically and economically feasible. Therefore, this mitigation option would best be implemented in a voluntary manner. As such, agency involvement would not be required.

III. Feasibility of the option

A. Technical: The technology exists today to implement this mitigation option.
B. Environmental: A study would need to be made to determine the relative benefit of reducing emissions at the well site but increasing emissions during electrification and offsite power generation. (Cumulative Effects Work Group task?)
C. Economic: In some cases the implementation of this technology is economically feasible. In many others it is not. Forced implementation could very well hasten the uneconomic status of a well resulting in the premature abandonment of the well and its hydrocarbon products.

IV. Background data and assumptions used

While EPA does have AP-42 emission factor data available for unpaved roads (13.2.2), no input information was available in the time frame desired to make any calculations / determinations, hence the high-level and qualitative analysis. (Cumulative Effects Work Group task?)

V. Any uncertainty associated with the option

High. The feasibility of implementing this option is very situation specific. It is believed that widespread implementation (75% of wells) is probably not feasible.

VI. Level of agreement within the work group for this mitigation option

Subgroup is in agreement with this option.

Cross-over issues to the other source groups

None at this time.

Mitigation Option: Reduced Vehicular Dust Production by Enforcing Speed Limits

I. Description of the mitigation option

This mitigation option would involve enforcing speed limits on unpaved roads in an attempt to reduce dust emissions. The potential air quality benefits include reduced dust emissions from slowed vehicle traffic. Another potential environmental benefit (albeit marginal) is reduced vehicular fuel consumption (and therefore the need for crude oil feedstocks). Economically, although theoretically less work would be accomplished in the same time period, this impact would be insignificant since the degree of excess over the speed limit is probably not such that implementation of this mitigation strategy would make a significant difference.

A. Public Roads: Enforcement on public roads would be most easily accomplished using local law enforcement agencies. Costs for stepping up enforcement of the speed limits on public roads might include additional funds for increased staff for the local law enforcement agencies.

B. Private Roads: To the extent the unpaved roads are private, the setting and enforcing of speed limits would have to take place in a cooperative agreement between local landowners and energy companies. Since energy companies are not staffed, trained or equipped to be law enforcement agents, this would represent a significant cost shift to the energy companies. Costs for implementing this option on private roads would entail legal review to understand on what basis such" private law enforcement" could take place, the negotiating of agreements with landowners, the posting of signs, and the staffing, training, and equipping of workers to fulfill this function.

C. Assistance: Cumulative Effects work group would be needed to understand the relative benefit of reduced speed on dust production.

II. Description of how to implement

A. On public unpaved roads, enforcement of existing speed limits could be seen as mandatory. The most appropriate agencies to implement are the existing local law enforcement agencies.

B. On private roads, implementation would have to be voluntary as no agency can force a landowner to undertake such a proposition. It is not appropriate for any agencies to get involved in the implementation of this mitigation option. It would be most appropriate for the environmental agencies to simply recognize this as a bona fide emission reduction strategy, and then let the energy company determine where and when to implement such a strategy.

III. Feasibility of the option

A. Technical – Greater enforcement of speed limits on public unpaved roads would be feasible. Establishing and enforcing speed limits on private unpaved roads is feasible but less so.

B. Environmental - Assistance from the Cumulative Effects work group would be needed to understand the relative benefit of reduced speed on dust production (how much reduction in speed is needed to have a significant reduction of dust?).

C. Economic - Assistance from the Cumulative Effects work group would be needed to understand the relative economic benefit of reduced speed on dust production.

D. Public Perception – This could be an issue based on the assumption that most people would want any additional funding for police activities to go toward safety/crime issues.

IV. Background data and assumptions used

While EPA does have AP-42 emission factor data available for unpaved roads (13.2.2), no input information was available in the time frame desired to make any calculations / determinations. Hence the high-level and qualitative analysis in this option paper. The governing equations do however include speed as a component.

V. Any uncertainty associated with the option

High. Assistance from the Cumulative Effects work group would be needed to understand the relative economic benefit of reduced speed on dust production. Once that is understood, an analysis could be made to reduce the economic and regulatory uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups

It is believed that this issue will cross-over to the Other Sources group.
Could the issue described in IV above be addressed by the Cumulative Effects work group?

Mitigation Option: Reduced Truck Traffic by Centralizing Produced Water Storage Facilities

I. Description of the mitigation option

This mitigation option would involve reducing vehicular traffic on unpaved roads (and hence dust production) by centralizing produced water storage facilities and pumping water to them. Much of the large truck traffic on unpaved lease roads is water haulers. Therefore, one strategy to reduce dust is to reduce water hauler traffic. However, unless the produced water could be piped directly to the disposal (injection well) location, the same volume of truck traffic would exist. Therefore, to reap the benefits from this strategy, it would be necessary to either pipe the water directly to the disposal location, or to site the centralized produced water storage facility along a paved road such that the water transporters would not be driving on unpaved roads and creating dust.

Benefits from this strategy include dust reduction, vehicle tailpipe exhaust emission reduction (potential), reduced road maintenance, and marginally safer roads. Burdens would fall exclusively on the energy companies. These burdens would include obtaining rights-of-way to lay the needed pipelines, securing the pipe, securing trenching and installation services, and paying crews to make the necessary tie-ins. As much of the produced water in southern Colorado is essentially fresh in nature, heat tracing may be needed to prevent the freezing and bursting of pipes.

Tradeoffs would include the pollutants emitted at the source of the power used to drive the transfer pumps. This power production could be either at the well location (natural gas fired) or at the power plant (electric). Additionally, the dust emissions are currently dispersed over a large area. Centralizing storage would greatly increase tailpipe emissions locally and potentially produce local air quality, noise, and traffic safety issues. Additionally, aggregating produced water in one location increases the potential for a catastrophic release. This would represent a real tradeoff of risk (air quality vs. soil / water impact). Additional tradeoffs include the emissions produced at the point of pipe manufacture and the emissions from the trenching operations. Assistance is needed from the Cumulative Effects work group to estimate the net air quality gain from centralizing produced water storage facilities.

II. Description of how to implement

A. This mitigation option should be implemented on a voluntary basis. Forced implementation could hasten the uneconomic status of groups of wells resulting in premature abandonment of the wells and their hydrocarbon products.
B. The most appropriate agency to implement would be the environmental agency through permitting incentives/offsets. It would be necessary to first understand the relative benefit of reducing emissions from lease road traffic but increasing emissions elsewhere (Cumulative Effects Work Group task).

III. Feasibility of the option

A. Technical: The technology exists today to implement this mitigation option.
B. Environmental: A study would need to be made to determine the relative benefit of reducing emissions from lease road traffic but increasing emissions elsewhere (Cumulative Effects Work Group task).
C. Economic: In some cases the implementation of this technology will be economically feasible. In many others it will not be.

IV. Background data and assumptions used:

While EPA does have AP-42 emission factor data available for unpaved roads (13.2.2), no input information was available in the time frame desired to make any calculations / determinations. Hence the high-level and qualitative analysis. This could be a Cumulative Effects Work Group task.

V. Any uncertainty associated with the option (Low, Medium, High):
High. Assistance from the Cumulative Effects work group would be needed to understand the relative economic benefit of reduced truck traffic vs. laying miles of pipelines and setting many pumps. Once that is understood, an analysis could be made to reduce the economic and regulatory uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option

V. Cross-over issues to the other source groups
It is believed that this issue will not cross-over to any other source work group. Assistance from the Cumulative Effects work group on the issue in V. above would be helpful.

Mitigation Option: Reduced Vehicular Dust Production by Covering Lease Roads with Rock or Gravel

I. Description of the mitigation option

This mitigation option would involve reducing vehicular dust production by covering unpaved roads with rock or gravel. Benefits from this strategy include only dust reduction. Burdens would fall exclusively on the energy companies. These burdens would include obtaining the road material and paying crews to install it. Additionally, the presence of rock on the roads makes snow removal more difficult, and is hard on snow removal equipment. Therefore, road maintenance costs may increase during the winter months. Tradeoffs would include the pollutants emitted during the trucking and installation of the road material. Assistance is needed from the Cumulative Effects work group to estimate the net air quality gain from centralizing produced water storage facilities.

II. Description of how to implement

A. This mitigation option should be implemented on a voluntary basis. Forced implementation could hasten the uneconomic status of groups of wells resulting in premature abandonment of the wells and their hydrocarbon products.

B. The most appropriate agency to implement would be the environmental agency through permitting incentives/offsets. It would be necessary to first understand the relative environmental benefit of covering roads with rock (Cumulative Effects Work Group task).

III. Feasibility of the option

Technical – The technology exists today to implement this mitigation option.

Environmental – A study would need to be made to determine the relative emission reductions due to covering the roads with rock (Cumulative Effects Work Group task).

Economic – In some cases the implementation of this technology will be economically feasible. In others it will not be.

IV. Background data and assumptions used

While EPA does have AP-42 emission factor data available for unpaved roads (13.2.2), no input information was available in the time frame desired to make any calculations / determinations. Hence the high-level and qualitative analysis. (Cumulative Effects Work Group task?)

V. Any uncertainty associated with the option (Low, Medium, High)

High. Assistance from the Cumulative Effects work group would be needed to understand the relative emission reduction benefit from covering lease roads with rock. Once that is understood, an analysis could be made to reduce the economic and regulatory uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups (please describe the issue and which groups

It is believed that this issue may cross-over to the Other Sources work group.

Mitigation Option: Reduced Truck Traffic by Efficiently Routing Produced Water Disposal Trucks

I. Description of the mitigation option

This mitigation option would involve setting up a produced water hauler coordinating / dispatch service to route water haulers as efficiently as possible in order to reducing vehicular traffic on unpaved roads (and hence dust production). Much of the large truck traffic on unpaved lease roads is water haulers. Therefore, one strategy to reduce dust is to minimize water hauler traffic. To accomplish this goal, it would be necessary institute a central dispatch concept among all of the water haulers in the area such that (a) only full truckloads are hauled from a given area and (b) the water is hauled to the closest disposal facility possible. Benefits from this strategy include dust reduction, vehicle tailpipe exhaust emission reduction, and reduced vehicular fuel consumption (and therefore the need for crude oil feedstocks). Burdens would fall both on the water hauling service companies and on the water disposal companies. These burdens would include agreements to cooperate (which would include the setting of prices), the purchase of compatible radio equipment, and the implementation of a central dispatch facility. There would be no tradeoffs associated with this strategy. Assistance is needed from the Cumulative Effects work group to estimate the net air quality gain from optimizing produced water hauling routes.

II. Description of how to implement

This mitigation option could be implemented on a mandatory basis. In order to set fair prices on water hauling and disposal (like taxi cabs), it would be necessary to involve other agencies and potentially special legislation.

The most appropriate agency to implement would be the states' regulatory entity for the oil and gas industry. It would be necessary to first understand the relative benefit of reducing emissions from lease road traffic due to optimization (Cumulative Effects Work Group task).

III. Feasibility of the option

Technical – The technology exists today to implement this mitigation option.

Environmental – A study would need to be made to determine the relative benefit of reducing emissions from lease road traffic due to optimization (Cumulative Effects Work Group task).

Economic – Implementation of this technology should be economically feasible.

IV. Background data and assumptions used

No input information was available in the time frame desired to make any calculations / determinations. Hence the high-level and qualitative analysis. This could be a Cumulative Effects Work Group task.

V. Any uncertainty associated with the option (Low, Medium, High)

Low. Assistance from the Cumulative Effects work group would be needed to understand the relative environmental benefit of optimized truck traffic. Once that is understood, an analysis could be made to reduce the economic and regulatory uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other source groups (please describe the issue and which groups

It is believed that this issue will not cross-over to any other source work group.

Mitigation Option: Use Alternative Fuels and Maximize Fuel Efficiency to Control Combustion Engine Emissions

I. Description of the mitigation option
This option involves the implementation of alternative fuels, ultra low sulfur diesel (15 ppm) and improved fuel efficiency for heavy-duty trucks (Class 7 – GVW 26,001 to 33,001). The air quality benefits include potential reduction of sulfur, greenhouse gases and aromatic compounds throughout the region. Other environmental impacts include a reduction in petroleum consumption and conservation of natural resources.

Economic burdens include the cost of the new alternative fuel/fuel efficient vehicle and cost and availability of the fuel.

There would not be adverse environmental justice issues associated with the implementation of alternative fuels. There is potential for air quality improvements from travels through socio-economically disadvantaged communities with improved fuel efficiency.

Low sulfur diesel can continue to be used in 2006 and older highway vehicles until 2010. Any new 2007 model year highway diesel vehicle will be required to use ultra low sulfur diesel (ULSD). ULSD must be available at retail by October 15, 2006. Terminals should be turned over to ULSD by the end of July. They could consider using ULSD for the non-road equipment too and get even more reductions in PM as well.

II. Description of how to implement
A. Mandatory or voluntary: There may be some mandatory upgrades for new heavy-duty trucks purchased after a set date. The immediate move to alternative fuel vehicles should be a voluntary program and could be incorporated into the San Juan Vistas or similar program. Likewise the states could adopt tax advantaged strategies under a voluntary program to encourage the adoption of alternative fuels.
B. Indicate the most appropriate agency(ies) to implement**:** NM Dept. of Transportation, Colorado Dept. of Transportation, Federal Highway Administration.

III. Feasibility of the option
A. Technical: Oil and gas industry have developed a diesel fuel made from natural gas through the Fischer-Tropsch (F-T) process, there are other synthetic liquid fuels and major heavy-duty diesel engine companies are working on engines with reduced NOx and particulate emissions.
B. Environmental: The environmental benefits would primarily be associated with reduced consumption of petroleum resources.
C. Economic: The market will have to drive economically viable alternatives. According to referenced studies, Class 7 Heavy Duty Vehicles use a smaller percentage of fuel than Class 8 trucks (long-haul tractor- trailers), Class 2b vehicles (light trucks) or Class 6 vehicles (delivery vans).

IV. Background data and assumptions used
1. Life Cycle Analysis for Heavy Vehicles by Argonne National Laboratory Transportation Technology R&D Center.
2. Heavy Vehicle Technology and Fuels September 2004 – Argonne National Laboratories Transportation Technology R&D Center.
3. Green Machines facts and figures associated with fuel type, consumption rates, and emissions factors (reference)

V. Any uncertainty associated with the option High.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to other source groups None at this time.

Mitigation Option: Utilize Exhaust Emission Control Devices for Combustion Engine Emission Controls

I. Description of the mitigation option
This option involves the implementation of exhaust emission control devices for heavy-duty trucks (Class 7 – GVW 26,001 to 33,001) such as diesel oxidation catalysts (DOC), diesel particulate filters and/or traps. The air quality benefits include potential reduction of particulate matter and NOx throughout the region.

Economic burdens include the cost associated with the installation and maintenance of the exhaust emission control devices.

There would not be environmental justice issues associated with the implementation of emission controls.

II. Description of how to implement
A. Mandatory or voluntary: There may be some mandatory upgrades for new heavy-duty trucks purchased after a set date. The immediate move to emission controls should be a voluntary program and could be incorporated into the San Juan Vistas or similar program.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option
A. Technical: Technology exists.
B. Environmental: The environmental benefits would primarily be associated with reduced particulates and NOx.

Most devices are also effective at reducing VOCs, and therefore air toxics and ozone. In fact, the most common, inexpensive, and most demonstrated technologies are oxidation catalysts, which are more effective at removing VOCs than PM and NOx. After treatment technologies for reducing NOx (especially on mobile engines) are still evolving, and so strategies for reducing NOx typically rely on fuel emulsifiers, engine modifications/repair, and engine replacements.

C. Economic: The market will have to drive economically viable alternatives. According to referenced studies, Class 7 Heavy Duty Vehicles use a smaller percentage of fuel than Class 8 trucks (long-haul tractor- trailers), Class 2b vehicles (light trucks) or Class 6 vehicles (delivery vans).

IV. Background data and assumptions used
1. Life Cycle Analysis for Heavy Vehicles by Argonne National Laboratory Transportation Technology R&D Center.
2. Heavy Vehicle Technology and Fuels September 2004 – Argonne National Laboratories Transportation Technology R&D Center.
3. US EPA Clean Diesel and Trucks Rule
4. Green Machines facts and figures associated with fuel type, consumption rates, and emissions factors (reference)

V. Any uncertainty associated with the option (Low, Medium, High) High

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to other source groups

Mitigation Option: Exhaust Engine Testing for Combustion Engine Emission Controls

I. Description of the mitigation option
This option involves the implementation of an inspection and maintenance program to determine if emission controls and engines are functioning properly resulting in reduced emissions. Compliance with the standards set in the 2000 Heavy Duty Highway Clean Diesel Trucks and Buses Rule can be tested with an inspections and maintenance testing program. Environmental benefits include potential reduction of sulfur, NOx and particulates throughout the region.

Economic burdens include the cost of the inspection program, equipment, inspectors, and mobile or stationary inspection facilities.

There would not be environmental justice issues associated with the implementation of exhaust engine testing.

II. Description of how to implement
A. Mandatory or voluntary: Mandatory participation would be required.
B. Indicate the most appropriate agency(ies) to implement**:** NM Dept. of Transportation, Colorado Dept. of Transportation, Federal Highway Administration.

III. Feasibility of the option
A. Technical: Numerous states currently use exhaust emission testing. Details on mobile inspection programs are widely available.
B. Environmental: The environmental benefits would primarily be associated with reduced sulfur, particulates and compliance with Clean Diesel Trucks Rule.

Most devices are also effective at reducing VOCs, and therefore air toxics and ozone. In fact, the most common, inexpensive, and most demonstrated technologies are oxidation catalysts, which are more effective at removing VOCs than PM and NOx. After treatment technologies for reducing NOx (especially on mobile engines) are still evolving, and so strategies for reducing NOx typically rely on fuel emulsifiers, engine modifications/repair, and engine replacements.

C. Economic: The market will have to drive economically viable alternatives. According to referenced studies, Class 7 Heavy Duty Vehicles use a smaller percentage of fuel than Class 8 trucks (long-haul tractor- trailers), Class 2b vehicles (light trucks) or Class 6 vehicles (delivery vans).

IV. Background data and assumptions used
1. Life Cycle Analysis for Heavy Vehicles by Argonne National Laboratory Transportation Technology R&D Center.
2. Heavy Vehicle Technology and Fuels September 2004 – Argonne National Laboratories Transportation Technology R&D Center.
3. US EPA Clean Diesel and Trucks Rule
4. Green Machines facts and figures associated with fuel type, consumption rates, and emissions factors (reference)

V. Any uncertainty associated with the option (Low, Medium, High) Medium

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to other source groups None at this time.

Mitigation Option: Reduce Trucking Traffic in the Four Corners Region

I. Description of the mitigation option
This option involves implementing various measures to reduce the mileage required to truck fluids or equipment for oil and gas exploration, production, or treating operations. The air quality benefits include increased operating efficiency by 10% which will equate to 10% reduced fuel usage, which results in a net reduction of emissions of NOx by [ ] tons per day, SOx by [ ] tons per day, a reduction in greenhouse gas emissions of [ ] and PM2.5 emissions by [ ] tons per day. Other environmental impacts include reduced dust and noise from the trucks and roads at nearby residences, and reduced unintentional killing of wildlife and livestock that may be killed truck traffic.

Economic burdens include the cost of centralized facilities and systems designed to maximize routing efficiency, which may be partially offset by the benefits to human health of improved air quality and reduction of highway traffic (and traffic accidents) in the region.

There should not be any environmental justice issues associated with the placement of the centralized tank batteries (including produced water tanks, condensate tanks and/or crude oil tanks) in socio-economically disadvantaged communities.
Differing opinion: There are potential health hazards associated with crude oil and condensate tank emissions. Concentrating these facilities in socio-economically disadvantaged communities is an example of environmental injustice.

II. Description of how to implement
A. Mandatory or voluntary: The implementation of measures to maximize routing efficiency and reduce truck trips are envisioned as a "voluntary" measures to enhance operating efficiency and could be easily incorporated as a BMP in voluntary programs such as the NMED San Juan VISTAs program. Furthermore, the state could adopt tax advantages strategies to allow companies to reduce their taxes by showing reduced emissions from adopting improved routing or operating efficiency. There are currently no mechanisms or rules to require mandatory efficiency standards and this seems implausible as a mandatory approach.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option
A. Technical: The use of centralized facilities is technically feasible as is software to maximize routing efficiency.
B. Environmental: The environmental benefits of reduced vehicle mileage are well documented.
C. Economic: These options need to be explored by individual companies as to their economic viability.

IV. Background data and assumptions used
1. Water hauling is necessary in NM due to the lack of pipeline infrastructure to pipe the fluids directly to SWD facilities; Colorado has a greater use of pipelines.
2. Trucking companies will not react adversely to reduced economics from less vehicle miles.

V. Any uncertainty associated with the option Medium.

VI. Level of agreement within the work group for this mitigation option General agreement among drafting team members that this is viable and probable.

VII. Cross-over issues to other source groups None at this time.
Differing opinion: Some indication by the Cumulative Effects group of the potential emissions reduced would be helpful.

ENGINES: RIG ENGINES

Mitigation Option: Diesel Fuel Emulsions

I. Description of the mitigation option

Diesel Fuel Emulsions:

- This option, which is an EPA verified retrofit technology, reduces peak engine combustion temperatures and increases fuel atomization and combustion efficiency.
  Differing opinion: The EPA study only looked at the "summer" blend of diesel emulsion. There is no data available to evaluate neither the compatibility with winter temperatures nor the emissions effects at winter temperatures.
- It is accomplished by using surfactant additives to encapsulate water droplets in diesel fuel to form a stable mixture while ensuring that the water does not contact metal engine parts.
- Air quality benefit:

	% Reductions[2, 3]			
Non-Road [1]	PM	CO	NOx	HC
0-100 hp	23	(35)	19	(99)
100-175 hp	17	13	17	(80)
175-300 hp	17	13	19	(73)
>300 hp	17	13	20	(30)

1. Estimate using 2D fuel, <500 ppm sulfur.
2. (##) indicates an increase
3. Based on verification results supplied to EPA by Lubrizol for PuriNOx emulsion.
   Differing Opinion: CARB's verified NOx reductions were lower (14%) than EPA's as shown in the above table. This suggests a need for a more extensive review prior to finalizing this option.

- Can be used in conjunction with a diesel oxidation catalyst to reduce HC and CO emissions and further reduce PM.
- Emission control performance is better in lower load/lower speed applications.
- Emulsions have about a 12-month shelf life.
- Typically experience a 20% power loss when operating at maximum engine horsepower. The power loss is potentially a fatal flaw in this method. Most rig engines are sized for the maximum load expected and would have to be refitted with larger engines to handle the equivalent maximum loads.
- Will expect a 15% increase in fuel consumption for equipment operating on fuel with emulsion additive. [This will increase SO2 emissions by 15%. The mass will depend on the sulfur content of the fuel. It will also increase fuel delivery truck emissions by 15% along with road dust emissions due to fuel hauling by 15%.
- Not compatible with optical or conductivity-type fuel sensors, water absorbing water separators, water absorbing fuel filters, or centrifugal style water separators.
- Engine must be run for at least 15 minutes every 30 days.
- Incremental cost increase of $0.10 to 0.20 per gallon.
  Differing opinion: The increased fuel cost on top of the 15% increase in fuel consumption makes this a very expensive option. For a "typical" 16 day Wyoming Green River Basin well using 19,816 gallons of diesel, the 15% fuel penalty would represent about $6,000 additional fuel cost and the average premium ($0.15/gal) would represent about $3,400 additional fuel cost for a NOx benefit of about 1 ton reduction – or a cost of about $9,400 per ton of NOx. This seems very excessive and does not include the additional costs required for separate mixing and storage of the emulsified fuel. There may also be incremental labor costs for the technicians to operate the system. The incremental cost per gallon needs to be updated and verified – the cost quoted dates

to the original study date. Installation of oxidation catalyst to control hydrocarbon and CO emissions would add additional cost and complexity to an already cost prohibitive option.

- Requires mixing of fuel with emulsion and a storage unit for the emulsion and or mixed fuel. Some burden on technicians to properly operate and mix some simple equipment.

II. Description of how to implement

This voluntary option would be relatively simple using EPA verified retrofit technology. Some analysis is required to ensure that duty cycle (how long will engine and fuel be idle) and ambient temperatures are compatible with the emulsion product. Storage tanks and some training and capable technicians will be required to put into operation the relatively simple mixing equipment.

Differing opinion: The power penalties, incremental mixing and storage equipment, and increased technical knowledge necessary make this option do-able, but not necessarily simple.

III. Feasibility of the option

A. Technical: Technically this is one of the simplest options available.

B. Environmental: Fuel emulsion has potential for increased carbon monoxide and hydrocarbon emissions, but this downside could be overcome by use of a diesel oxidation catalyst. One additional issue with the emulsion option is that if the emulsion is no longer purchased or used the emission benefit goes away, in comparison to permanent exhaust treatments or improved engines or hardware.

C. Economic: There would be capital cost for emulsion and/or mixture storage and ongoing incremental cost per gallon.

Differing opinion: This option should be characterized as an expensive one. Using a “typical” 16 day Wyoming Green River Basin well using 19,816 gallons of diesel the 15% fuel penalty would represent about $6,000 additional fuel cost and the average premium ($0.15/gal) would represent about $3,400 additional fuel cost for a NOx benefit of about 1 ton reduction – or a cost of about $9,400 per ton of NOx. This seems very excessive and does not include the additional costs required for separate mixing and storage of the emulsified fuel. There may also be incremental labor costs for the technicians to operate the system.

IV. Background data and assumptions used

As an EPA verified retrofit, the data and assumptions associated with this option have been well evaluated and considered.

Differing opinion: The evaluation of applicability in cold weather needs to be done.

V. Any uncertainty associated with the option (Low, Medium, High)

Low uncertainty as this is a verified, simple retrofit.

Differing opinion: Given the high apparent cost, no evaluation in cold weather, different reduction percentages from separate evaluations, and complexity, this option should not be considered low uncertainty.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups (please describe the issue and which groups

None at this time.

Mitigation Option: Natural Gas Fired Rig Engines

<u>I. Description of the mitigation option</u>

Install natural gas fired engines on rigs in the Four Corners region.

Benefits

- Air Quality - Natural gas engines emit less and NOx,
  - ~ 85% reduction of NOx vs. Tier I engines.
    Differing opinion: Given the variable load (and often low load) on drilling rig engines, the "best" lean burn natural gas engine performance expected would be in the range of 2 to 3 grams per hp-hr. This represents about a 65-75% reduction from Tier 1 diesel engines. Please note this would require lean burn engines.
  - ~ 91% reduction of NOx vs. Tier 0 engines
    Differing opinion: Given the variable load (and often low load) on drilling rig engines, the "best" lean burn natural gas engine performance expected would be in the range of 2 to 3 grams per hp-hr. This represents about a 65-75% reduction from Tier 1 diesel engines. Please note this would require lean burn engines.
  - Natural gas engines emit less particulate matter (PM) on a larger percent reduction basis than the NOx percentages above.
- Cost Savings?
  - If the natural gas fuel source is in close proximity and little piping is required, its use may be less expensive than diesel, which is currently hauled to the rig.
    Differing opinion: On a purely fuel basis this may be true without considering the retrofit costs.
  - Savings in fuel cost is dependent on product price.

Tradeoffs

- CO levels increase with natural gas usage, ~ 175%

Burdens

- Fuel Source
  - A natural gas fuel source sufficient to power the rig engines may not be readily available at every site.
  - Installation of piping to transport the natural gas may increase safety risks for workers and may potentially require right-of-way that can significantly delay projects (months to years).
  - Natural gas usage may require mineral owner approval, metering and appropriate allocation potentially resulting in permitting delays and increased administrative support
  - Fuel supply needs careful tuning and monitoring due to varying amounts of produced water that may be present. Also impacted by variations in fuel quality in the different areas and formations of a field. Could also require the installation of a dehydrator if gas is wet and the field uses a central dehydration system.
  - Engine size must increase to achieve an equivalent horsepower yield. For example a Cat 3512 diesel would have to be replaced with a Cat 3516 natural gas engine to get approximately the same horsepower.
- Rig Operations
  - Slower power response and less torque requires learning curve on rigs
  - Not well suited for Mechanical Rigs – Electric rigs are preferred. Information from natural gas fueled engine rigs in Wyoming indicates that a "load bank" is required due to the slower response of the engines to power demand.
- Cost
  - Initial Capital Investment – up to 1.2 MM$ / Rig for retrofit

  - If the natural gas fuel source is distant or not available for other reasons, the associated piping or use of LNG may be significantly more expensive than diesel.
    Differing opinion: LNG is not a viable fuel – it is not readily available, requires refrigerated storage, and requires "re-gas" equipment. Conversion to natural gas fuels essentially limits the utility of a particular rig to just those instances where gas is available.
- Availability
  - Engine availability is limited

II. Description of how to implement
A. Mandatory or voluntary: Voluntary
B. Indicate the most appropriate agency(ies) to implement**:** None

III. Feasibility of the option
A. Technical: A natural gas fired rig engine is currently being utilized in Wyoming in the Jonah Field indicating that the technology works. However, the Jonah field is significantly different from the San Juan Basin enabling easier access to natural gas as a fuel source. The wells in the Jonah Field are more closely spaced (10 acre vs. 80 acre) and deeper allowing for the directional drilling of several wells from a single well pad and close proximity to currently producing wells.

B. Environmental: Installation of natural gas fired engines on new rigs will significantly reduce NOx emissions for those rigs, but may result in other environmental impacts, including an increase in CO emissions and potential land disturbance related to installation of natural gas pipelines to deliver the fuel.

C. Economic: In some cases where a natural gas fuel source is nearby, fuel costs may be lower than for diesel. In other cases, where access to natural gas can only be obtained by installing a large amount of pipe that potentially requires a right-of-way or by using LNG, the costs may be significantly higher. Conversion to natural gas fired engines essentially limits the use of a rig to only those instances where gas is available. The conversion/retrofit costs are high.
Differing opinion: See LNG comments above.

IV. Background data and assumptions used
Utilized Encana data obtained from Ensign 88 – Natural Gas Rig (2 3516 LE Natural Gas Engines on 1200 KW Generators)

V. Any uncertainty associated with the option (Low, Medium, High) High

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to other source groups

Mitigation Option: Selective Catalytic Reduction (SCR)

I. Description of the mitigation option

Selective Catalytic Reduction (SCR)

Description

Selective catalytic reduction (SCR) is the process where a reductant (typically ammonia or urea) is added to the flue gas stream and is absorbed onto the catalyst (typically vanadium or zeolite) enabling the chemical reduction of NOx to molecular nitrogen and water. Diesel engines typically have unconsumed oxygen in the exhaust, which inhibits removal of oxygen from the NOx molecules. To remove the unconsumed oxygen, the catalyst decomposes the reductant causing the release of hydrogen, which reacts with the oxygen. This creates local oxygen depletion near the catalyst allowing the hydrogen to also react with the NOx molecules to form nitrogen and water.

Benefits

- NOx emission reductions of 80-90% are achieved. NOx emission reductions of up to 80-90% are achievable.
- Potential to reduce hydrocarbon, hazardous air pollutant, and condensable particulate matter (PM) emissions based on emissions tests.
- Technology is available currently.
- SCR systems designed primarily to reduce NOx have been designed with PM filtering capabilities.

Tradeoffs

- Ammonia Slip

The SCR process requires precise control of the ammonia injection rate. An insufficient injection may result in unacceptably low NO_x conversions. An injection rate that is too high results in release of undesirable ammonia to the atmosphere. These ammonia emissions from SCR systems are known as *ammonia slip*. Ammonia slip will also occur when exhaust gas temperatures are too cold for the SCR Reaction to occur. Ammonia slip can potentially be controlled by an oxidation catalyst installed downstream of the SCR catalyst. Diesel oxidation catalysts are often used downstream of NOx catalysts for ammonia reduction.

Burdens

- Minimum and maximum temperature ranges limit the effectiveness of the SCR system.
  - The SCR system requires a minimum exhaust temperature of 572°F (300°C) and maximum of 986°F (530°C) for NOx reduction to occur (optimal range).
- The SCR systems had faults and system errors that can shut the urea injection system off.
  - ENSR testing had problems with the NO2 measuring cells that had multiple high and low pressure and measurement alarms.
- The SCR system needs operator attention.
  - The SCR system needs to be tuned to the engine operating cycle. This requires running the engine through a simulation of the operating cycle of the machine it will be fitted to (engine mapping).
  - Typically SCR catalysts require frequent cleaning even with pure reductants, as the reductant can cake the inlet surface of the catalyst while the exhaust gas stream temperature is too low for the SCR reaction to take place.
- Potential for ammonia slip
- Cost (Retrofit)
  - Capital Expenditure Costs - ~$130,000 / new SCR unit

– Operating Expenditure Costs - ~$143,000 / year / unit 1
– Costs extrapolated out over a 10-year period would equate to **$1.56 MM / engine equipped.**
– Need for reductant (NH_3) adds to the engine operating cost (in the range of 4% of the equipment operating fuel cost).

Non-Selective Catalytic Reduction (NSCR)
NSCR is not applicable to diesel engines.

II. Description of how to implement
A. Mandatory or voluntary: The workgroup believes that more information is required on the contribution of rig emissions to the total NOx emissions and the potential ammonia emissions impact to visibility prior to determining whether this mitigation should be mandatory or voluntary.
.
*B. Indicate the most appropriate agency(ies) to implement***:** The states.

III. Feasibility of the option
A. Technical: The technology is available and effective in reducing NOx emissions.
B. Environmental: Proven reduction of NOx emissions, however the potential increase of ammonia emissions and subsequent impact to visibility is not well understood.
C. Economic: Capital costs associated with a new engine with SCR or installation of retrofit SCR are feasible. Additional costs associated with operation and maintenance may not be feasible for some rig operators.

IV. Background data and assumptions used
Utilized information from ENSR Presentation - *Technology Demonstration – Selective Catalytic Reduction (SCR) and Bi-Fuels Implementation on Drill Rig Engines*

V. Any uncertainty associated with the option (Low, Medium, High)
Medium – It is clear that SCR is effective in reducing NOx emissions, however an understanding of the potential increase of ammonia emissions and the resulting impacts to visibility need to be understood.

VI. Level of agreement within the work group for this mitigation option
The workgroup agrees that this is a potential mitigation option, but requires more information regarding ammonia emissions and the overall contribution of NOx emissions from rigs.
EPA has SCR listed as a Potential Retrofit Technology for diesel engines.

VII. Cross-over issues to the other source groups (please describe the issue and which groups
Cumulative Effects Workgroup – The Rig Engines Drafting Workgroup requires information on the estimated contribution of NOx emissions from rig engines and on the impact of ammonia emissions on visibility (what are local levels currently, how will increasing ammonia emissions impact visibility?).

Mitigation Option: Selective Non-Catalytic Reduction (SNCR)

I. Description of the mitigation option
Selective Non-Catalytic Reduction (SNCR) is a post-combustion treatment in which ammonia is injected into the flue gas stream. The ammonia reacts with the NOx compounds, forming nitrogen and water. In order for this technique to be effective, the ammonia must be injected at a proper temperature range within the stack and must be in the proper ratio to the amount of NOx present. The reduction reaction at temperatures ranging from 925 – 1125ºC does not require catalysis and can achieve 40% NOx control. More modest NOx reductions are reported in the 725 - 925ºC range.
Differing Opinion: These are very high temperatures and much greater than the temperatures in diesel engine exhaust. For example, the data sheet for a Cat 3512 diesel rig engine shows a "highest" exhaust temperature of ~792 degrees F. Based on the degradation in performance reported in the 725 – 925 degrees C it probably would have very little effect at the exhaust temperatures from rig engines. This technology is really tested for very high temperature boilers only – not engines.

Benefits
- NOx emission reductions of ~40% (range 20-55%) are achieved in optimal temperature range.
- Avoids the expense of a catalyst.
- Technology is available currently.

Tradeoffs
- Ammonia Slip – 10 ppm ammonia slip is considered reasonable for SNCR. 10 ppm represents about 16 tons/yr of ammonia from a single fully loaded Cat 3512 engine. Given that most rigs have two or more engines it is not much of a stretch to have very significant ammonia emissions with the number of rigs running in the basin. This amount of ammonia may enhance secondary particulate formation with consequent effects on PM 2.5 (health based) and visibility (perception based).

Burdens
SNCR tends to have high operating costs - cost is estimated at $600 - $1300/ton
Mobile source engines (rig engines) are usually not a good candidate for SNCR because typical operating temperatures are below the levels needed for effective operation.

II. Description of how to implement
A. Mandatory or voluntary: The workgroup believes that more information is required on the contribution of rig emissions to the total NOx emissions and the potential ammonia emissions impact to visibility prior to determining whether this mitigation should be mandatory or voluntary.
B. Indicate the most appropriate agency(ies) to implement: Colorado Department of Public Health and Environment (CDPHE), New Mexico Environment Department (NMED).

III. Feasibility of the option
A. Technical: The technology is available and effective in reducing NOx emissions.
Differing Opinion: There is no available data indicating applicability to engines or much lower temp operation. This option should be considered as non-feasible.
B. Environmental: Proven reduction of NOx emissions, however the potential increase of ammonia emissions and subsequent impact to visibility is not well understood.
C. Economic: Costs associated with operation and maintenance may not be feasible for some rig operators.

IV. Background data and assumptions used
State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines – State of New Jersey, Department of Environmental Protection, Division of Air Quality

V. Any uncertainty associated with the option
Medium – SNCR is effective in reducing NOx emissions, however an understanding of the potential increase of ammonia emissions and the resulting impacts to visibility need to be understood.

VI. Level of agreement within the work group for this mitigation option
The workgroup agrees that this is a potential mitigation option, but requires more information regarding ammonia emissions and the overall contribution of NOx emissions from rigs.

VII. Cross-over issues to the other source groups
Cumulative Effects Workgroup – The Rig Engines Drafting Workgroup requires information on the estimated contribution of NOx emissions from rig engines and on the impact of ammonia emissions on visibility (what are local levels currently, how will increasing ammonia emissions impact visibility?).

Mitigation Option: Implementation of EPA's Non Road Diesel Engine Rule – Tier 2 through Tier 4 Standards

I. Description of the mitigation option

In short this option would require the use of engines that at minimum meet EPA Tier 2 non-road on a fleet average basis and that all newly installed engines would meet the most current EPA standard (Tier 2 through 4).

In 1998, EPA adopted more stringent emission standards ("Tier 2" and "Tier 3") for NOx, hydrocarbons (HC), and PM from new nonroad diesel engines. This program includes the first set of standards for nonroad diesel engines less than 50 hp (phasing in between 1999 and 2000), phases in more stringent "Tier 2" emission standards from 2001 to 2006 for all engine sizes, and adds more stringent "Tier 3" standards for engines between 50 hp and 750 hp from 2006 to 2008.

In June 2004, EPA adopted additional nonroad diesel engines emission standards. These standards are known as "Tier 4." This comprehensive national program regulates nonroad diesel engines and diesel fuel as a system. New engine standards will begin to take effect in the 2008 model year, phasing in over a number of years.

The pertinent regulations are as follows:

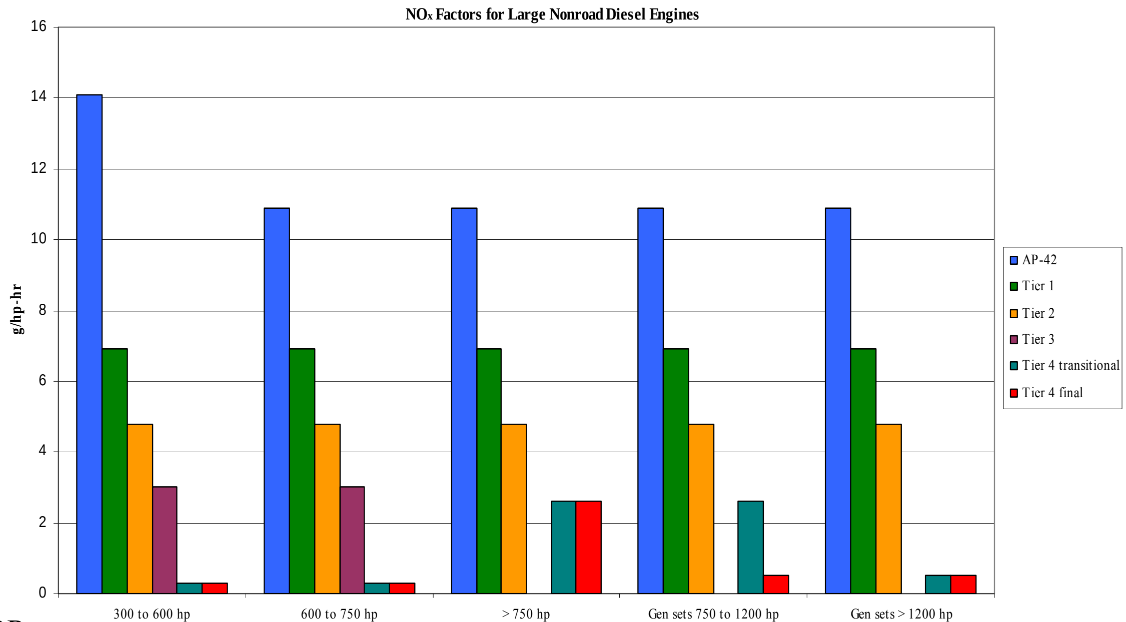
Clean Air Nonroad Diesel - Tier 4 Final Rule: Control of Emissions of Air Pollution from Nonroad Diesel Engines and Fuel, 69 FR 38957, June 29, 2004

Tier 2 and Tier 3 Emission Standards - Final Rule: Control of Emissions of Air Pollution from Nonroad Diesel Engines, 63 FR 56967, October 23, 1998

Drill rig engines would be considered "non-road engines" because of the definition of non-road engine in 40 CFR 1068.30 (1)(iii) and (2)(iii) – assuming the rig moves more often than every 12 months.

These non-road diesel standards do not apply to existing non-road equipment. Only equipment built after the start date for an engine category (1999- 2006, depending on the category) is affected by the rule.

The Tier 2, 3, and 4 Emission Standards for large (> 300 hp) are as follows: [AP42 (Tier 0) and Tier 1 shown for comparison purposes]



OR

	300 to 600 hp	600 to 750 hp	> 750 hp (Excluding Gen Sets)	Gen sets 750 to 1200 hp	Gen sets > 1200 hp
AP-42	14.1*	10.9**	10.9**	10.9**	10.9**
Tier 1	6.9	6.9	6.9	6.9	6.9
Tier 2	4.8	4.8	4.8	4.8	4.8
Tier 3	3	3			
Tier 4 transitional	0.3	0.3	2.6	2.6	0.5
Tier 4 final	0.3	0.3	2.6	0.5	0.5

*AP-42 Table 3.3-1 **AP-42 Table 3.4-1 shading -- NMHC + NOx

The Tier 2, 3, and 4 Emission Standards for large (> 300 hp) are as follows: [AP42 (Tier 0) and Tier 1 shown for comparison purposes]

Effective Dates of Tier Standards, Nonroad Diesel Engines, by Horsepower

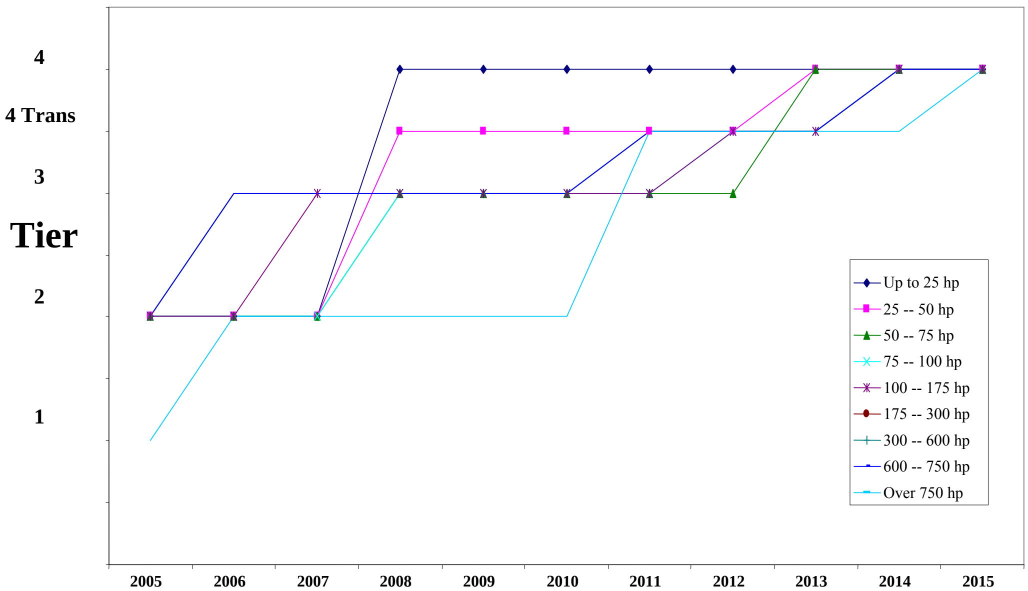


Table 1. Nonroad CI Engine Emission Standards[a]

Engine Power (hp)	Model Years	Regulation	Emission Standards (g/hp-hr)					NONROAD Tech Types
			HC [b]	NMHC+NO_x	CO	NO_x	PM	
<11	2000-2004	Tier 1		7.8	6.0		0.75	T1
	2005-2007	Tier 2		5.6	6.0		0.60	T2
	2008+	Tier 4					0.30	T4A, T4B [e]
≥11 to <25	2000-2004	Tier 1		7.1	4.9		0.60	T1
	2005-2007	Tier 2		5.6	4.9		0.60	T2
	2008+	Tier 4					0.30	T4A, T4B [e]
≥25 to <50	1999-2003	Tier 1		7.1	4.1		0.60	T1
	2004-2007	Tier 2		5.6	4.1		0.45	T2
	2008-2012	Tier 4 transitional					0.22	T4A
	2013+	Tier 4 final		3.5			0.02	T4
50 to <75	1998-2003	Tier 1				6.9		T1
	2004-2007	Tier 2		5.6	3.7		0.30	T2
	2008-2012	Tier 3 [c]		3.5	3.7			T3
	2008-2012	Tier 4 transitional [c]					0.22	T4A
	2013+	Tier 4 final		3.5			0.02	T4
≥75 to <100	1998-2003	Tier 1				6.9		T1
	2004-2007	Tier 2		5.6	3.7		0.30	T2
	2008-2011	Tier 3		3.5	3.7			T3B
	2012-2013	Tier 4 transitional	0.14 (50%) [d]			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N
≥100 to <175	1997-2002	Tier 1				6.9		T1
	2003-2006	Tier 2		4.9	3.7		0.22	T2
	2007-2011	Tier 3		3.0	3.7			T3
	2012-2013	Tier 4 transitional	0.14 (50%)			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N
≥175 to <300	1996-2002	Tier 1	1.0		8.5	6.9	0.4	T1
	2003-2005	Tier 2		4.9	2.6		0.15	T2
	2006-2010	Tier 3		3.0	2.6			T3
	2011-2013	Tier 4 transitional	0.14 (50%)			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N

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Engine Power (hp)	Model Years	Regulation	Emission Standards (g/hp-hr)					NONROAD Tech Types
			HC [b]	NMHC+NO_x	CO	NO_x	PM	
≥300 to <600	1996-2000	Tier 1	1.0		8.5	6.9	0.4	T1
	2001-2005	Tier 2		4.8	2.6		0.15	T2
	2006-2010	Tier 3		3.0	2.6			T3
	2011-2013	Tier 4 transitional	0.14 (50%)			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N
≥600 to ≤750	1996-2001	Tier 1	1.0		8.5	6.9	0.4	T1
	2002-2005	Tier 2		4.8	2.6		0.15	T2
	2006-2010	Tier 3		3.0	2.6			T3
	2011-2013	Tier 4 transitional	0.14 (50%)			0.30 (50%)	0.01	50% T4 50% T4N
	2014+	Tier 4 final	0.14			0.30	0.01	T4N
>750 except generator sets	2000-2005	Tier 1	1.0		8.5	6.9	0.4	T1
	2006-2010	Tier 2		4.8	2.6		0.15	T2
	2011-2014	Tier 4 transitional	0.30			2.6	0.075	T4
	2015+	Tier 4 final	0.14			2.6	0.03	T4N
Generator sets >750 to ≤1200	2000-2005	Tier 1	1.0		8.5	6.9	0.4	T1
	2006-2010	Tier 2		4.8	2.6		0.15	T2
	2011-2014	Tier 4 transitional	0.30			2.6	0.075	T4
	2015+	Tier 4 final	0.14			0.5	0.02	T4N
Generator sets >1200	2000-2005	Tier 1	1.0		8.5	6.9	0.4	T1
	2006-2010	Tier 2		4.8	2.6		0.15	T2
	2011-2014	Tier 4 transitional	0.30			0.5	0.075	T4
	2015+	Tier 4 final	0.14			0.5	0.02	T4N

[a] These standards do not apply to recreational marine diesel engines over 50 hp. Standards for this category are provided in Table 7.
[b] Tier 4 standards are in the form of NMHC.
[c] For 50 to <75 hp engines, a Tier 3 NO_x standard of 3.5 g/hp-hr was promulgated, beginning in 2008. The Tier 4 transitional standard also begins in 2008; it leaves the Tier 3 NO_x standard unchanged and adds a 0.22 g/hp-hr PM standard.
[d] Percentages are model year sales fractions required to comply with the indicated NO_x and NMHC standards, for model years where less than 100 percent is required.
[e] The T4A tech type is used in 2008-2012. The T4B tech type is used in 2013+.

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II. Description of how to implement

A. Mandatory or voluntary
Compliance with these regulations is required for new and rebuilt engines after the specified deadlines. The Four Corners Task Force is studying the potential for quicker implementation of the standards based on a voluntary agreement to either retrofit existing engines to meet the Tier 2 through Tier 4 standards or use of new Tier 2 through Tier 4 compliant engines.

B. Indicate the most appropriate agency(ies) to implement

EPA implements the non-road engine regulations nationally by certifying engine manufacture test results, but state regulatory agencies would be involved in any agreements for accelerated implementation of the standards in the Four Corners area.

III. Feasibility of the option

A. Technical
Some engine industry authorities indicate anecdotally that the supply of the new, cleaner engines may fall short of the demand for them particularly in the oil and gas industry.

In 1998, EPA adopted more stringent emissions standards for nonroad diesel engines. In that rulemaking, EPA indicated that in 2001 it would review the upcoming Tier 3 portion of those standards (and the Tier 2 emission standards for engines under 50 horsepower) to assess whether or not the new standards were technologically feasible. EPA drafted a technical paper with a preliminary assessment of the technological feasibility of the Tier 2 and Tier 3 emission standards - http://www.epa.gov/nonroad-diesel/r01052.pdf

In this assessment EPA determined that the standards were feasible with technologies such as the following:

Charge Air Cooling - Air-to-air or air-to-water cooling at intake manifold reduces peak temperature of combustion. (Controls NOx)

Fuel Injection Rate Shaping & Multiple Injections - Controls fuel injection rate, limiting rate of increase in temperature & pressure. (Controls NOx)

Ignition Timing Retard - Delays start of combustion, matching heat release with power stroke. (Controls NOx)

Exhaust Gas Recirculation - (1) Reduces peak cylinder temperature, (2) dilutes O_2 with inert gases, (3) dissociates CO_2 & H_2O endothermic. (Controls NOx)

B. Environmental
The Tier 2 and 3 standards will reduce emissions from a typical nonroad diesel engine by up to two-thirds from the levels of previous standards. By meeting these standards, manufacturers of new nonroad engines and equipment will achieve large reductions in the emissions (especially NOx and PM) that cause air pollution problems in many parts of the country. EPA estimates that by 2010, NOx emissions nationally will be reduced by about a million tons per year because of the Tier 2 and 3 standards.

When the full inventory of older nonroad engines are replaced by Tier 4 engines, annual emission reductions nationally are estimated at 738,000 tons of NOx and 129,000 tons of PM. By 2030, 12,000 premature deaths would be prevented annually due to the implementation of the proposed standards. EPA estimates that NOx emissions from these engines will be reduced by 62 percent in 2030.

C. Economic
EPA estimates the costs of meeting the Tier 2 and 3 emission standards are expected to add well under 1 percent to the purchase price of typical new non-road diesel equipment, although for some equipment the standards may cause price increases on the order of two or three percent. The program is expected to cost about $600 per ton of NOx reduced, which compares very favorably with other emission control strategies.

The estimated costs for added emission controls for the vast majority of equipment was estimated at 1-3% as a fraction of total equipment price. For example, for a 175 hp bulldozer that costs approximately $230,000 it would cost up to $6,900 to add the advanced emission controls and to design the bulldozer to accommodate the modified engine.

EPA estimated that the average cost increase for 15 ppm sulfur diesel fuel will be seven cents per gallon. This figure would be reduced to four cents by anticipated savings in maintenance costs due to low sulfur diesel.

IV. Background data and assumptions used (indicate if assistance is needed from Cumulative Effects and/or Monitoring work groups)

The Cumulative Effects group could assess how much air quality improvement would be realized from implementation of the Tier 2 through Tier 4 standards by a specified percent of rig engines in the Four Corners area, by timeframes specified in regulation or some accelerated schedule. The group could also address the number of days of visibility improvement, and the reduced flux of Nitrogen deposition.

V. Any uncertainty associated with the option (Low, Medium, High)

Low, these diesel engine standards must be met nationally by the specified dates. The primary uncertainty raised so far is related to supply of new engines sufficient to meet demand. EPA has studied the technological feasibility of the Tier 2 and Tier 3 emission standards and has determined that they are feasibility [see http://www.epa.gov/nonroad-diesel/r01052.pdf]

VI. Level of agreement within the work group for this mitigation option N.A. for complying with national regulations.

VII. Cross-over issues to the other source groups (please describe the issue and which groups
All new “non-road” diesel engines used in the Four Corners area will have to comply with these regulations.

Mitigation Option: Interim Emissions Recommendations for Drill Rigs

I. Description of the mitigation option

The following mitigation option paper is one of three that were written based on interim recommendations that were developed prior to the convening of the Four Corners Air Quality Task Force. Since the Task Force's work would take 18-24 months to finalize, and during this time oil and gas development could occur at a rapid pace, an Interim Emissions Workgroup made up of state and federal air quality representatives was formed to develop recommendations for emissions control options associated with oil and gas production and transportation. The Task Force includes these recommendations as part of its comprehensive list of mitigation options.

NOx emissions from drill rigs are significant on a year round basis and should be reduced by a requirement that rig engines meet Tier 2 standards.

- NOx emissions from rigs contribute to visibility degradation
- This recommendation is consistent with EPA Region 8's oil and gas initiative and recent Wyoming DEQ recommendations
- The requirement may be impractical for BLM to enforce

States should analyze potential initiatives to achieve emissions reductions from these sources to reduce deposition, the cumulative impacts to visibility, and to ensure compliance with the NAAQS and PSD increments.

II. Description of how to implement

NOx emission limits determined by Tier 2 would be mandatory for new rigs and voluntary for existing equipment. The agencies to enforce this would be BLM and the New Mexico and Colorado departments of environmental quality.

III. Feasibility of the Option

The feasibility of Tier 2 requirements for new rig engines has been demonstrated in commercial applications. The environmental benefits include PM and NOx reductions. The economic feasibility depends on using the technology with new rigs. The cost for replacement of an existing engine would be high since there might be no market for the used engine.

IV. Background data and assumptions used

The technology for rig engine upgrade to Tier 2 standards is based on the requirement to use Tier 2 certified diesel engines on new rigs. Under certain circumstances, upgrades might be required on older rigs as well.

V. Any uncertainty associated with the option

Tier 2 engines are currently being manufactured, but some uncertainty exists about the effectiveness of add-on controls to meet Tier 2 levels for existing rig engines.

VI. Level of agreement within the work group for this mitigation option

TBD.

VII. Cross-over issues to the other source groups

None.

Mitigation Options: Various Diesel Controls

Duel Fuel (or Bi-fuel) Diesel and Natural Gas; Biodiesel; PM Traps; Free Gas Recirculation; Fuel Additives; Liquid Combustion Catalyst; Lean NOx Catalyst; Low NOx ECM - Engine Electronic Control Module (ECM) Reprogram; Exhaust Gas Recirculation (EGR)

I. Description of the mitigation options

Duel fuel (or Bi-fuel) diesel and natural gas

This system allows engines to run on a blend of diesel and natural gas fuels. The systems consist of an air to fuel (AFR) controller and a fuel mixing chamber. The AFR constantly adjusts the fuel to air mixture being delivered to the piston chambers and optimizes the stoichiometric relationship in order to balance the NOx and CO emissions. The mixing chamber establishes the diesel to natural gas mixing ratio. This system is being tested on drill rig diesel engines in the Pinedale, WY area. There are preliminary results based on tests of three engines (Cat 398 & 399) Pros: Operators reported that rig engine fuel costs were reduced by ~ $700 per day, requires minimal engine modification, and has a small footprint. Cons: Does not conclusively reduce NOx, increases CO and HC emissions, and the system needs frequent oversight to ensure operation.

Biodiesel

Biodiesel fuel stock comes from vegetable oil, animal fats, and waste cooking oils. Biodiesel can be blended at different percentages up to100% (typically 5 – 20%). Biodiesel at a 20% blend can reduce PM mass emissions by up to 10%, reduce HC and CO up to 20%, and may slightly increase NOx emissions. Use of biodiesel requires little or no modification to fuel system or engine. Cold temperatures require special fuel handling such as additives or heating fuel system. EPA listed "verified retrofit technology."

PM Traps

Diesel particulate filters (DPFs) collect or trap PM in the exhaust. DPFs consist of a filter encased in a steel canister positioned in the exhaust system. DPFs need a mechanism to remove the PM (regeneration or cleaning) and to monitor for engine backpressure. DPFs types have different reduction capabilities and applications. DPFs can be used in conjunction with catalysts (catalyst based (CB) DPFs) to obtain the most effective PM control for a retrofit technology. CB-DPFs can have over 90% PM mass reduction and over 99% carbon based PM reduction. CB-DPFs can also control CO and HC resulting in near elimination of diesel smoke and odor.

Flow through filters (FTFs), or partial flow filters, use a variety of media and regeneration strategies. The filter media can be either wire mesh or pertubated path metal foil. FTFs are a relatively new technology. FTF can be catalyzed or used in combination with Diesel Oxidation Catalysts (DOCs) or Fuels Borne Catalysts (FBCs). PM reduction efficiencies range from 25 to over 60% depending on the type of technology and duty/test cycle. FTFs have the potential for greater application than conventional DPFs. Some designs can be used on engines fueled with < 500 ppm sulfur fuel but efficiency decreases. Has the potential for use on older engines, but high PM levels can overwhelm even a FTF system. Adequate exhaust temperatures are needed to support filter regeneration.

Diesel exhaust PM traps are EPA listed "verified retrofit technology."

Free Gas Recirculation

Crankcase emissions from diesel engines can be substantial. To control these emissions, some diesel engine manufacturers make closed crankcase ventilation (CCV) systems, which return the crankcase blow-by gases to engine for combustion. CCV systems prevent crankcase emissions from entering the atmosphere. Aftermarket open crankcase ventilations (OCV) are available which provide incremental improvements over engines with no crankcase controls, but they still allow crankcase emissions to be released into the atmosphere. A retrofit CCV crankcase emission control (CCV) system has been introduced and verified for on-road applications by both the U.S EPA and CARB. Crankcase emissions range from 10% to 25% of the total engine emissions, depending on the engine and the operating duty cycle. Crankcase emissions typically contribute to a higher percentage (up to 50%) of total engine emissions when the engine is idling. The combined CCV/DOC system controls PM emissions by up to 33%, CO emissions by up to 23% and HC emissions by up to 66%.

Fuel Additives
Fuel additives are chemical added to the fuel in small amounts to improve one or more properties of the base fuel and/or to improve the performance of retrofit emission control technologies. Several cetane enhancers have been verified by EPA that reduce NOx 0 to 5%. Other additives are undergoing verification. There thousands of fuel additives on the market that have no emission or fuel efficiency benefit so it is important to verify the manufacturer's claims regarding benefits. EPA listed "verified retrofit technology."

Liquid Combustion Catalyst
Fuels borne catalyst systems (FBCs) are marketed as a stand-alone product or as part of a system combined with DPFs, FTFs, or DOCs. FBCs have included cerium, cerium/platinum copper, iron/strontium, manganese and sodium. A DPF must be used to collect the catalyst additive so it cannot be emitted to the air. A FBC/DOC system has been verified by EPA to reduce PM 25 – 50%, NOx 0 – 5%, and HC 40 – 50%. A FBC/FTF system has been verified by EPA to reduce PM 55 – 76%, CO 50 – 66%, and HC 75 – 89%. The estimated cost of the verified FBC is approximately $.05 per gallon. Pre-mixed fuel is recommended for retrofit applications. FBCs do not require ultra low sulfur diesel and work with a wide range of engine sizes and ages. EPA listed "verified retrofit technology."

Lean NOx Catalyst
Lean NOx catalyst (LNC) is a flow through catalyst technology similar to diesel oxidation catalyst that is formulated for NOx control. It typically uses diesel fuel injection ahead of the catalyst to serve as NOx reduction. Lean NOx catalyst can achieve a 10% to over 25% NOx reduction. It can be combined with diesel oxidation catalyst (DOC) or diesel particulate filter (DPF). Over 3500 vehicles and equipment have been retrofitted with Lean NOx catalyst and CB-DPF filter systems in United States. The sulfur lever level of the fuel has to be less than 15 ppm. Verified LNC systems use injected diesel fuel as the NOx reducing agent and as a result a fuel economy penalty of up to 3% has been reported**.** EPA listed "potential retrofit technology."

Low NOx ECM - Engine electronic control module (ECM) reprogram
Some engine manufacturers used ECM on 1993 through 1996 heavy-duty diesel engines that caused the engine to switch to a more fuel-efficient but higher NOx mode during off cycle engine highway cruising. As part of the manufacturers' requirements to rebuild or reprogram older engines (1993-1998) to cleaner levels, companies developed a heavy-duty diesel engine software upgrade (known as an ECM "reprogram", "reflash" or "low NOx" software) that modifies the fuel control strategy in the engine's ECM to reduce the excess NOx emissions. Low NOx ECM is available as a retrofit strategy to reduce NOx emissions from certain diesel engines. Emissions control performance is engine specific. A system verified for a Cummins engine by CARB provided 85% particulate and 25% oxidation reductions. Over 60,000 heavy-duty diesel engines have received ECM reprograms. CARB plans to require ECM reprogramming on approximately 300,000 to 400,000 engines. ECM application is limited to heavy-duty diesel engines with electronic controls. Most off-road engines are not equipped with electronic controls. ECM is available throughout the U.S. through engine dealers and distributors. The software can be installed on-site and the reprogram takes approximately 15 to 30 minutes.

Exhaust Gas Recirculation (EGR)

The EGR system used in retrofit applications employs low-pressure. Original Equipment EGR systems typically employ high-pressure. EGR as a retrofit strategy is a relatively new development but has been proven durable and effective over the last few years. In the U.S. retrofit low-pressure EGR systems is combined with a CB-DPF to allow the proper functioning of the EGR component. EGR can reduce the NOx formed by the CB-DPF. EGR/DPF systems have been verified by CARB. Over 3000 and exhaust gas recirculation diesel particular filter systems have been retrofitted onto on road vehicles worldwide. EGR/DPF systems can be applied to off-road engines. However, experience is limited and the off-road market not the primary target application in the U.S. Current experience with EGR/DPF systems has been a range of 190 horsepower to 445 horsepower. The fuel economy penalty from EGR component ranges from 1% to 5% based on technology designed to particular engine and the test/duty cycle. EPA listed "potential retrofit technology."

II. Description of how to implement

These controls would be voluntary retrofits for existing engines. Some of these controls may be used by engine manufacturers to meet EPA's diesel standards for new engines.

III. Feasibility of the option

A. Technical
B. Environmental
C. Economic

See the individual control summary descriptions above. For more detailed information consult Volume 2 of the WRAP Off-road Diesel Retrofit Guidance Document, to be found at: http://www.wrapair.org/forums/msf/projects/offroad_diesel_retrofit/Offroad_Diesel_Retrofit_V2.pdf

IV. Background data and assumptions used

As EPA verified retrofits or potential retrofits (with the exception of the bi-fuel option), the data and assumptions associated with this option have been evaluated and considered. See EPA's Voluntary Diesel Retrofit Program web pages (http://www.epa.gov/otaq/retrofit/retroverifiedlist.htm and http://www.epa.gov/otaq/retrofit/retropotentialtech.htm) and Volume 2 of the WRAP Off-road Diesel Retrofit Guidance Document, located at: http://www.wrapair.org/forums/msf/projects/offroad_diesel_retrofit/Offroad_Diesel_Retrofit_V2.pdf for more information on these verified and potential retrofit controls.

V. Any uncertainty associated with the option

Low to high uncertainty depending on the application, engine, operating conditions. These are EPA verified or potential retrofits for diesel engines (with the exception of the bi-fuel option), but some controls are limited to specific applications.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

All existing or newly introduced diesel engines (on-road, non-road, and stationary) used in the 4 Corners area could utilize these control options with the limitations noted above.

ENGINES: TURBINES

Mitigation Option: Upgrade Existing Turbines to Improved Combustion Controls (Emulating Dry LoNOx Technology)

I. Description of the mitigation option
This option involves upgrading older units with improved electronic combustion control technology that approaches or meets Dry LoNOx for existing turbines and requires Dry LoNOx technology on all new turbines. The benefits of this mitigation option are lower NOx emissions, but it is an expensive option that may take several years to implement and may be difficult to achieve with some engine models. The tradeoffs is that a few people may spend a lot of money and not significantly impact overall nitrogen oxide emissions to meet the region's emission control objectives.

II. Description of how to implement
A. Mandatory or voluntary: Implementation should be assumed as voluntary until the existing turbine population is better understood.

Differing Opinion: The best technology should be mandatory.

B. Indicate the most appropriate agency(ies) to implement Federal, state, and tribal agencies responsible for air emissions compliance.

III. Feasibility of the option
A. Technical Individual turbine assessment will be needed to confirm appropriate size or design limitations (not all turbines can be retrofitted).
B. Environmental The benefits of a dry LoNOx emissions control technology on air emissions has been proven repeatedly for many large turbines.
C. Economic The economic impact cannot be understood without an inventory of installed turbines.

IV. Background data and assumptions used
No assumptions have been made at this time on the impact of emissions reductions due to the uncertainty of the existing turbine population.

V. Any uncertainty associated with the option High.

VI. Level of agreement within the work group for this mitigation option High.

VII. Cross-over issues to the other source groups
The impact of implementing this option may be further evaluated by the Cumulative Effects or Monitoring groups.

EXPLORATION & PRODUCTION: TANKS

Mitigation Option: Best Management Practices (BMPs) for Operating Tank Batteries

I. Description of the mitigation option
This option involves implementing and/or adoption of various Best Management Practices (BMPs) for operating tanks that contain crude oil and condensate. The specific BMPs include the use of Enardo valves, closing thief and other tank hatches, maintaining valves in leak-free condition, closing valves, etc. so as to minimize VOC losses to the atmosphere.

Economic burdens are minimal since these practices are largely followed and considered a normal cost of doing business as part of responsible operations.

There should not be any environmental justice issues associated with following these practices in socio-economically disadvantaged communities.
Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement
A. Mandatory or voluntary: The implementation of measures to implement BMPs for operating tank batteries are envisioned as "voluntary" measures to enhance operating efficiency and could be easily incorporated as a BMP in voluntary programs such as the NMED San Juan VISTAS program and EPA's Natural Gas STAR Program. There are currently no mechanisms or rules to require BMPs as standards, and this seems implausible as a mandatory approach. Many companies have BMPs in place already.

B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option
A. Technical: The use of BMPs for operating tank batteries is technically feasible as is software to maximize routing efficiency.
B. Environmental: The environmental benefits of reduced VOC pollution are well documented.
Differing opinion: Quantification of emission reductions from implementation of this mitigation option is not possible.
C. Economic: These BMPs need to be explored by individual companies as to their economic viability.

IV. Background data and assumptions used
1. Tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the lack of pipeline infrastructure to pipe the fluids directly to refineries.
2. Oil and gas producing companies will need to educate their workforce on the validity and importance of these BMPs.
3. Employees will not react adversely to following these practices as a normal course of being a lease operator.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option
General agreement within working group members that this is viable and probable.

Mitigation Option: Installing Vapor Recovery Units (VRU)

I. Description of the mitigation option

This option involves using Vapor Recover Units (VRUs) on crude oil and condensate tanks so as to capture the flash emissions that result when crude oil or condensate is dumped into the tank from the production separator. The air quality benefits would be to minimize VOC losses to the atmosphere and if sufficient flash gas were present, there would be economic benefits as well.

Economic burdens are substantial since these units are costly to install and maintain.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.
Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to implement VRUs for operating tank batteries are envisioned as "voluntary" measures since the feasibility of VRUs in the Four Corners area is negative. In certain areas of the country where ozone non-attainment areas exist, VRUs are commonly mandated by the respective Air Quality Control agency as Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER). Since the Four Corners area is not in ozone non-attainment and the costs economics will not generally justify installation of VRUs for economic benefit, a voluntary approach is recommended.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option

A. Technical: The use of VRUs for operating tank batteries is technically feasible.
Differing opinion: However, installation of a VRU to most existing tank installations is not likely feasible without a complete redesign and new installation. Most tanks are pressure rated at 3-5 psig and would need to be replaced with tanks designed with higher pressure rating to handle pressure surges during separator dumps. Additional pressure relief valving, pressure regulators and other safety devices would need to be included with these systems. Redesign and system replacement would need to be evaluated to determine the economic feasibility of this type of system. As these tanks are under pressure there would be additional operational and safety issues related to proper product transfer and handling. Most transporters are not equipped to handle pressurized product transfers at present. Due to the small amount of condensate produced in 4-Corners wells, the periodic "dumping" from the separators to the tanks, and the consequent uneven flash of gas from the condensate the use of VRU's is technically very challenging and may not be technically feasible. VRU's start from atmospheric pressure and boost gas to low pressure that may not be sufficient to flow into the collection system lines. In this case, they are either not feasible or would require additional compression. The lack of electricity in the fields effectively precludes any operationally feasible VRU use.

B. Environmental: The environmental benefits of reduced VOC pollution are well documented. Benefits are relative to production throughputs. VOC emissions from flashing emissions are a function of well pressure and condensate production. The amount of emission reduction will be proportional to the amount of uncontrolled VOC emissions. Even if VRU's can be made to work in the 4-corners area, the amount of VOC emission reduction per tank will be low due to the low condensate production rate.

C. Economic: The use of VRUs for recovering the flash emissions from produced crude oil/condensate are economically feasible where the Gas Oil Ratio (GOR) from produced crude oil/condensate is high and the daily production volume is at least 50 barrels/day or greater. Most wells in the Four Corners area typically produce less than 1 bbl/day of crude oil or condensate so VRUs are not economically feasible.

Flares or combustors could be considered an alternative control technology if sufficient VOC emissions exist. At 1 bbl/day and low pressure drop the flash gas volume and VOC content will not justify control systems.

IV. Background data and assumptions used
1. Tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the lack of pipeline infrastructure to pipe the fluids directly to refineries.
2. The minimal production levels for most wells make the use of VRU economically infeasible.

V. Any uncertainty associated with the option Low.
Differing opinion: MEDIUM based on availability of power, high maintenance requirements and reliability/performance.
Differing opinion: This would rank a high level of uncertainty in actually achieving meaningful and cost effective emission reductions using this technology.

VI. Level of agreement within the work group for this mitigation option
General agreement within working group members that the use of VRUs in the Four Corners areas is economically infeasible and an unlikely source for voluntary adoption.

Mitigation Option: Installing Gas Blankets Capability

<u>I. Description of the mitigation option</u>
This option involves modifying existing and installing new designed crude oil and condensate tanks that would be capable of placing an inert gas blanket over these tanks to minimize vapor loss. The inert gas would fill the space above the condensate/crude oil to minimize volatilization and vapor loss. The air quality benefits would be to minimize VOC losses to the atmosphere and if sufficient flash gas if present, there would be economic benefits as well.

Economic burdens are substantial since these units are costly to install and maintain.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.
Differing opinion: This conclusion requires adequate support that is not included in this option.

<u>II. Description of how to implement</u>
<u>A. Mandatory or voluntary:</u> The implementation of measures to implement gas blankets for operating tank batteries are envisioned as "voluntary" measures since the feasibility of gas blanket technology in the Four Corners area is negative. In certain areas of the country where ozone non-attainment areas exist, gas blanket technology is one of several measures commonly mandated by the respective Air Quality Control agency as Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER). Since the Four Corners area is not in ozone non-attainment and the cost economics will not generally justify installation of gas blankets for economic benefit, a voluntary approach is recommended.
<u>B. Indicate the most appropriate agency(ies) to implement</u>**:** The states.

<u>III. Feasibility of the option</u>
<u>A. Technical:</u> The use of gas blankets for operating tank batteries is technically feasible but requires the tanks to be designed to handle the increased pressures that will result when crude oil/condensate enters the tank, thereby pressurizing the gas blanket. Currently crude oil/condensate tanks are designed as atmospheric tanks and are designed only to withstand 5 psig of internal pressure. API 12F specifies 16 oz of pressure for normal operation and no greater than 24 oz for emergency operations. Using gas blanket technology requires such tanks to withstand about 100 psig, which increases the costs for tanks substantially. As these tanks are under pressure there would be additional operational and safety issues related to proper product transfer and handling. Most transporters are not equipped to handle pressurized product transfers at present.
<u>B. Environmental:</u> The environmental benefits of reduced VOC pollution are well documented.
Differing opinion: If this is considered a candidate control technology, the detailed engineering and economic analyses are needed to evaluate the cost to control relative to other potential control measures.
<u>C. Economic:</u> The use of gas blanket technology for preventing the release of flash and vapor emissions from produced crude oil/condensate are economically feasible for large, centrally located tank batteries where the crude oil/condensate can be piped from numerous wells to a centralized facility. Most wells in the Four Corners area typically produce less than 1 bbl/day of crude oil or condensate so the use of pipelines to transport the crude oil/condensate to a centralized facility is uneconomic.

<u>IV. Background data and assumptions used</u>
1. Individual tank batteries rather than large, centralized tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the minimal daily production volumes (i.e., less than 1 barrel/day).

<u>V. Any uncertainty associated with the option</u> Low.

Differing opinion: HIGH based on feasibility comments above and additional regulatory requirements for pressurized vessels, transport of pressurized product, and added safety processes.

VI. Level of agreement within the work group for this mitigation option

General agreement within working group members that the use of gas blanket technology in the Four Corners areas is economically unfeasible and an unlikely source for voluntary adoption.

Mitigation Option: Installing Floating Roof Tanks on Tanks in the Four Corners Region

I. Description of the mitigation option

This option involves using floating roof tanks on crude oil and condensate tanks so as to prevent the loss of emissions that result from crude oil or condensate stored in the tank. The air quality benefits would be to minimize VOC losses to the atmosphere and if sufficient gas were present, there would be minimal economic benefits. However, the use of floating roof tanks on smaller tanks instead of fixed roof tanks do not reduce the emissions. The emissions actually increase.

Economic burdens are substantial since these units are costly to install and maintain.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to implement floating roof tanks on tank batteries are envisioned as "voluntary" measures since the feasibility of floating roof tanks in the Four Corners area is negative. At certain facilities in the country where tanks are considerably larger are commonly mandated by the respective Air Quality Control agency as BACT or LAER. The common sizes of tanks in the Four Corners area will not benefit economically or in emission reductions through installation of floating roof tanks. Generally, emissions will increase if floating roofs are installed on these small tanks. Therefore, this mitigation does not have merit for the Four Corners area and is recommended not to be implemented either voluntary or mandatory.

B. Indicate the most appropriate agency (ies) to implement**:** NMED, Colorado Air Pollution Control Division.

III. Feasibility of the option

A. Technical: The use of floating roof tanks on tank batteries is technically feasible, however, not currently available for smaller sized tanks.

B. Environmental: The environmental benefits of reduced VOC pollution are well documented for larger tanks; however the documentation on smaller tanks with fixed roofs indicates an increase in emissions.

C. Economic: The use of floating tank roofs for preventing the working loss emissions from produced crude oil/condensate is not economically feasible.

IV. Background data and assumptions used

1. Tank batteries containing crude oil and condensate are necessary in NM and Colorado due to the lack of pipeline infrastructure to pipe the fluids directly to refineries.
2. The minimal production levels for most wells make the use of floating rank roofs economically infeasible.

V. Any uncertainty associated with the option (Low, Medium, High) Low

VI. Level of agreement within the work group for this mitigation option.

General agreement within working group members is that the use of floating tank roofs in the Four Corners areas is economically infeasible and an unlikely source for voluntary adoption.

EXPLORATION & PRODUCTION: DEHYDRATORS/SEPARATORS/HEATERS

Mitigation Option: Replace Glycol Dehydrators with Desiccant Dehydrators

I. Description of the mitigation option

Desiccant dehydrators utilize moisture-absorbing salts to remove water from natural gas. Desiccants can be a cost-effective alternative to glycol dehydrators. Additionally, there are only minor air emissions from desiccant systems.

Desiccant dehydrators are very simple systems. Wet gas passes through a “drying” bed of desiccant tablets (e.g., salts such as calcium, potassium or lithium chlorides). The tablets pull moisture from the gas, and gradually dissolve to form a brine solution. Maintenance is minimal - the brine must be periodically drained to a storage tank, and the desiccant vessel must be refilled from time to time. Often, operators will utilize two vessels so that one can be used to dry the gas when the other is being refilled with salt.

Desiccant dehydrators have the benefit of greatly reducing air emissions. Conventional glycol dehydrators continuously release methane, volatile organic compounds (VOC) and hazardous air pollutants (HAP) from reboiler vents; methane from pneumatic controllers; CO_2 from reboiler fuel; and CO_2 from wet gas heaters. The only air emissions from desiccant systems occur when the desiccant-holding vessel is depressurized and re-filled – typically, one vessel volume per week.[1] Some operators have experienced a 99% decrease in CH_4/VOC/HAP emissions when switching over to a desiccant system.[2]

Other potential benefits of desiccant dehydrators include: reduced ground contamination; reduced fire hazard; low maintenance requirements (because there are no moveable parts to be replaced and maintained); and the elimination of an external power supply.[3]

Solid desiccants are commonly used at centralized natural gas plants, but glycol dehydrators are still the most popular form of dehydration used in the field.[4] Most probably this is because there are particular conditions under which desiccant dehydrators work best:

- **The volume of gas to be dried is 5 MMcf/day or less.** Many wells in the San Juan Basin average less than 5 MMcf/day,[5] so this should not be a constraint to using desiccant systems.
- **Wellhead gas temperature is low (< 59º F for CaCl and < 70º for LiCl)**. If the inlet temperature of the gas is too high, desiccants can form hydrates that precipitate from the solution and cause caking and brine drainage problems. It is possible to cool or compress gas to the appropriate temperatures, but this increases the cost of the desiccant system.
- **Wellhead gas pressure is high (> 250 psig for CaCl and >100 psig for LiCl).**

II. Description of how to implement

A. Mandatory or voluntary

Where feasible, it should be mandatory, since it is both cost effective and virtually eliminates air emissions from field dehydrators.

Differing opinion: Cost is prohibitive for replacement of existing systems but applicable for new installations as determined on a case-by-case evaluation.

B. Indicate the most appropriate agency(ies) to implement

Dehydration is not a down-hole issue, therefore, is not the sole purview of the oil and gas commissions. Furthermore, this option relates specifically to minimizing air emissions. Thus, the most appropriate agencies to implement this option would be the environment/health agencies in the different states.

Differing opinion: The Federal area source MACT rules address glycol dehydrators and require controls for those whose size and throughputs justify control. This regulation was carefully considered and evaluated by EPA prior to finalization and should not be exceeded without careful analysis and justification.

III. Feasibility of the option

A. Technical

Desiccant dehydration is currently feasible under certain operating conditions (i.e., temperature and pressure of inlet gas). It may be possible to expand the applicability with add-on technologies (e.g., auto-refrigeration units to chill the inlet gas).[6]

Differing opinion: On March 20, 2007 at the NMOCD Greenhouse Gas meeting held in Santa Fe, NM, an operator stated during his presentation that based on their company's experience with salt dehydration in Wyoming, they are removing all salt dehydrators from service. Although the economics and technical feasibility initially looked very favorable, they have found salt slippage and other operational concerns very problematic with no technical solutions to date. Thus this method of dehydration is currently not as viable for their operations. This technology needs to be thoroughly considered before adoption – although it looks good initially, long-term use has not proven to be sustainable.

B. Environmental

Under some environmental conditions (e.g., high temperatures) this option becomes less feasible. Wastewater by product would need to handled, disposed of or re-injected. In the CBM areas of Colorado the gas is predominately methane and the gas is relatively dry and requires little dehydration. In this case VOC emissions are minimal. Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required. As a result of the type of production in this region it is likely that dehydration emissions are not significant and the use of such alternative technology may not be warranted.

C. Economic

For new dehydration systems, desiccant systems have been shown to be a lower cost alternative (both for capital and operating costs) than glycol dehydrators.[7] The payback period to replace an existing glycol dehydrator with a desiccant system has been shown to be less than 3 years.[8] The economics stated are only valid for a small range of temperature, pressure, and water content combinations. Desiccant dehydration for hot, low pressure, or high water content gas streams is not cost effective when compared to glycol dehydration.

Differing opinion: Increased operational costs for the desiccant, storage, and handling/disposal of wastewater should be factored in to the economics.

IV. Background data and assumptions used See endnotes.

V. Any uncertainty associated with the option Low.

Differing opinion: MEDIUM-HIGH based above comments regarding generation of wastewater, disposal, and recent operational experiences in Wyoming.

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other Task Force work groups

Notes:

1. U.S. Environmental Protection Agency. Natural Gas STAR Program. "Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators." p. 5. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf

2. U.S. Environmental Protection Agency. Natural Gas STAR Program. "Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators." p. 1. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf
3. Acor, L. Design Enhancements to Eliminate Sump Recrystalization in Zero-Emissions Non-Regenerative Desiccant Dryer. In: The Tenth International Petroleum Environmental Conference, Houston, TX. November 11-14, 2003 http://ipec.utulsa.edu/Conf2003/Papers/acor_78.pdf
4. Smith, Glenda, American Petroleum Institute, written comments to Dan Chadwick, USEPA/OECA, September 22, 1999. In. EPA Office of Compliance. Oct. 2000. Sector Notebook Project - Profile of the Oil and Gas Extraction Industry. EPA/310-R-99-006. p. 31
5. Lippman Consulting. May 16, 2005. "Production levels increase in San Juan Basin," Energy Quarterly. http://www.businessjournals.com/ artman/publish/article_898.shtml
6. U.S. EPA. Natural Gas Star. Replace Glycol Dehydrator with Separators and In-Line Heaters. PRO Fact Sheet No. 204.
   http://www.epa.gov/gasstar/pdf/pro_pdfs_eng/replaceglycoldehydratorwithseparators.pdf
   Auto-refrigeration has been used in other oilfield applications, such as chilling gas to enhance water condensation and separation.
7. U.S. Environmental Protection Agency. Natural Gas STAR Program. "Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators." p. 16. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf
   For a system processing 1 MMcf/day natural gas, operating at 450 psig and 47 F:
   Total implementation (capital plus installation): $22,750 (desiccant) vs. $35,000 (glycol)
   Total annual operating costs: $3,633 (desiccant) vs. $4,847 (glycol)
8. U.S. Environmental Protection Agency. Natural Gas STAR Program. "Lessons Learned - Replacing Glycol Dehydrators with Desiccant Dehydrators." p. 17. http://epa.gov/gasstar/pdf/lessons/ll_desde.pdf
   This payback period was reported for a glycol dehydrator system that was replaced with a two-vessel desiccant dehydration system.

Mitigation Option: Installation of Insulation on Separators

I. Description of the mitigation option
This option involves modifying existing and installing new separators that are insulated so as to reduce fuel usage. The air quality benefits would be to minimize combustion emissions to the atmosphere (NOx, CO, NMHC).

Economic burdens are significant but not insurmountable if the cost recovery factor from reduced fuel usage over the anticipated life of the unit shows a positive return on investment.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.
Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement
A. Mandatory or voluntary: The implementation of measures to implement insulated separators and vessels are envisioned as "voluntary" measures since the feasibility of installing insulation on new units or retrofitting existing units must be evaluated for a positive Net Present Value (NPV) or Return on Investment (ROI) in the Four Corners area. If the NPV or ROI meets a company's investment targets, then utilization of this technology should be encouraged as a best practice. There are no existing mandates by the respective Air Quality Control agencies to require insulated vessels as BACT. Since the Four Corners area is not in ozone non-attainment and the cost economics will not always justify installation of insulation for economic benefit, a voluntary approach is recommended.
B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option
A. Technical: The application of insulation to separators, tanks, or other heated vessels is technically feasible. Currently some companies are insulating newly installed on production separators and larger produced water tanks on a case-by-case basis.
B. Environmental: The environmental benefits of reduced NOx, CO, and NMHC pollution are well documented.
Differing opinion: It is unclear how much insulation would cut fuel consumption and consequently reduce emissions. The emissions from well-site production units are very small (the units are very small) and not a significant component of the regional NOx budget. Insulation of these units would make a small reduction in a very small number.
C. Economic: The application of insulation to separators, tanks, or other heated vessels for reducing fuel usage and minimizing combustion emissions from separators, tanks, or other heated vessels are economically feasible where the there is payback that meets the respective companies targets for investments (i.e., ROI or NPV). For older units or vessels where the remaining life of the equipment is limited, the economics may not justify the application of insulation. Costs basis and frequency of maintenance and ultimate replacement of both blown and wrapped insulation should be identified.

IV. Background data and assumptions used
Most fired units in the Four Corners area are utilized during the time period from November through March to achieve their objective.

V. Any uncertainty associated with the option (Low, Medium, High) Low.
Differing opinion: High in terms of emission reductions.

VI. Level of agreement within the work group for this mitigation option TBD.

Mitigation Option: Portable Desiccant Dehydrators

I. Description of the mitigation option

Desiccant dehydrators utilize moisture-absorbing salts (e.g., calcium, potassium or lithium chlorides) to remove the water from natural gas.

Glycol dehydrators may be more suitable than desiccant systems in some field gas dehydration situations (e.g., when inlet gas has a high temperature and low pressure). But glycol dehydrators require regulator maintenance for optimal performance. During maintenance periods production wells are either shut-in or vented to the atmosphere (rather than running wet gas into the pipeline). Venting is especially popular for low-pressure wells, because it can be difficult to resume gas flow once they are shut in.

Portable desiccant dehydrators can be brought on-site during glycol dehydrator maintenance (or break-down) periods. This allows the gas to be processed and sent to the pipeline, rather than requiring the well to be shut-in, or the gas to be vented. These portable dehydrators can also be used to capture and dehydrate gas during "green completion" operations.

The benefits of utilizing portable desiccant dehydrators are: the ability to continue producing a well during glycol dehydrator maintenance; the elimination of methane, VOCs and HAPs that would otherwise be vented while glycol dehydrators are being serviced.

II. Description of how to implement

A. Mandatory or voluntary

Voluntary at this point in time. There are technologies that would result in much more significant air emissions reductions that should have higher regulatory priority.

Differing opinion: On March 20, 2007 at the NMOCD Greenhouse Gas meeting held in Santa Fe, NM, an operator stated during his presentation that based on their company's experience with salt dehydration in Wyoming, they are removing all salt dehydrators from service. Although the economics and technical feasibility initially looked very favorable, they have found salt slippage and other operational concerns very problematic with no technical solutions to date. Thus this method of dehydration is currently not as viable for their operations.

B. Indicate the most appropriate agency(ies) to implement

Environment/Health Departments, which have the responsibility for the regulation of air quality.

III. Feasibility of the option

A. Technical

A portable desiccant dehydrator requires a truck that has been modified to house the dehydrator; and ancillary equipment (e.g., piping) to re-route gas flow from the glycol to the desiccant dehydrator. See the discussion of technical feasibility in the desiccant dehydration option paper – the same comments and issues apply here.

B. Environmental

Desiccant dehydration systems work best under certain gas temperature and pressure conditions. Wastewater by product would need to handled, disposed of or re-injected. In the CBM areas of Colorado the gas is predominately methane and the gas is relatively dry gas and requires little dehydration. In this case VOC emissions are minimal. Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required. As a result of the type of production in this region it is likely that dehydration emissions are not significant and the use of such alternative technology may not be warranted.

C. Economic

Capital cost of a 10-inch portable desiccant dehydrator is estimated to be greater than \$4,000. Operating costs (e.g., labor, transportation, set-up and decommissioning) are on the order of \$5,000/yr.

Differing opinion: Cost is prohibitive for replacement of existing systems but applicable for new installations as determined on a case-by-case evaluation. Increased operational costs for the desiccant, storage, and handling/disposal of wastewater should be factored in to the economics.

One operator reports that portable desiccant dehydrators are economical when used on gas wells that produced more than 15.6 Mcf/day.

Obviously, a company would get the most economic benefit from owning this equipment if the equipment was kept in continual operation – i.e., moved from one site immediately to another.

IV. Background data and assumptions used
All information in this mitigation option comes from: U.S. EPA. *Portable Desiccant Dehydrators.* PRO Fact Sheet No. 207. Available at: http://www.epa.gov/gasstar/pdf/pro_pdfs_eng/portabledehy.pdf

V. Any uncertainty associated with the option TBD.
Differing opinion: MEDIUM-HIGH based above comments regarding generation of wastewater, disposal, and recent operational experiences in Wyoming.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None at this time.

Mitigation Option: Zero Emissions (a.k.a. Quantum Leap) Dehydrator

I. Description of the mitigation option

Conventional glycol dehydrators route natural gas through a contactor vessel containing glycol, which absorbs water (and VOCs, HAPs) from the gas. Typically, gas-driven pumps are then used to circulate glycol through a reboiler/stripper column, where it is regenerated, then sent back to the contactor vessel. Distillation and reboiling removes VOCs, HAPs and absorbed water from the glycol, and releases these compounds through the "still column" vent as vapor. Conventional glycol dehydrators vent directly to the atmosphere. Add-on technologies, such as thermal oxidizers, can reduce the amount of methane and VOCs that are vented, but result in increased NO_x, particulate matter and CO emissions.[1]

Natural gas dehydration is the third largest source of methane emissions and causes more than 80% of the natural gas industry's annual HAP and VOC emissions.[2] In the CBM areas of Colorado the gas is predominately methane and the gas is relatively dry gas and requires little dehydration. In this case VOC emissions are minimal. Conventional production in New Mexico also has very little moisture in the gas and little dehydration is required. As a result of the type of production in this region it is likely that dehydration emissions are not significant and the use of such alternative technology may not be warranted.

The zero emissions dehydrator combines several technologies that lower emissions. These technologies eliminate emissions from glycol circulation pumps, gas strippers and the majority of the still column effluent.

- Rather than being released as vapor, the water and hydrocarbons are collected from the glycol still column, and the condensable and non-condensable components are separated from each other. The two primary condensable products are wastewater, which can be disposed of with treatment; and hydrocarbon condensate, which can be sold. The non-condensable products (methane and ethane) are used as fuel for the glycol reboiler, instead of releasing them to the atmosphere.
- A water exhauster is used to produce high glycol concentrations without the use of a gas stripper.
- Methane emissions are further reduced by using electric instead of gas-driven glycol circulation pumps.

Benefits of this technology include:

- Elimination of methane emissions.[3]
- Elimination of virtually all VOCs (reduction from multiple tons per year to pounds per year.[4]
- Has a HAP destruction efficiency of greater than 99%.[5]
- Reduces emissions of particulate matter, sulfur dioxide, NO_x or CO emissions (these compounds are emitted when thermal oxidation, a competing method of reducing glycol dehydrator VOC emissions, is used).
- Eliminates the Kimray pump, which is typically used to circulate glycol. Kimray pumps require extra gas (which is eventually vented to the atmosphere) for pump power.[6]
  - Significantly reduces fuel requirements for glycol reboiler. Natural gas that was used for this purpose can now be sent to market.
  - Results in collection of condensate, which can be sold.

II. Description of how to implement

A. Mandatory or voluntary

The zero emissions dehydrator system offers incredible reductions in emissions. States that are experiencing air quality problems could make this a mandatory technology, and achieve large reductions in VOC, HAP and methane emissions.

Differing opinion: Previous statement requires supporting documentation and quantification of 'trade-off' pollutants.
B. Indicate the most appropriate agency(ies) to implement
Dehydration is not a down-hole issue, therefore, is not the sole purview of the oil and gas commissions. Furthermore, this option relates specifically to minimizing air emissions. Thus, the most appropriate agencies to implement this option would be the environment/health agencies in the different states.

III. Feasibility of the option
A. Technical
The operation of the glycol circulation pump requires electric utilities or an engine generator set. The use of electric pumps (rather than fossil fuel driven pumps) will minimize NO_x, CO, CO_2, SO_2 emissions at the wellhead, but will result in some emissions at electrical generation source (e.g., coal-fired power plant).

Zero emissions dehydrators can be newly installed, and existing dehydrators can be retrofitted by modifying the gas stream piping and using a 5 kW engine-generator for electricity needs.[7] This requires a fuel or power source, for which associated emissions need to be quantified.

B. Environmental
Environmental benefit for this mitigation option needs to be defined.

C. Economic[8]
Capital costs of a zero emissions dehydrator are similar to the costs of installing a conventional dehydrator equipped with a thermal oxidizer (>$10,000). Operating and Maintenance costs are greater than $1,000 per year, but lower than the maintenance costs for conventional glycol dehydrators.

If operators were to install zero emissions dehydrators, EPA estimates that the payback to occur in less than a year.
Differing opinion: This presumes the ability to recover the hydrocarbons for sales – which is not without significant challenges and technical difficulties.

IV. Background data and assumptions used

The calculations of methane, VOC and HAP emissions from the zero emissions dehydrator were based on a dehydrator that processed 28 MMcf/day.[9] Other assumptions are contained in the endnotes.

If we had emissions data for glycol dehydrators from the San Juan Basin, we could provide a more accurate (and basin-specific) comparison of methane, VOC and HAP emissions from conventional dehydrators versus emissions from zero emissions dehydrators.

V. Any uncertainty associated with the option TBD.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None at this time.

Notes:
1. Permit renewal application by Centerpoint Energy Gas Transmission Co. to Louisiana Department of Environmental Quality. AI# 26802. March, 2005. Available at: http://www.deq.louisiana.gov/apps/pubNotice/show.asp?qPostID=2335&SearchText=centerpoint&startDate=1/1/2005&endDate=7/6/2006&category=

The application includes estimated emissions scenarios for controlling glycol dehydrator still column vent emissions with or without thermal oxidation.

2. McKinnon, H.W. and Piccot, S.D. 2003. "Emissions control of criteria pollutants, hazardous pollutants, and greenhouse gases, Natural Gas Dehydration, Quantum Leap Dehydrator." Environmental Technology Verification Program, Joint Verification Statement. U.S. EPA and Southern Research Institute. Available at: http://www.epa.gov/etv/pdfs/vrvs/03_vs_quantum.pdf
3. *ibid.*
4. Rueter, C.O., Reif, D.L. and Myers, D.B. 1995. Glycol dehydrator BTEX and VOC emissions testing results at two units in Texas and Louisiana. U.S. EPA Air and Energy Engineering Research Laboratory. Project No. EPA/600/SR-95/046.

   A study of two glycol dehydrators, processing 3.6 and 4.9 million standard cubic feet of gas per day, were found to have VOC emissions of approximately 19 and 37 tons of VOC/year, respectively. Tests run on the Zero Emissions Dehydrator, processing 28 million standard cubic feet of gas per day, resulted in average emissions of 0.0003 lb/h (2.6 lbs/yr). This is a dramatically lower amount of VOC emissions than conventional glycol dehydrators.
5. McKinnon, H.W. and Piccot, S.D. 2003. (See Note 2)
6. Fernandez, R., Petrusak, R., Robins, D. and Zavodil, D. June, 2005. "Cost-effective methane emissions reductions for small and midsize natural gas producers," Journal of Petroleum Technology. Available at: http://www.icfi.com/Markets/Environment/doc_files/methane-emissions.pdf
7. U.S. EPA. "Zero emissions dehydrators," PRO Fact Sheet No. 206. Available at: http://www.epa.gov/gasstar/pdf/pro_pdfs_eng/zeroemissionsdehy.pdf
8. All of the economic information comes from: U.S. EPA. (see Note 7)
9. McKinnon, H.W. and Piccot, S.D. 2003. (See Note 2)

Mitigation Option: Venting versus Flaring of Natural Gas during Well Completions

I. Description of the mitigation option

Both venting and flaring of natural gas result in the release of greenhouse gases, hazardous air pollutants (HAPs) and others.

The venting of natural gas primarily releases methane, a greenhouse gas. Depending on the composition of the gas, venting will release other hydrocarbons such as ethane, propane, butane, pentane and hexane. In some locations, natural gas contains the EPA-designated HAPs benzene, toluene, ethyl benzene and xylenes (BTEX). Both hexane (also a HAP) and the BTEX compounds are present in San Juan Basin natural gas, typically accounting for 0.3 - 0.6 % of the natural gas composition.[1]
Differing opinion: This is only true for the conventional production. Coal bed methane does not contain appreciable amounts of VOCs or HAPs. Depending on the formation, natural gas may also contain nitrogen, carbon dioxide or sulfur compounds, such as hydrogen sulfide (H_2S), which is a highly toxic gas. In the New Mexico portion of the San Juan Basin, there are at least 375 gas wells, from at least five different producing formations, that contain hydrogen sulfide.[2]

Flaring is used as a means of converting natural gas constituents into less hazardous and atmospherically reactive compounds. The main purpose for flaring is for process safety reasons. Flaring is required when completing a well for two reasons: (1) the initial gas and liquids produced by most wells does not meet the gas gatherer's (pipeline's) quality requirements, and (2) the flare is the primary safety device in the event of an overpressure or equipment failure. The objective for both industry and the public is to minimize flaring where possible for both environmental and economic reasons. The assumption is that combustion processes associated with flares efficiently converts hydrocarbons and sulfur compounds to relatively innocuous gases such as CO_2, SO_2, and H_2O.

While industrial flares associated with processes such as refineries have the potential to be highly efficient (e.g., 98-99%), the few studies that have been conducted on oil and gas "field flares" have found much lower efficiencies (62-84%).[3] Fields flares without combustion enhancements (e.g., knockout drums to collect liquids prior to entering the flare; flame retention devices; pilots) have a much lower efficiency compared to properly designed and operated industrial flares.[4] Other factors, such as improper liquids removal,[5] low heating value of the fuel,[6] flow rate of gas,[7] and high wind speeds,[8] also decrease the combustion efficiency of flares.
Differing opinion: The one study cited is the only flare study that found low destruction efficiencies when burning production type gas streams. A number of other studies have confirmed destruction efficiencies >98% - which is the EPA guidance. A cooperative study, known as the international flare consortium study, is underway now and is testing destruction efficiencies across a wide range of gas types, flare types, and conditions.

There is a dearth of information on combustion efficiencies for flares used during well completion events, but given the fact that these flares are more rudimentary than industrial or even solution gas flares, it is highly possible that they have even lower combustion efficiencies.
Differing opinion: There are a number of very well done flare studies published.

When flares burn inefficiently, a host of hydrocarbon by-products that include highly reactive VOCs and polycyclic aromatic hydrocarbons, may be formed.[9] Leahey et al. (2001) found more than 60 hydrocarbon by-products, including known carcinogens such as benzene, anthracene and benzo(a)pyrene, downwind of a natural gas flare estimated to be operating at 65% combustion efficiency.[10] The inefficient burning of hydrocarbons also produces soot (particulate matter).[11] Additionally, nitrogen oxides are formed during the combustion process, even if the flare gas does not contain nitrogen.[12]

Differing opinion: The one study cited is the only flare study that found low destruction efficiencies when burning production type gas streams. A number of other studies have confirmed destruction efficiencies >98% - which is the EPA guidance. A cooperative study, known as the international flare consortium study, is underway now and is testing destruction efficiencies across a wide range of gas types, flare types, and conditions.

See the Endnotes for a table that summarizes the potential health and environmental effects related to compounds released during flaring and venting.[13]

Differing opinion: Not having access to the original table(s), it appears that errors may have occurred when it was adapted given the unwarranted combination of gas constituents and combustion products in one table and some obvious flaws (i.e., VOCs, SO2 and NOx contributing to particulate pollution but not aggravating respiratory conditions).

Flares operated during well completion activities handle enormous volumes of gas, which is either vented or flared over a short period of time. The amounts of HAPs and VOCs produced during a typical well completion in Wyoming have been calculated. It has been estimated that a single well completion event, which lasts an average of 10 days, releases:

- 115 tons of VOCs, and 4 tons of HAPs (assumption: 100% venting); or
- *86* tons VOCs, and *3* ton HAPs (assumption: half of the gas is flared per completion, and the flare operates at 50% efficiency).[14]

Differing opinion: Many completions in Wyoming – particularly those with gas flow rates in the 4 MMSCF/day range suggested above – are completed using flareless completion techniques which significantly reduces volume flared (75 to 90% reduction). However, use of these techniques is limited to those areas where the reservoir pressure is high enough to clean up the well and get the gas into the pipeline.

While it is clear that flaring reduces the volume (mass) of VOCs and HAPs, questions remain, such as: what are the particular VOC and HAP compounds released during both venting and flaring; what are the concentrations of these compounds in ambient air; [15] and can well completion flares somehow be designed (e.g., better liquid removal, lower gas flow rates going to the flare) to more effectively destroy hazardous compounds.

For a true assessment of the relative benefits of flaring vs. venting (especially with respect to human health), there is a need for a better assessment of venting/flaring emissions from well completions in the San Juan Basin. This assessment should determine both volumes of emissions, and provide a characterization of VOCs, HAPs and other compounds emitted (volumes and species) during well completion venting and flaring.

II. Description of how to implement

Using methods similar to those used in Wyoming, calculations could be performed to estimate the amount of VOCs and HAPs released from flaring and venting during well completion events in the San Juan Basin. Information requirements include:

- volume of gas released (vented or flared) per well completion
- VOC and HAP weight % of the natural gas
- estimates of combustion efficiency of flares
- estimates of how often flares are extinguished (resulting in venting of gas)

Monitoring downwind of sites that are flaring and/or venting is needed, to better characterize concentrations and species of VOCs and HAPs, as well as other flaring by-products.

A. Mandatory or voluntary
Initially, it could be a voluntary initiative, but if that does not produce data or results there may need to be mandatory reporting and monitoring requirements.

B. Indicate the most appropriate agency(ies) to implement
State oil and gas commissions could require the reporting of well completion emissions volumes; and environment/health departments would be the appropriate agencies to require monitoring of venting and flaring emissions.

III. Feasibility of the option
A. Technical
Emissions volumes from well completions have been determined for Wyoming, so presumably it is technically feasible to determine volumes for the San Juan Basin. If the data do not exist, perhaps the monitoring work group could work with industry to calculate or develop estimates of these volumes specific to the San Juan Basin.

Researches in Alberta have been able to determine combustion by-products using on-site analytical equipment or through absorbent samplers for confirmatory analyses by combined gas chromatography/mass spectrometry. Flare combustion efficiency were then calculated using a carbon mass balance of combustion products identified in the emissions. See Strosher (1996), Endnote 4.

B. Environmental
None.

C. Economic
Emissions volumes from well completions: low cost.
The identification of compounds emitted during venting and combustion: unknown.

IV. Background data and assumptions used See Endnotes Section.

V. Any uncertainty associated with the option
High uncertainty: depends on willingness of industry and regulators to undertake the necessary data collection.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None.

Notes:
1. Proportions calculated based on data from: Mansell, G.E. and Dinh, T. (ENVIRON International). September 2003. Emission Inventory Report - Air Quality Modeling Analysis For The Denver Early Action Ozone Compact: Development of the 2002 Base Case Modeling Inventory. p. 3-5.
http://apcd.state.co.us/documents/eac/2002%20Modeling%20EI.pdf

Table 3-5. Average gas profiles (% composition) by formation for the San Juan Basin

	Mesa Verde	Dakota	Pictures Cliffs	Gallup	
Nitrogen	0.212	1.603	0	0.965	
Carbon Dioxide	1.388	1.034	1.403	0.639	
Methane	84.372	74.979	87.736	76.944	
Ethane	8.221	12.163	6.373	10.823	
Propane	3.19	6.488	2.651	6.552	
Butanes	1.432	2,532	1,148	2.551	
Pentanes	0.727	0.765	0.418	0.948	
Hexanes	0.459	0.437	0.270	0.578	
Benzene	0.0145	0.016	0.003		
Toluene	0.00706	0.003	0.0014		
Ethyl Benzene	0.00037	0.0001	0.0002		
Xylene	0.002	0.0006	0.001		
Calculated VOC and HAP content (not in original chart)					Average for all formations
HAPS (BTEX + hexane)	0.483	0.457	0.276	0.578	0.4483
VOCs (C1-C4)	97.94	96.93	98.33	97.82	97.753

2. Hewitt, J. (Bureau of Land Management). 2005. "H2S Occurrences San Juan Basin," a presentation at Hydrogen Sulfide: Issues and Answers Workshop. http://octane.nmt.edu/sw-pttc/proceedings/H2S_05/BLM_H2S_SanJuanBasin.pdf

3. Strosher, M. 1996. Investigations of Flare Gas Emissions in Alberta. Alberta Research Council, November 1996.

Strosher (1996) found flaring efficiencies of 62-71% and 82-84% for sweet and sour gas flares, respectively. The sweet gas had a higher liquid hydrocarbon content than the sour gas being flared. Leahy et al. (2001, citation in Endnote 9) observed flare efficiencies of 68 ±7 % at sweet and sour gas flares in Alberta.

4. Seebold, J., Davis, B., Gogolek, P., Kostiuk, L., Pohl, J., Schwartz, B., Soelberg, N., Strosher, M., and Walsh, P. 2003. "Reaction Efficiency of Industrial Flares: the perspective of the past." International Flare Consortium, Combustion Canada '03 Paper. http://www.nrcan.gc.ca/es/etb/cetc/ifc/id4_e.html

5. Russell, J. and Pollack, A. (ENVIRON International). 2005. Final Project Report: Oil And Gas Emission Inventories For The Western States. Report prepared for the Western Governors' Association. Appendix A, Wyoming Emission Factor Documentation. p. A-2. http://www.wrapair.org/forums/ssjf/documents/eictts/OilGas/WRAP_Oil&Gas_Final_Report.122805.pdf

When liquid content is too high, flares don't or won't ignite.

6. Kostiuk, L.W., M.R. Johnson & R.A. Prybysh. 2000 "Recent Research on the Emission from Continuous Flares," Paper presented at CPANS/PNWIS–A&WMA Conference (Banff, Alberta, April 10-12). Cited in: Seebold et al. (2003).

7. Strosher, M. 1996. Investigations of Flare Gas Emissions in Alberta. Alberta Research Council, November 1996. p. 85.

Combustion efficiencies decreased from 70.6% (flow rate of 1 m3/min) to 67.2 % (flow rate of 5-6 m3/min) for sweet gas being flared at an oil tank battery in Alberta.

Increasing the flow increased the volatile hydrocarbons by about 33%, and the non-volatiles by three times the concentrations found in the lower volume flow.

8. Leahey, Douglas M., Preston, Katherine and Strosher, Mel. 2001. Theoretical and Observational Assessments of Flare Efficiencies," Journal of the Air & Waste Management Association. Volume 51. p. 1615

"It has been shown, as well, that flaring can be efficient only at low wind speeds because the size of the flare flame, which is an indicator of flame efficiency, decreases with increasing wind speed. Therefore, the flaring process could routinely result, during periods of moderate to high wind speeds, in appreciable quantities of products of incomplete combustion such as anthracene and benzo(a)pyrene, which can have adverse implications with respect to air quality."

9. Seebold, J., Gogolek, P., Pohl, J., and Schwartz, R. 2004. "Practical implications of prior research on today's outstanding flare emissions questions and a research program to answer them," Paper presented at the AFRC-JFRC 20004 Joint International Combustion Symposium, Environmental Control of Combustion Processes: Innovative Technology for the 21st Century. (Oct. 10-13, 2004; Maui, Hawaii). http://www.nrcan.gc.ca/es/etb/cetc/ifc/id12_e.html

For example, during the 1990s, research conducted as part of the Petroleum Environmental Research Forum's project 92-19 "The Origin and Fate of Toxic Combustion By-Products in Refinery Heaters" showed that even when burning laboratory grade methane "pure as the drifted snow" traces of higher molecular weight compounds not originally present in the fuel are found in the flue gas (e.g., ethylene, propylene, butadiene, formaldehyde, benzene, benzo(a)pyrene and other hydrocarbons in the gas phase up through coronene).

Seebold, et al. also report that, "the external combustion of hydrocarbon gas mixtures by any means, including flaring, literally manufactures and subsequently emits to the atmosphere traces of all possible molecular combinations of the elemental constituents present either in the fuel or in the air including the ozone precursor highly reactive volatile organic compounds (HRVOCs) and the carcinogenic hazardous air pollutants (HAPs).

10. Leahey, Douglas M., Preston, Katherine and Strosher, Mel. 2001. Theoretical and Observational Assessments of Flare Efficiencies," Journal of the Air & Waste Management Association. Volume 51. p.1614. http://www.awma.org/journal/pdfs/2001/12/Leahey.pdf

Speciated data for combustion products observed downwind of the sweet gas flare using solvent extraction methods.

Product	Volume (mg/m3)	Product	Volume (mg/m3)
Nonane	0.41	9h-fluorene, 3-methyl-	3.05
Benzaldehyde (acn)(dot)	0.53	Phenanthrene	10.01
Benzene, 1-ethyl-2-methyl-	0.13	Benzo(c)cinnoline	2.06
1h-indene, 2,3-dihydro-	0.34	Anthracene	42.11
Decane	1.72	1h-indene, 1-(phenylmethylene)-	1.94
Benzene, 1-ethynyl-4-methyl-	9.83	9h-fluorene, 9-ethylidene-	0.89
Benzene, 1,3-diethenyl-	1.27	1h-phenalen-1-one	1.86
1h-indene, 1-methylene-	0.28	4h-cyclopenta[def]phenanthrene	3.50
Azulene	21.20	Naphthalene, 2-phenyl-	1.98
Benzene, (1-methyl-2-cyclopropen-1-yl)-	11.47	Naphthalene, 1-phenyl-	1.82
1h-indene, 1-methyl-	1.66	9,10-anthracenedione	0.94
Naphthalene (can)(dot)	99.39	5h-dibenzo[a,d]cycloheptene, 5-methylene-	0.75
Benzaldehyde, o-methyloxime	0.27	Naphthalene, 1,8-di-1-propynyl-	1.14
1-h-inden-1-one, 2,3-dihydro-	0.74	Fluoranthene 51.35 Benzene, 1,1'-(1,3-butadiyne-1,4-diyl)bis-	2.07

Naphthalene, 2-methyl-	9.25	Pyrene	32.37
Naphthalene, 1-methyl-	6.18	11h-benzo[a]fluorene	2.25
1h-indene, 1-ethylidene-	1.22	Pyrene, 4-methyl-	9.13
1,1'-biphenyl	58.70	Pyrene, 1-methyl-	8.38
Naphthalene, 2-ethyl-	1.87	Benzo[ghi]fluoranthene	10.16
Biphenylene	42.81	Cyclopenta[cd]pyrene	29.77
Naphthalene, 2-ethenyl-	7.32	Benz[a]anthracene	17.33
Acenaphthylene	7.15	Chrysene	2.12
Acenaphthene	2.93	Benzene, 1,2-diphenoxy-	1.94
Dibenzofuran	0.88	Methanone, (6-methyl-1,3-benzodioxol-5-yl)phenyl-	0.95
1,1'-biphenyl, 3-methyl-	0.31	Benzo[e]pyrene	0.71
1h-phenalene	21.01	Benzo[a]pyrene	1.03
9h-fluorene	41.09	Perylene	0.62
9h-fluorene, 9-methyl-	1.07	Indeno[1,2,3-cd]pyrene	0.15
Benzaldehyde, 4,6-dihydroxy-2,3-dimethyl	1.16	Benzo[ghi]perylene	0.26
9h-fluorene, 9-methylene-	1.07	Dibenzo[def,mno]chrysene	0.15
		Coronene	0.08

11. U.S. Environmental Protection Agency. 2000. Office of Air Quality Planning and Standards. “Industrial Flares,” AP-42 Fifth Edition. Vol. 1: Stationary Point and Area Sources. p. 13.5-3.
Tendency to smoke or make soot is influenced by fuel characteristics and by amount and distribution of oxygen in the combustion zone. All hydrocarbons above methane tend to soot. Soot from industrial flares is eliminated by adding steam or air.
Soot emissions factors developed by EPA for industrial flares are: non-smoking flares, 0 micrograms per liter (µg/L); lightly smoking flares, 40 µg/L; average smoking flares, 177 µg/L; and heavily smoking flares, 274 µg/L.
12. K.D. Siegel. 1980l. Degree of Conversion of Flare Gas in Refinery High Flares. Dissertation. University of Karlsruhe, Germany. Cited in: USEPA Office of Air Quality Planning and Standards. 2000. “Industrial Flares,”AP-42 Fifth Edition. Volume 1: Stationary Point and Area Sources. p.13.5-5.
Even waste gas that does not contain nitrogen compounds form NO. It is formed either by fixation of atmospheric nitrogen with oxygen, or by the reaction between hydrocarbon radicals and atmospheric N by way of intermediate states, HCN, CN and OCN.
13. Health and Environmental Effects of Chemicals Released During Venting and Flaring.

	VOCs	SO2	NOx	CO	PAHs	H2S	HAPs	SMOKE/ SOOT
Contributes to particulate pollution that can cause respiratory illness, aggravation of heart conditions and asthma, permanent lung damage and premature death.								
	FLARING	FLARING	FLARING					FLARING
Aggravates respiratory conditions						VENTING		
								FLARING

	VOCs	SO2	NOx	CO	PAHs	H2S	HAPs	SMOKE/SOOT
Can cause health problems such as cancer	VENTING						VENTING	
	FLARING				FLARING		FLARING	
Can cause reproductive, neurological, developmental, respiratory, immune system, and other health problems.							VENTING	
							FLARING	
Reacts with other chemicals leading to ground-level ozone and smog, which can trigger respiratory problems	VENTING							
	FLARING		FLARING					
Reacts with common organic chemicals forming toxins that may cause bio-mutations								
			FLARING					
Affects cardiovascular system and can cause problems within the central nervous system						VENTING		
Causes haze that can migrate to sensitive areas such as National Parks	VENTING							
	FLARING	FLARING	FLARING	FLARING				FLARING
Contributes to global warming	VENTING							

Adapted from: EPA Office of Inspector General. 2004. EPA Needs to Improve Tracking of National Petroleum Refinery Program Progress and Impacts. Appendix D.

14. Russell, J. and Pollack, A. (ENVIRON International). 2005. Final Project Report: Oil And Gas Emission Inventories For The Western States. Report prepared for the Western Governors' Association. Appendix A, Wyoming Emission Factor Documentation. p. A-2.
http://www.wrapair.org/forums/ssjf/documents/eictts/OilGas/WRAP_Oil&Gas_Final_Report.122805.pdf

15. Strosher, M. 1996. Investigations of Flare Gas Emissions in Alberta. Alberta Research Council, November 1996. p. 28.
Strosher measured concentrations of hydrocarbon compounds emitted from sweet and sour solution gas flares in Alberta, and then predicted ground-level concentrations of HAPs at various locations around the well location. Predicted values of some polycyclic aromatic hydrocarbons in the vicinity of sweet and sour gas flares were comparable to concentrations found in large industrial cities, while predicted values of hazardous VOCs released during flaring were below ambient air quality standards.

Mitigation Option: Co-location/Centralization for New Sources

I. Description of the mitigation option

This mitigation option would involve co-locating and/or centralizing new oil/gas field facilities, including roads, well pads, utilities, pipelines, compressors, power sources and fluid storage tanks, wherever possible, to reduce surface impacts, fugitive dust, engine emissions and gas field traffic.

In general, co-location and/or centralization of new facilities would result in overall reductions in surface disturbance, vehicular traffic, and number of facilities. Potential benefits from this strategy include fugitive dust reduction (due to decreased traffic and less overall new surface disturbance), vehicle emission reductions, reduced road maintenance, safer roads as a result of decreased traffic, and oil/gas field engine emission reductions. The potential for reduced engine emissions is due in part to lowering cumulative horsepower requirements by using larger, more efficient engines, and in part to groups of smaller engines with relatively high emission rates per hp/hr being replaced by fewer, larger engines with relatively low emission rates per hp/hr. Implementation costs for this mitigation option would fall exclusively on the energy companies, but such costs could be partially offset by the economic benefits of having fewer facilities to construct, maintain and ultimately reclaim.

Tradeoffs include increased impacts at co-located/centralized sites. Co-locating well bores on a single pad results in larger pad sizes that may not fit well with pre-existing conditions. Centralizing facilities would increase vehicle emissions locally and potentially produce local air quality, noise, visual and traffic safety issues. Additionally, aggregating produced water in one location increases the potential for a catastrophic release.

II. Description of how to implement

A. This mitigation option should be implemented on a voluntary basis, with the approach emphasized by the appropriate regulatory agency during the planning and permitting processes for oil/gas field facilities and utility corridors (pipelines, power lines, etc.). Consideration should be given to economic and environmental impacts, as well as current and future land management activities. Ideally, oil/gas field operators and regulatory agencies would coordinate on a regular basis to identify development plans that minimize new construction and maximize efficiencies. Cooperation between operators in the same development area would make this option even more effective, but multiple economic and regulatory constraints exist that make such coordination difficult.

B. State and Federal lands and minerals management agencies would be able to emphasize this approach at various stages of the planning and permitting process. In addition, State and Federal air regulatory agencies could emphasize this approach if multiple air quality permit applications are submitted concurrently for the same general area.

III. Feasibility of the option

A. Technical: The technology exists today to implement this mitigation option. This option is best suited for areas of known or high potential for economic oil/gas field production. This option can be implemented most effectively when planning for oil/gas field- or lease-wide development activities, such as in-fill drilling and plans of development for multiple wells.

B. Environmental: Co-location and/or centralization of new facilities would generally have numerous environmental benefits.

C. Economic: Economic feasibility of this option will vary on a project-level basis. Higher initial costs may be offset by overall cost reductions due to fewer facilities to construct, operate and reclaim. Additional cost savings may result because co-located/centralized facilities can be more efficient than dispersed facilities.

IV. Background data and assumptions used
This option is best suited for areas with existing or high potential for economic gas/oil field production.

V. Any uncertainty associated with the option
Low. While implementation of this option may cause greater noise, emission, and visual impacts at fewer, co-located/centralized locations, the overall effect would be a reduction in oil/gas field environmental impacts.

VI. Level of agreement within the work group for this mitigation option Unknown at this time

VII. Cross-over issues to the other source groups
Road-related impacts are an element of this mitigation option being looked at by the Other Sources Workgroup. Two other mitigation strategies (Optimization/Centralization and Reduced Truck Traffic by Centralizing Produced Water Storage Facilities) look at the compression and produced water facets of this mitigation option in greater detail and are presented in the Oil and Gas section of this Task Force Report. Assistance from the Cumulative Effects work group to quantify potential dust, vehicle traffic and overall emission reductions resulting from co-location and/or centralization would be helpful.

VIII. References

http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas/best_management_practices.html

http://www.westgov.org/wga/initiatives/coalbed/

http://bogc.dnrc.state.mt.us/website/mtcbm/webmapper_cbm_info_res.htm

Mitigation Option: Control Glycol Pump Rates

<u>I. Description of the mitigation option</u>
Most dehydration systems use triethylene glycol (TEG) as the absorbent fluid to remove water from natural gas. As TEG absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). As TEG is regenerated through heating in a reboiler, absorbed methane, VOCs, and HAPs are vented to the atmosphere with the water, wasting gas and money. The amount of methane absorbed, and used as assist gas for Kimray type pumps, and vented is directly of the TEG Dehydrator, but continue to circulate TEG at rates two or three times higher than necessary, resulting in little improvement in gas moisture quality but much higher methane emissions and fuel use. Reducing TEG circulation rates reduce methane emissions at negligible cost.

Economic burdens are minimal since this practice simply requires the pump rate to be manually adjusted.

<u>II. Description of how to implement</u>
<u>A. Mandatory or voluntary:</u> The implementation of lower TEG circulation rates should be "voluntary" since the measure would enhance recovery of natural gas and reduce emissions. Companies should be receptive to voluntarily implement this measure.
<u>B. Indicate the most appropriate agency(ies) to implement</u>**:** The state Air Quality Divisions should communicate this information.

<u>III. Feasibility of the option</u>
<u>A. Technical:</u> Controlling TEG circulation rates are technically feasible since it can be achieved by manually setting the pump rate.
<u>B. Environmental:</u> The environmental benefits of reduced VOC pollution are well documented. The reduction of methane, a greenhouse gas, can also be documented. Quantification of emission reductions can be achieved through the use of the GLYCALC model.
Due to the low field pressures in the San Juan basin area, most field dehydrators have been removed and dehydration is done at central facilities rather than dispersed locations. Due to this, this option will have very limited applicability and emission reductions associated with it.
<u>C. Economic:</u> The benefits can be quantified by the amount of methane and VOC that is not emitted to the atmosphere and rather sold as product.

<u>IV. Background data and assumptions used</u>
A. Gas production fields experience declining production as pressure is drawn-off the reservoir. Wellhead glycol dehydrators and their TEG circulation rates are designed for the initial, highest production rate, and therefore, become over-sized as the well matures. It is common that the TEG circulation rate is much higher than necessary to meet the sales gas specification for moisture content.
B. The methane emissions from a glycol dehydrator are directly proportional to the amount of TEG circulated through the system. The higher the circulation rate, the more methane, is vented from the regenerator. Over-circulation results in more methane emissions without significant and necessary reduction in gas moisture content.
C. Operators can reduce the TEG circulation rate and subsequently reduce the methane emissions rate, without affecting dehydration performance or adding any additional cost.

<u>V. Any uncertainty associated with the option</u> Low.

<u>VI. Level of agreement within the work group for this mitigation option</u>
Although a general discussion of this option has not occurred between the working group members, it is doubtful a disagreement about controlling TEG circulation rates would occur.

Source of Information: **"**Optimize Glycol Circulation and Install of Flash Tank Separators in Dehydrators", U.S. EPA Natural Gas Star Program.

Mitigation Option: Combustors for Still Vents

I. Description of the mitigation option

Most dehydration systems use triethylene glycol (TEG) as the absorbent fluid to remove water from natural gas. As TEG absorbs water, it also absorbs methane, other volatile organic compounds (VOCs), and hazardous air pollutants (HAPs). The TEG is then distilled to strip water and consequently VOC from the TEG. Vapors and/or liquids in the still vent are typically greater than 90% volume water, with the balance being hydrocarbons along with small quantities of carbon dioxide and nitrogen. The still vent column is typically released to the atmosphere that includes emissions of hydrocarbons. It is important to note that gas composition is an important consideration in determining the need to install flares. Some natural gas, such as coalbed methane gas contains little, if any VOC component, and would not result in VOC emissions.

In order to reduce these emissions, combustion devices can be installed to combust hydrocarbon emissions, including VOCs, instead of venting them to the atmosphere. The combustion technology typically consists of an enclosed "flare/burner." It does require a condenser and separator upstream of the combustion device to avoid liquid hydrocarbons routed to the combustion device.

II. Description of how to implement

A. Mandatory or voluntary: The requirement for control of emissions from glycol dehydrators is included in the EPA's area source *Onshore Natural Gas Processing* MACT rules that have been proposed/promulgated. After careful analysis, EPA set emission and throughput based criteria to trigger these control requirements. Any control at lower emission or throughput rates should be voluntary.
B. Indicate the most appropriate agency(ies) to implement**:** The state Air Quality Divisions should develop the regulatory program to administer this program.

III. Feasibility of the option

A. Technical: Installing condensers and combustion devices to control emissions from dehydrator still vents is technically feasible since it is already being applied in various locations where controls of these emissions have been mandated.
B. Environmental: The environmental benefits of reduced VOC emissions are well documented. The reduction of methane, a greenhouse gas, can also be documented. Actual benefits are dependent on the amount and composition of the gas being dehydrated and are highly variable. Little benefit is expected for the San Juan basin due to the lack of field dehydration.
C. Economic: Costs are for a typical condenser and smokeless combustion chamber large enough to service a dehydrator in Wyoming are about $35,000 installed. There are no revenues from the gas as it is destroyed through combustion, and there is a fuel cost of about $1,800 per year for each pilot (at $3 per Mcf of gas).

IV. Background data and assumptions used Wyoming oil and gas presumptive BACT guidance.

V. Any uncertainty associated with the option Low where applicable.

VI. Level of agreement within the work group for this mitigation option

Although a general discussion of this option has not occurred between the working group members, it is unknown about the degree of acceptance regarding the use of combustors for still vents.

Source of Information: "Install Flares", PRO Fact Sheet No. 905, U.S. EPA Natural Gas Star Program. Gas Research Institute, Control Device Monitoring of Glycol Dehydrators; Condenser Efficiency Measurements and Modeling, 1997.

EXPLORATION & PRODUCTION: WELLS

Mitigation Option: Installation and/or Optimization of a Plunger Lift System

I. Description of the mitigation option

Overview

In mature gas wells, the accumulation of fluids in the well-bore can impede and sometimes halt gas production. Fluids are removed and gas flow maintained by removing accumulated fluids through the use of artificial lift (such as a beam pump) or enhanced fluid lift treatments or techniques, such as plunger lifts, velocity strings, swabbing, soap injection, or venting the well to atmospheric pressure (referred to as "blowing down" the well). Fluid removal operations, particularly well blow-downs, may result in substantial methane and associated VOC emissions to the atmosphere.

Installing a plunger lift system can be a cost-effective alternative for removing liquids on wells where the well-bore configuration, pressure profiles, and production characteristics enable its application. Plunger lift systems have the additional benefit of potentially increasing production, as well as significantly reducing methane and associated VOC emissions associated with blow-down operations. A plunger lift uses gas pressure buildup in a well to lift a column of accumulated fluid out of the well. The plunger lift system helps to maintain gas production and may reduce the need for other remedial operations.

Air Quality and Environmental Benefits

The installation of a plunger lift system serves as an interim well-bore deliquification methodology for the period between natural flowing lift and full artificial lift and can yield environmental and production benefits while reducing well blow-downs and their associated emissions. The extent and nature of these benefits depend on the individual well characteristics and the method of plunger lift control and operation.

New automation systems and control capabilities can improve plunger lift system optimization, monitoring, and control. For example, technologies such as programmable logic controllers and remote transmitter units can allow operators to control plunger lift systems thorough control algorithms or remotely, without regular field visits. These systems can offer enhanced plunger lift operation and effectiveness versus older plunger control systems.

By reducing the need for well-bore blow-down, plunger lift systems can lower emissions. Reducing repetitive remedial treatments and well work-over may also reduce methane and associated emissions. Natural Gas STAR partners have reported annual gas savings averaging 600 Mcf per well by avoiding blow-down and an average of 30 Mcf per year by eliminating or reducing well work-overs.

Economics

Lower capital and operational cost versus installing full artificial lift equipment (such as a beam pump). The costs of installing and maintaining a plunger lift are generally lower than the cost to install and maintain artificial lift equipment.

Lower well maintenance and fewer remedial treatments. Overall well maintenance costs are reduced because periodic remedial treatments such as swabbing or well blow-downs are reduced or no longer needed with plunger lift systems.

More effective well-bore deliquification and continuous production may improve gas production rates and increase efficiency. With proper optimization and control, plunger lift systems can also conserve the well's lifting energy and increase gas production. Regular fluid removal allows the well to produce gas continuously and helps prevent fluid loading that periodically halts gas production or "kills" the well. Often, the continuous removal of fluids results in daily gas production rates that are higher than the production rates prior to the plunger lift installation.

Reduced paraffin and scale buildup. In wells where paraffin or scale buildup is a problem, the mechanical action of the plunger running up and down the tubing may prevent particulate buildup inside the tubing. Thus, the need for chemical or swabbing treatments may be reduced or eliminated. Many different types of plungers are manufactured with "wobble-washers" to improve their "scraping" performance.

Other economic benefits. In calculating the economic benefits of plunger lifts, the savings from avoided emissions and enhanced production are only two factors to consider in the analysis. Additional savings may result from lower operational and well work costs.

Tradeoffs

Plunger lift systems do fail and can require additional maintenance versus blowing wells down. If return velocity is not controlled they may also "launch" through the plunger receiver and cause wellhead failure. Also, dependent on the control systems, they may require regular operator intervention.

Burdens

Installation of plunger lift systems can involve substantial costs particularly if changes to the well-bore tubulars are required. If adequate control systems and a means to power them are not available on a particular well, their installation will require additional expenditures.

II. Description of how to implement

A. Mandatory or voluntary: This option should be voluntary given the restrictions on applicability posed by well-bore configuration, pressure and build-up profile, and production characteristics. Each well must be evaluated for feasibility of plunger lift systems. A large number of wells in the Four Corners area already have artificial lift systems or other enhanced deliquification techniques already installed. Requiring all wells in the basin to replace other means of enhanced or artificial lift would be logistically and operationally unreasonable. A large percentage of the producing wells in the 4-corners area are already equipped with plunger lift systems. Most operators have an ongoing well evaluation program to determine the appropriate deliquification technology to apply to any particular well.

B. Indicate the most appropriate agency(ies) to implement**:** Non-applicable – voluntary implementation. However, workshops on plunger lift applicability, control, and operation may enhance implementation.

III. Feasibility of the option

A. Technical: The technical considerations necessary for plunger lift systems are well known and plunger lift systems are feasible where the well characteristics enable application. For very low pressure/flow environments, such as portions of the San Juan Basin, operation of plunger lifts may require periodic venting (blow-down) of well-bores to the atmosphere to generate enough differential energy to lift the plunger and associated fluids. Advanced control systems can significantly reduce the need for this type of blow-down but require robust automation capabilities.

B. Environmental: There are no known environmental issues with plunger lift implementation and they typically reduce emissions.

C. Economic: the economics of applying plunger lift technology to a particular well must be evaluated on a well-by-well basis. For wells where they are applicable, plunger lift systems are generally economic.

IV. Background data and assumptions used N/A

V. Any uncertainty associated with the option

Assuming a well-by-well evaluation of applicability the uncertainty associated with plunger lift implementation should be low. Due to the large number of wells already equipped with plunger lift or other enhanced or artificial lift systems the scope of available implementation may be limited.

VI. Level of agreement within the work group for this mitigation option

Still being evaluated, but based upon information to date it should be high.

Mitigation Option: Implementation of Reduced Emission Completions (Green Completions)

I. Description of the mitigation option

The "green completions" control method reduces methane losses during gas well completions. During well completions it is necessary to clean out the well bore and the surrounding formation perforations. This is done both after new well completions and after well workovers. Operators produce the well to an open pit or tanks to collect sand, cuttings and reservoir fluids for disposal. Normal practice during this process is to vent or flare the natural gas produced. Venting may lead to dangerous gas buildup, so flaring is preferred where there is no fire hazard or nuisance issue (concerns about smoke, light, noise, etc.). Green completions recover the natural gas and condensate produced during well completions or workovers. This is accomplished using portable equipment to process the gas and condensate so it is suitable for sale. The additional equipment may include more tanks, special gas-liquid-sand separator traps, and portable gas dehydration. The recovered gas is directed through permanent dehydrators and meters to sales lines, reducing venting and flaring. "Green completion" techniques are only applicable where the reservoir pressure and flow is sufficient to clean-up a well bore after completion and still have sufficient pressure to enter the collection system/pipeline. With the depleted status of the conventional San Juan basin reservoirs and the characteristics of coal bed methane reservoirs; this is not an available option for the SJ basin area.

II. Description of how to implement

A. Mandatory or voluntary

This process can be mandatory or voluntary.

B. Indicate the most appropriate agency(ies) to implement

For the 4 Corners area, State regulatory agencies could require green completions through regulation or policy. For example, in the Pinedale, WY area the State of Wyoming, BLM, and operators have agreed to minimize flaring operations through use of green completions. FLMs could require this process through stipulations or conditions of approval in leases and applications for permits to drill.

III. Feasibility of the option

A. Technical

The green completion process can apply to the drilling of all natural gas wells, however, a sales line connection and sales agreements need to be arranged before the well drilling is completed. There are operational, access and other considerations that make this a case determination.

Differing opinion: This technique is not feasible in the SJ basin – see above.

The green completion process has been reviewed by EPA and is listed under "Recommended Technologies and Practices" on EPA's Natural Gas Star Program web site: http://www.epa.gov/gasstar/techprac.htm **Differing opinion:** This technology may not be applicable in all cases, and needs careful consideration. Different formations typically require different completion techniques that this technology may not be suited to handle. E.g. many operators use compressed air to fracture coal wells. Air mixed with natural gas cannot be shipped to a pipeline due to the high potential for spontaneous combustion under typical pipeline temperatures and pressures. Additionally, oxygen contamination of natural gas causes additional corrosion risks to gathering lines. Separation of air from natural gas is presently not feasible or part of the process equipment used in "green completions."

B. Environmental

Nationally EPA has estimated that 25.2 billion cubic foot (Bcf) of natural gas can be recovered annually using Green Completions - 25,000 million cubic foot (MMcf) from high pressure wells, 181 MMcf from low pressure wells, and 27 MMcf from workovers. This reduces emissions of methane (a greenhouse gas), condensates (hazardous air pollutants), and nitrogen oxides (precursor to ozone formation and visibility degradation) formed when gas is flared. An EPA Gas Star Partner reported an estimated methane emissions reduction, as the total recovered from 63 wells, of 7.4 MMcf per year, which is 70 percent of the gas formerly vented to the atmosphere.

C. Economic

A methane savings of 7 MMcf per year based on completing 60 wells per year at the average recovery reported by an EPA Gas Star partner. The partner also reported recovering a total of 156 barrels of condensate from the 63 wells, an average of 2.5 barrels per well.
The capital costs include additional portable separators, sand traps, and tanks at a cost reported by the partner of $180,000. This equipment would be moved from well-to-well, so amortizing the cost over 10 years and doing 60 wells per year, the annual capital charges would be under $10,000. Incremental operating costs are assumed to be over $1,000 per year. At a natural gas price of $3 per Mcf and condensate price of $19 per barrel, green completions will pay back the costs in about 1 year. This information is for green completions in the Green River Basin area of Wyoming and is for much higher rate wells with much higher pressures and energy than the SJ basin wells.

IV. Background data and assumptions used

Information on Green Completions comes from EPA's Natural Gas Star Program web site: http://www.epa.gov/gasstar/techprac.htm

V. Any uncertainty associated with the option

Low, if the well is part of an in-fill and a sales line connection is available. Other situations may not be suitable for green completions.
Differing opinion: Very High – this is not a viable option for the SJ basin area – see above.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None.

Mitigation Option: Convert High-Bleed to Low or No Bleed Gas Pneumatic Controls

I. Description of the mitigation option

This option would encourage oil and gas producers and pipeline owners and operators to replace or retrofit high-bleed natural gas pneumatic controls. This option should be considered when replacement of pneumatic controls with compressed instrument air systems is not practical or feasible (e.g. no electric power supply). It would enhance EPA's current efforts in the Natural Gas Star Program and make them specific to the San Juan Basin. This would result in a significant reduction in methane emissions as well as achieve cost savings for the companies.

Pneumatic instrument systems powered by high-pressure natural gas are often used across the natural gas and petroleum industries for process control. Typical process control applications include pressure, temperature, liquid level, and flow rate regulation. As part of normal operation, natural gas powered pneumatic devices release or bleeds gas to the atmosphere and, consequently, are a leading source of methane emissions from the natural gas industry. High–bleed pneumatic devices are defined as those with bleed rates of 6 standard cubic feet per hour (scfh) or 50 thousand cubic feet (Mcf) per year. An EPA study in 2003 reported the constant bleed of natural gas from these controllers was collectively one of the largest sources of methane emissions in the natural gas industry, estimated at approximately 24 billion cubic feet (Bcf) per year in the production sector, 16 Bcf from processing and 14 Bcf per year in the transmission sector. Pneumatic control systems emit methane from tube joints, controls, and any number of points within the distribution tubing network.

Companies have found that the payback period can be less than a year for most retrofits from high-bleed to low-bleed pneumatic controllers. Recent experience indicates that up to 80 percent of all high-bleed devices can be replaced with low-bleed equipment or retrofitted. If electric power is available, conversion from natural gas-powered pneumatic control systems to compressed instrument air systems will result in greater methane emissions reductions. However, the investment payback period will likely be longer, and may not be cost effective in some cases.

In compressed instrument air systems, atmospheric air is compressed, stored in a volume tank, filtered and dried for instrument use. All other parts of a gas pneumatic system work the same way with air as they do with gas. Existing pneumatic gas supply piping, control instruments, and valve actuators of the gas pneumatic system can be reused in an instrument air system.
Reducing methane emissions from pneumatic devices by converting to instrument air systems can yield significant economic and environmental benefits for natural gas companies including:

- Financial Return From Reducing Gas Emission Losses. In many cases, the cost of converting high-bleed to low-bleed pneumatic controllers can be recovered in less than a year.
- Lower Methane Emissions

II. Description of how to implement

A. Mandatory or voluntary: This program would be voluntary. Due to the fact that almost all high-bleed pneumatics have been replaced by the industry, the economic returns from implementing low bleed systems should motivate producers to implement them. State and Federal agencies can assist by advertising the benefits, as is currently done by EPA's Natural Gas Star Program.
B. Currently most operators have already replaced all high bleed with low bleed systems.
C. Indicate the most appropriate agency(ies) to implement: EPA and the State environmental agencies would extend and enhance EPA's current efforts to make them specific to the San Juan Basin.

III. Feasibility of the option
A. Technical: These systems are off-the-shelf and proven.
B. Environmental: The environmental benefits of replacing high-bleed with low-bleed pneumatic controls, in terms of lower methane emissions, have been documented by EPA. Companies reporting to EPA have reduced emissions by 50-260 Mcf per year per controller.
C. Economic: EPA reports that replacing or retrofitting high-bleed units with low-bleed units have a payback of five to 21 months.

IV. Background data and assumptions used
See the website for EPA's Natural Gas Star Program: http://www.epa.gov/gasstar/index.htm

In particular, the lessons learned summaries for low-bleed pneumatics:
http://www.epa.gov/gasstar/pdf/lessons/ll_pneumatics.pdf

V. Any uncertainty associated with the option
Low. This is proven technology with proven benefits.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups
Cumulative effects should review oil and gas tasks and rank those most effective as priorities over those less effective or cost effective.

Mitigation Option: Utilizing Electric Chemical Pumps

I. Description of the mitigation option

This option involves replacing existing gas drive pumps with solar powered, electric-driven chemical pumps. The air quality benefits would be to minimize methane and VOC emissions to the atmosphere (Methane, VOC).

Economic burdens are significant but not insurmountable if the cost recovery factor from reduced fuel usage over the anticipated life of the unit shows a positive return on investment.

There should not be any environmental justice issues associated with installing and operating these units in socio-economically disadvantaged communities.

Differing opinion: This conclusion requires adequate support that is not included in this option.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of measures to install electric-driven, solar powered chemical pumps are envisioned as "voluntary" measures since the feasibility of installing insulation on new units or retrofitting existing units must be evaluated for a positive Net Present Value (NPV) or Return on Investment (ROI) in the Four Corners area. If the NPV or ROI meets a company's investment targets, then utilization of this technology should be encouraged as a best practice. There are no existing mandates by the respective Air Quality Control agencies to require electric drive pumps as BACT. Since the Four Corners area is not in ozone non-attainment and the cost economics will not always justify installation of insulation for economic benefit, a voluntary approach is recommended.

B. Indicate the most appropriate agency(ies) to implement**:** The states.

III. Feasibility of the option

A. Technical: The purchase and installation of electrically driven chemical pumps is technically feasible. Currently some companies are installing these pumps on a trial basis to assure performance during the winter months.

B. Environmental: The environmental benefits of reduced Methane and VOC pollution are well documented.

C. Economic: The use of electric-driven, solar powered chemical pumps is economically feasible where the there is payback that meets the respective companies targets for investments (i.e., ROI or NPV). For existing older pumps exist on wells that have a future limited life, the economics may not justify the application of insulation.

IV. Background data and assumptions used

Most chemical pumps in the Four Corners area are utilized year round to achieve their objective.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option

There is general agreement among working group members that the use of electrical chemical pump technology in the Four Corners areas is economically unfeasible and a likely source for voluntary adoption if the economics show a sufficient NPV.

Mitigation Option: Solar Power Driven Wellsites and Tank Batteries

I. Description of the mitigation option

This option comprises a system of production equipment and controls powered by solar generated electricity (through Photovoltaic – PV - cells) at gas well production sites that are not served with grid power. In most cases solar power replaces pressurized fuel gas, which is usually vented to the atmosphere after use. The power supply consists of solar panels and batteries. The solar power is used for electric instruments, controllers, actuators for automatic valves and small additive (methanol) pumps. Optimization consists of selecting the best fit items of hardware, becoming familiar with the strengths and limitations of all of the individual items as well as the overall system and making modifications to improve performance.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory on all new wellsites with gas-assisted chemical injection pumps. Mandatory where economic at existing wellsites. Propose to define a standardized calculation to determine if it is economic. An example borrowed from the Alberta EUB – Energy & Utilities Board – Directive 60, agreed to by a multi-stakeholder group including the oil & gas industry, includes the following:

1) Before tax basis
2) Point to an agreed upon specific gas forecast report
3) Must have remaining reserves calculation and production forecast (NPV calculated over life of well/production)
4) Only incremental capital costs related to the solar PV skid system may be included
5) Long term inflation based on CPI forecast
6) Discount rate = prime lending rate + 3%
7) Only revenue minus net royalties from incremental gas conservation only to be included
8) Economic if NPV before tax > $0

B. Indicate the most appropriate agency(ies) to implement**:** The States on State land or Federal/Tribe on Indian country.

III. Feasibility of the option

A. Technical: In the past two years an operator in Alberta has installed over 40 of these systems. Supported by operations managers, instrumentation personnel carried out trials with solar systems and electrical equipment to arrive at a "best fit" arrangement. In summer 2006, this operator carried out a study with outside specialist consultants in energy consumption and emissions monitoring to evaluate the performance of the system. The results of the study were very positive, resulting in this operator making their solar PV system the company standard for gas well production. The primary reasons for this are to reduce fuel consumption in producing operations, increase sales gas revenues and reduce vent gas emissions. There are also operators in the US Rocky Mountain area using solar PV systems in comparable ways.

B. Environmental: Reduced VOC emissions and reduced methane emissions (with a global warming potential ~23 times greater than CO_2). Quantity of reduction would be dependent on number and bleed rate of pneumatic controllers, and size and supply gas use rate of pneumatic pump equipment, being replaced with electrically-powered devices.

C. Economic: Reduced fuel gas consumption so increased gas conservation and saleable product. These solar PV systems also minimize the requirement for expensive fuel gas regulators, shutdown devices and repair kits and stainless steel instrument tubing and fittings.

IV. Background data and assumptions used
See the presentation, "BP Canada Energy Company Innovative Methods for Reducing Greenhouse Gas - Low Emissions Wellsite" by Milos Krnjaja, BP Canada made at the "Energy Management Workshop for Upstream and Midstream Operations: Increasing Revenue through Process Optimization & Methane Emissions Reduction" in Calgary, Alberta Canada on 15-17 January 2007.
(http://www.methanetomarkets.org/events/2006/oil-gas/docs/15jan07-bp_canada_energy_company.pdf)

See the presentation, "Using Solar to Reduce Fugitive Gas Emissions" by Stuart Torr, Komex International made at the 2005 Energy Conservation and Air Emissions Technology Forum Wednesday, in Calgary, Alberta Canada on 19 October 2005.
(http://www.ptac.org/eet/dl/eetf0501p12.pdf)

See Database of State Incentives for Renewables and Efficiency (DSIRE) for a fast and convenient method to access comprehensive information on available state, local, utility, and federal **financial incentives** that promote renewable energy and energy efficiency.
(http://www.dsireusa.org/)

See Alberta Energy & Utilities Board – Directive 60 – Upstream Petroleum Industry Flaring, Incinerating, and Venting.
(http://www.eub.ca/docs/documents/directives/Directive060.pdf)

See Ber-Mac Electrical and Instrumentation for an example of a supplier of solar PV systems for instrumentation use. They have been in business since 1980 supplying electrical power and instrumentation equipment and services, both domestically and to international markets, supplying the needs of oil and gas companies all over the world. Their "Green Machine" is an environmentally-friendly, solar-powered operating system for new and existing wellsites.
(http://www.ber-mac.com/greenmachine.htm)

V. Any uncertainty associated with the option Low – a fair amount of industry experience and vendor capacity to-date.

VI. Level of agreement within the work group for this mitigation option
General agreement within working group members that this is viable.

EXPLORATION & PRODUCTION: PNEUMATICS / CONTROLLERS / FUGITIVES

Mitigation Option: Optical Imaging to Detect Gas Leaks

I. Description of the mitigation option

This option would encourage oil and gas producers and pipelines to use optical imaging to detect methane and other gaseous leaks from equipment, processing plants, and pipelines.

Optical imaging refers to a class of technologies that use principles of infrared light and optics to create an image of chemical emission plumes. They offer more cost-effective use of resources than traditional hand-held emissions analyzers, can screen hundreds of components or miles of pipeline relatively quickly and allow quicker identification and repair of leaks. The remote sensing and instantaneous detection capabilities of optical imaging technologies allow an operator to scan areas containing tens to hundreds of potential leaks, thus eliminating the need to visit and manually measure all potential leak sites.

Gas imaging can be either active or passive. Active gas imaging is accomplished by illuminating a viewing area with laser light tuned to a wavelength that is absorbed by the target gas to be detected. As the viewing area is illuminated, a camera sensitive to light at the laser wavelength images it. If a plume of the target gas is present in the imaged scene, it absorbs the laser illumination and the gas appears in a video picture as a dark cloud. Because it relies on the detection of backscattered radiation from surfaces in the scene, the process is referred to as Backscatter Absorption Gas Imaging (BAGI).

Passive gas imaging is based on a complex relationship between emission, absorption, reflection, and scatter of electromagnetic radiation. VOCs in the vapor phase have unique spectral emission and absorption properties. By measuring these properties, the gas species can be uniquely identified. By tuning the instrument's spectral response to the unique spectral region of the VOC, the camera can make an image of a gas plume.

There is a variety of technologies available and in different stages of development for imaging hydrocarbon gases. Plume imaging technologies include BAGI and Hyperspectral Imaging systems. Remote detection sensing instruments include Open-path Fourier Transform Infrared (OP-FTIR), Differential Absorption Spectroscopy (DOAS), Light Detection and Ranging (LIDAR-DIAL), and Tunable Diode Laser Absorption Spectroscopy (TDLAS). These instruments can be hand held or shoulder mounted, van mounted, or operated from a helicopter or fixed wing aircraft, depending on the technology and the facility to be inspected.

As an example, the ANGEL service, which uses Differential Absorption Lidar (DIAL), can detect specific hydrocarbon gases with color video imaging from a fixed wing aircraft, quantify the plume concentration, encode GPS data on the image, and cover 1000 miles per day. This technology is most suited to a facility such as a pipeline or tank farm. For a gas processing plant, a hand held or shoulder mounted camera may be the technology of choice.

The benefits of using optical leak detection in an inspection and maintenance program include:

- Reductions in hydrocarbon gas emissions, both greenhouse gases and hazardous air pollutants;
- Improved safety; and
- Typical payback of less than one year in reduced methane product losses.

II. Description of how to implement

A. Mandatory or voluntary: This program would be a voluntary Best Management Practice. The economic returns from implementing optical leak detection should motivate producers to implement

them. State and Federal agencies can assist by advertising the benefits, as is currently done by EPA's Natural Gas Star Program.
B. Indicate the most appropriate agency(ies) to implement: EPA and the state environmental agencies would extend and enhance EPA's current efforts to make them specific to the San Juan Basin.

III. Feasibility of the option
A. Technical: Several of these systems are commercially available.
B. Environmental: The environmental benefits of using optical imaging to detect and repair leaks have been documented. Companies reporting to EPA have reduced emissions significantly. Individual company results can be found on the EPA Natural Gas Star Program web site referenced below.
C. Economic: EPA reports that optical leak detection surveys pay for themselves in less than a year.
Differing opinion: Must be evaluated for each operation, may not be economic or applicable for all.

IV. Background data and assumptions used
See the web site for EPA's Natural Gas Star Program: http://www.epa.gov/gasstar/index.htm

Individual companies' experience with optical imaging leak detection:

Dynergy: http://www.epa.gov/gasstar/pdf/ngstar_fall2005.pdf

Enbridge: http://www.epa.gov/gasstar/workshops/houston-oct2005/dodson.pdf

Also see the agendas from the 2003 – 2005 Gas STAR Program annual implementation workshops: http://www.epa.gov/gasstar/workshops/imp_workshops.htm

Information on the ANGEL-DIAL technology:
http://www.epa.gov/gasstar/workshops/kenai/itt_sstearns.pdf

http://www.epa.gov/gasstar/pdf/ngspartnerup_spring06.pdf

Texas Commission on Environmental Quality report that includes comparison of various imaging technologies: http://www.tceq.state.tx.us/implementation/air/terp/Prop_02R04.html

V. Any uncertainty associated with the option Low. This is proven technology with proven benefits.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None known.

Mitigation Option: Convert Gas Pneumatic Controls to Instrument Air

I. Description of the mitigation option

This option would encourage oil and gas producers and pipelines to convert pneumatic controls from natural gas to compressed instrument air systems. It would enhance EPA's current efforts in the Natural Gas Star Program and make them specific to the San Juan Basin. This would result in a significant reduction in methane emissions as well as achieve cost savings for the companies.

Pneumatic instrument systems powered by high-pressure natural gas are often used across the natural gas and petroleum industries for process control. Typical process control applications include pressure, temperature, liquid level, and flow rate regulation. As part of normal operation, natural gas powered pneumatic devices release or bleed gas to the atmosphere and, consequently, are a major source of methane emissions from the natural gas industry. The constant bleed of natural gas from these controllers is collectively one of the largest sources of methane emissions in the natural gas industry, estimated at approximately 24 billion cubic feet (Bcf) per year in the production sector, 16 Bcf from processing and 14 Bcf per year in the transmission sector. Pneumatic control systems emit methane from tube joints, controls, and any number of points within the distribution tubing network.

Companies can achieve significant cost savings and methane emission reductions by converting natural gas-powered pneumatic control systems to compressed instrument air systems. Instrument air systems substitute compressed air for the pressurized natural gas, eliminating methane emissions and providing additional safety benefits. Cost effective applications, however, are limited to those field sites with available electrical power.

In compressed instrument air systems, atmospheric air is compressed, stored in a volume tank, filtered and dried for instrument use. All other parts of a gas pneumatic system work the same way with air as they do with gas. Existing pneumatic gas supply piping, control instruments, and valve actuators of the gas pneumatic system can be reused in an instrument air system.
Reducing methane emissions from pneumatic devices by converting to instrument air systems can yield significant economic and environmental benefits for natural gas companies including:

- Financial Return from Reducing Gas Emission Losses. In many cases, the cost of converting to instrument air can be recovered in less than a year.
- Increased Life of Control Devices and Improved Operational Efficiency
- Avoided Use of Flammable Natural Gas. By eliminating the use of a flammable substance, operational safety is significantly increased.
- Lower Methane Emissions
-

The conversion of natural gas pneumatics to instrument air system is applicable to all natural gas facilities and plants where an electric power supply is available. For those sites that do not have electricity available, cost savings and methane emissions reductions can still be achieved by replacing high-bleed pneumatic devices with low bleed devices, retrofitting high-bleed devices, and improving maintenance practices. Experience has shown that these options often pay for themselves in less than a year.

II. Description of how to implement

A. Mandatory or voluntary: This program would be voluntary. The economic returns from implementing instrument air or low bleed systems should motivate producers to implement them. State and Federal agencies can assist by advertising the benefits, as is currently done by EPA's Natural Gas Star Program.
B. Indicate the most appropriate agency(ies) to implement: EPA and the state environmental agencies would extend and enhance EPA's current efforts to make them specific to the San Juan Basin.

III. Feasibility of the option
A. Technical: These systems are off-the-shelf and proven. Best utilized at larger facilities.
B. Environmental: The environmental benefits of replacing high-bleed pneumatic controls with instrument air, in terms of lower methane emissions, have been documented by EPA. Companies reporting to EPA have reduced emissions by an average of 20 Bcf per year per facility.
C. Economic: EPA reports that instrument air systems pay for themselves in less than a year. Replacing or retrofitting high-bleed units with low-bleed units have a payback of five months to one year.
Differing opinion: May not be economically justifiable or operationally sound for small facilities and well sites.

IV. Background data and assumptions used
See the web site for EPA's Natural Gas Star Program: http://www.epa.gov/gasstar/index.htm

In particular, the lessons learned summaries for instrument air:
http://www.epa.gov/gasstar/pdf/lessons/ll_instrument_air.pdf

And for low-bleed pneumatics:
http://www.epa.gov/gasstar/pdf/lessons/ll_pneumatics.pdf

V. Any uncertainty associated with the option Low: this is proven technology with proven benefits.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups None known.

EXPLORATION & PRODUCTION: MIDSTREAM OPERATIONS

Mitigation Option: Application of NSPS and MACT Requirements for Existing Sources at Midstream Facilities

I. Description of the mitigation option

Overview

- This mitigation option would involve filling in the gaps where the NSPS and MACT fail to adequately regulate sources at midstream facilities. Filing in the gaps could include lifting exemptions on existing sources and lowering applicability thresholds. Specific examples include:
  - Subjecting existing stationary combustion turbines at midstream facilities to 40 CFR Part 63, Subpart YYYY;
  - Requiring existing 2 stroke lean burn and 4 stroke lean burn reciprocating internal combustion engines to meet 40 CFR Part 63, Subpart ZZZZ MACT standards at midstream facilities;
  - Requiring boilers, reboilers, or heaters with a design capacity of less than 10 mmBtu/hr to meet NSPS at 40 CFR Part 60, Subpart Dc at midstream facilities;
  - Requiring all midstream facilities to meet the requirements to 40 CFR Part 60, Subpart KKK; and
  - Requiring all amine sweetening units at midstream facilities to meet 40 CFR Part 60, Subpart LLL requirements.

  This option would involve case-by-case assessments of midstream facilities to determine whether additional pieces of equipment should be regulated under NSPS and MACT standards and to assess the feasibility of such regulation. The overall goal is to use NSPS and MACT standards as guides for further air pollution reductions at midstream facilities.

Air Quality/Environmental

- This mitigation option would lead to further reductions in hazardous air pollutants and criteria air pollutants by subjecting more units to regulation. By requiring more facilities and/or units to comply with NSPS and MACT, there may be an incentive to upgrade to cleaner equipment, which would provide additional air quality benefits.

Economics

- There would likely be additional costs associated with bringing previously unregulated facilities and/or units into compliance.
- The option may provide an incentive to replace older, less efficient equipment, which could lead to increased efficiency.
- There would be potential paybacks associated with methane recovery by complying with NSPS at Subpart KKK.

Tradeoffs

- None.

Burdens

- The burden would be on industry to bring facilities and/or units into compliance with the NSPS and MACT standard. Air quality impacts would be reduced, reducing burden on health and welfare. Regulatory agencies may have to revise rules to implement this mitigation options.

II. Description of how to implement
A. Mandatory or voluntary: Mandatory. NSPS and MACT standards work best as mandatory requirements.
B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies, EPA.

III. Feasibility of the option
A. Technical: There will need to be case-by-case assessments, but this appears to be a technically feasible option.
B. Environmental: No environmental feasibility issues are known.
C. Economic: There may be economic concerns that should be addressed, but this option is not infeasible based on economics. The goal is clean air and that may take an investment.
D. Other: There will likely need to be rule changes to implement this option that may present feasibility issues.

IV. Background data and assumptions used
Background data and assumptions used came from review of EPA NSPS and MACT standards.

V. Any uncertainty associated with the option (Low, Medium, High):
Low uncertainty. The NSPS and MACT provide a solid basis for air pollution control options. However, further discussion and comments may reveal other means of using NSPS and MACT standards to keep air pollution in check.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups (please describe the issue and which groups: None.

Mitigation Option: Specific Direction for How to Meet NSPS and MACT Standards: Directed Inspection and Maintenance

I. Description of the mitigation option

Overview

Meeting NSPS and MACT standards at Midstream facilities can often be achieved using a variety of methods, some of which may be better than others. For example, the EPA is proposing to allow the use of infrared cameras to meet Leak Detection and Repair (LDAR) requirements set forth in several NSPS and MACT standards. 70 Fed. Reg. pp. 17401-17409. The EPA has indicated that infrared cameras can provide better data than Reference Method 21.

This mitigation option provides specific direction on how to meet NSPS and MACT standards so that the best methods of compliance are met. Specifically, it requires operators to use approved infrared cameras to meet LDAR requirements set forth at 40 CFR Part 60, Subpart KKK and 40 CFR Part 63, Subpart HH and HHH.

It would also require operators to implement cost-effective options for reducing methane emissions, as outlined in Fernandez, et al. 2005, to meet applicable NSPS and MACT standards. These cost-effective options would vary depending on the equipment, but would include using vapor recovery units on tanks and dehydrators, using desiccant dehydrators rather than glycol dehydrators, replacing compressor rod packing after three years, replacing gas starters on compressor engines with air starters, and converting gas pneumatics at facilities to instrument air.

Air Quality/Environmental

- Meeting LDAR requirements using infrared cameras promises to better keep volatile organic compound and hazardous air pollutant emissions from leaking equipment in check. Implementing cost-effective options for reducing methane emissions will further reduce emissions. In both cases, methane emissions would be reduced, preventing further greenhouse gas emissions.

Economics

- This mitigation option will most likely yield a payback due to the recovery of methane. According to one case study, BP recovered $2.4 million in 2 months simply by recovering over 123 MMcf/yr of that was lost due to equipment leaks (see, http://www.epa.gov/gasstar/workshops/hobbs72706/dim.pdf).

Tradeoffs

- The use of some cost-effective methane control options may require the use of electricity, such as vapor recovery units, which may be generated through coal or natural gas burning. Potential increases in emissions from electricity generation could be prevented through the use of solar or other renewable energy sources.

Burdens

- The only burden would be the restriction of flexibility for the operators and the investment cost.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory. Although infrared cameras and methane control options can provide paybacks and are proven cost-effective, they are not widely used. Despite potential paybacks, current incentives do not appear to be strong enough to encourage their use. Mandatory requirements would provide that incentive.

B. Indicate the most appropriate agency(ies) to implement: State air quality agencies and EPA.

III. Feasibility of the option

A. Technical: Feasible, these technologies are already in use and are being implemented elsewhere.
B. Environmental: Vapor recovery units may require additional space at midstream facilities and could pose additional environmental impacts. This seems to present a limited environmental feasibility issue.
C. Economic: Given the paybacks from methane recovery, there are no economic feasibility issues.
D. Other: The EPA has not yet finalized its proposal to allow infrared cameras to be used solely to meet LDAR requirements in the NSPS and MACT.

IV. Background data and assumptions used

Background data was obtained from information on the EPA's Natural Gas Star Program website, www.epa.gov/gasstar, from the EPA's proposal to allow infrared cameras to be used to meet LDAR requirements at 70 Fed. Reg. 17401-17409, and from the Fernandez et al. 2005 paper, "Cost Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers," available online at http://www.epa.gov/outreach/gasstar/pdf/CaseStudy.pdf.

V. Any uncertainty associated with the option

Low uncertainty, especially with regards to the use of infrared cameras as effective tools to comply with NSPS and MACT LDAR requirements. Operators would still have to show that cost-effect methane control options would meet the applicable requirements of the NSPS and MACT.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups

Possibly the Cumulative Effects Group due to indirect emission increases from coal or natural gas burning plants that may accompany increased use of vapor recovery units or other methane control options requiring electricity.

OIL & GAS OVERARCHING

Mitigation Option: Lease and Permit Incentives for Improving Air Quality on Public Lands

I. Description of the mitigation option

This option would provide incentives in the form of exceptions or waivers from lease stipulations or permit conditions of approvals (COAs) for oil and gas drilling on public lands in exchange for a program of environmental mitigation activities that would reduce air emissions along with other types of environmental and ecological impacts.

Differing Opinion: The proposed activities that would reduce air emissions and surface disturbance in this section should become standard practices **but without** the proposed exchange for the exceptions or waivers from seasonal wildlife restrictions which would negatively impact public lands wildlife.

This option could provide incentives in the form of expedited permit processing for operating permits in exchange for a program of environmental mitigation activities that would require documented reductions in emissions from major and minor sources. This option is not intended to reduce protection for wildlife. Monitoring and adjustments in response to monitoring results would be used to assure that the package of mitigation activities and associated development does not adversely affect wildlife.

Differing Opinion: Additionally these incentives would not include the exception of waivers from lease stipulations or permit conditions of approval ("COAs") for oil and gas drilling on public lands.

Expedited operating permit issuance from the appropriate agency in exchange for additional emissions reductions offers incentives for both industry and the agencies

Industry Incentives include:

- The streamlining of operating permits.
- Direct and prompt cooperation with permit issuing agency.
- Obtaining an operating permit at an accelerated rate allows for an accelerated startup date, thus increased resource production (may be especially helpful for minor source operating permits).

Environmental Incentives include:

- The addition of emission control equipment such as a catalyst, Zero Emissions (a.k.a. Quantum Leap) Dehydrator, directional drilling, complying with emission limitations relating to hours of operation, lean burn engine, and/or implementing a program of environmental mitigation activities that would reduce air emissions.

This option would work well in the areas that smaller agencies, such as Tribes, oversee the operating permits. This option would be implemented by the applicable permitting agencies.

It would be modeled after the experience in the Pinedale Anticline and Jonah fields in Wyoming where producers face seasonal limitations on drilling due to concerns about wildlife impacts. As a result, drilling is prohibited for several months during the year, delaying development and increasing costs. Several producers have applied for and been granted permission to drill year round in exchange for efforts that mitigate environmental impacts. These efforts combine improved technologies and innovative practices that together greatly reduce adverse impacts. They include: directional drilling to reduce the number of drilling pads, and thus the amount of surface disturbance, by half or more; using natural gas-fired drilling rigs to reduce air emissions; transporting produced water by pipeline to eliminate truck trips;

using mat systems on drilling pads to reduce surface impact; partial remediation of drilling pads after the drilling phase; eliminating flares during well testing and completion to reduce air emissions and noise; centralized fracturing and production facilities; low impact road construction techniques; and produced water recycling. Producers and BLM will monitor wildlife impacts as part of the program. Year round drilling has the added benefits of reducing the duration of drilling operations by one third-to one-half, and increasing stability of the local community as workers move in with their families, rather than commuting seasonally.

Differing Opinion: This suggestion of modeling after the experience in Wyoming's Pinedale Anticline and Jonah fields fails to address the widespread and significant concerns that have been expressed regarding current and future impacts of oil and gas activity on wildlife in these fields and the wildlife population declines that have been documented through scientific studies. The Pinedale Anticline and Jonah field experience has not proven to be a model for wildlife, and recent proposals to increase drilling may even adversely impact a federally threatened species, the Bald Eagle, and further exacerbate problems for the sage grouse, a species which some believe should be listed as federally endangered because of recent population declines. Another report that helps put the Jonah field experience in perspective came in December 2006, stating that in places one well was being drilled per every five acres. Repeated concerns about the impact on wildlife in these areas of Wyoming have been expressed by numerous and diverse groups of people ranging from private citizens, outfitters, hunters, environmental organizations, scientists, to government agency personnel including personnel from Wyoming's Game and Fish Department. Drilling exceptions granted in crucial big game winter range around Pinedale early winter 2006/2007 were granted in the face of opposition by Wyoming's Game and Fish Department.

Differing Opinion Continued: Monitoring has also not been a model experience in this area. According to reports of a May 2006, internal assessment Pinedale, Wyoming, Bureau of Land Management field office, the office neglected its commitment to monitor and limit harm to wildlife and air quality from natural gas drilling in western Wyoming. A wildlife biologist who worked in that Pinedale office, Steve Belinda, is reported to have quit his job because he and other wildlife specialists were required to spend nearly all their time in the office processing drilling requests and were not able to go into the field to monitor the effect of the thousands of wells on wildlife.

This option would involve tradeoffs between seasonal restrictions, which would be relaxed, and a comprehensive wildlife and environmental impact plan which would use the kind of technologies and practices listed above. This plan would reduce impacts on wildlife, as well as on air quality, land and water resources, and on the local communities. Ecological and environmental monitoring would assess these impacts and allow for adjustments in the plans as activities proceed. All of these elements would be contained in agreements between the land management agencies and industry, with public input.

Differing Opinion: Exceptions or waivers from wildlife lease stipulations or permit conditions of approvals (COAs) for oil and gas drilling on public lands likely would increase negative impacts of oil and gas activities on wildlife in the Four Corners. At least in Northwest New Mexico and likely in the other Four Corners states, it is important to remember that the seasonal closures in the Bureau of Land Management Farmington Field Office management area exist only for parts of the year with their length dependent upon the animal species and the reason for the restriction such as elk calving or antelope fawning. The restrictions are in place to protect species during times of the year when they are especially vulnerable such as nesting for raptors; wintering for deer, elk, and Bald Eagles; and birthing and caring for young for antelope and elk. Provisions for waiving, excepting, or modifying the oil/gas lease stipulations already exist according to the Bureau of Land Management Farmington Field Office's 2003 Record of Decision for Farmington's Proposed RMP and Final Environmental Impact. These restrictions should remain in place to protect wildlife, especially with the current and anticipated intensity of drilling.

Differing Opinion Continued: An indication of the major potential for the impact of oil and gas activity on wildlife is found in the 2006 Annual Report of the Sublette Mule Deer Study conducted in the Pinedale Anticline Project Area. Study results that "suggest that mule deer abundance in the treatment area declined by 46 % in the first 4 years of gas development."

Differing Opinion Continued: In the summer, 2006, publication of the New Mexico Department of Game and Fish titled New Mexico Wildlife under the regional outlook for Northwest New Mexico, wildlife biologists are reported to be "concerned about the effects the severely dry spring had on fawn survival in the state's **already depressed deer herds**." [Bolding is this author's.]

Differing Opinion Continued: Removal of the wintering restrictions for mule deer could create problems in New Mexico and in both this state and Colorado where migratory populations are shared. Another word of caution is found in the Upper San Basin Biological Assessment in the Comprehensive Wildlife Conservation Strategy (New Mexico's wildlife action plan accepted by the US Fish and Wildlife Service in 2006), which places mule deer in its list of Species of Greatest Conservation Need in the Colorado Plateau Ecoregion. Under "Problems Affecting Habitats or Species" in Chapter 5 of this document is this statement: "Of particular concern are energy development…" along with invasive species and livestock grazing practices. The document states that "coal bed methane development in the San Juan Basin is currently a major land use…Depending on the scale, density, and arrangement of each well site in relation to other sites, habitat loss and fragmentation in the portions of this habitat type [Big Sagebrush Shrubland] subjected to energy development are extensive. At this high level of development, effects may not be successfully mitigated."

Differing Opinion Continued: Pronghorn antelope numbers were so low at the time the Farmington Field Office's Draft Pronghorn Antelope Habitat Management Plan was published in March 2004, that the populations were described as struggling to survive, a change from when this species was common in the 1950's and 1960's. The restriction of drilling and construction activity during antelope fawning period from May 1 through July 15 was proposed as one of the ways to bring the populations back to eventual self-sufficiency.

These actions reduce air emissions from drilling rigs, from trucks (both diesel emissions and road dust), and from flaring. There are also benefits from reduced surface impacts and improved water management, as well as improved community stability.

Differing Opinion Continued: The actions that are offered that will reduce air pollution appear to be important ways to address our air quality problem and should become required practice because of the serious air pollution problems in the San Juan Basin. They should not come at an expense to area wildlife, which is already negatively impacted by direct and functional habitat loss due to oil and gas activities, as delineated in the 2003 Bureau of Land Management Farmington Field Office Draft Resource Management Plan and Environmental Impact Statement.

This option would work well in areas of the Four Corners region where new oil and gas projects are being proposed and where those projects face access limitations from wildlife stipulations or COAs. In these cases, the land management agencies (principally the BLM and the Forest Service) would have the greatest opportunity to negotiate agreements for infrastructure and operational changes from project start, in exchange for relaxing the access restrictions, along with monitoring for wildlife impacts. Monitoring of the air quality impacts, including documentation of reductions over similar projects without mitigation, would be required.

In New Mexico, this option could be integrated with the New Mexico Oil and Gas Association's (NMOGA) Good Neighbor Initiative.

Differing Opinion: Year round drilling will not improve air quality. The current drilling seasons are in place to protect the wildlife in the area. The improved technologies and innovative practices described above should be standard industry requirements and not be used in trade for expanded drill seasons.

Differing Opinion: BLM should not entertain compromising one environmental value in exchange for protecting another when industry is legally mandated to protect both. Year round drilling will only add to the stress wildlife currently experience in an already highly fragmented habitat. Even more, in the San Juan Basin industry has demonstrated their reluctance to routinely employ directional drilling as a means to avoid further habitat fragmentation. Since directional drilling "all wells" would be the cornerstone of the proposed mitigation option it seems that this options would not be favorably received by industry.

II. Description of how to implement

A. Mandatory or voluntary: This program would be voluntary and would rely on the operators, the agencies, and any local communities obtaining benefits from the arrangements.

B. Indicate the most appropriate agency(ies) to implement: BLM and the Forest Service on Federal land. State and tribal land management agencies may implement this option on state and tribal lands.

III. Feasibility of the option

A. Technical: The technological approaches to reducing impacts are already being implemented in Wyoming and other locations.

Differing Opinion: Four Corners states should use the technological approaches without industry cost being a factor.

B. Environmental: The environmental benefits of the mitigation measures are currently being documented in Wyoming. Many of them seem apparent. The impact of year round drilling (or other permit-related incentives) on wildlife would have to be closely monitored.

C. Economic: Many environmental mitigation measures turn out to be economically attractive as well (e.g., natural gas drilling rigs can reduce fuel costs by two-thirds). Year-round drilling can shorten the project length by one-third to one-half, improving project economics. Producers would have to anticipate an economic benefit in order to enter into agreements.

IV. Background data and assumptions used

Web sites and presentations from operators and BLM on the experience with this kind of agreement in Wyoming. The NMOGA web site has information on their Good Neighbor Initiative.

See the following web sites:
BLM environmental assessment of year-round drilling in the Pinedale Anticline Field:
http://www.wy.blm.gov/nepa/pfodocs/questar/01ea.pdf
(See especially section 2.5 on Applicant-Committed Mitigation.)

Questar presentation on development in Pinedale:
http://www.wy.blm.gov/fluidminerals04/presentations/NFMC/028RonHogan.pdf\

BLM assessment of year round drilling demonstration project in the Pinedale Anticline Field:
http://www.wy.blm.gov/nepa/pfodocs/asu/01ea.pdf

Jonah Infill Project:
Encana release: http://www.encana.com/operations/upstream/us_jonah_blm.html
BLM air quality discussion:
http://www.wy.blm.gov/nepa/pfodocs/jonah/92FEISAirQualSuppleQ-As.pdf
BLM EIS and Record of Decision: http://www.wy.blm.gov/nepa/pfodocs/jonah/

NMOGA Good Neighbors Initiative:
http://www.nmoga.org/nmoga/NMOGA%20Good%20Neighbor%20Initiative.pdf
Wyoming Mule Deer Study Report (1 site)
http://www.west-inc.com/reports/big_game/PAPA_deer_report_2006.pdf
Wyoming wildlife, sage grouse
http://stream.publicbroadcasting.net/production/mp3/wpr/local-wpr-563699.mp3
http://gf.state.wy.us/downloads/pdf/sagegrouse/Holloran2005PhD.pdf
Wyoming wildlife, Bald Eagle http://www.wy.blm.gov/nepa/pfodocs/anticline/seis/06chap3.pdf 3-97
http://www.wy.blm.gov/nepa/pfodocs/anticline/seis/07chap4.pdf 4-123
Wyoming Bureau of Land Management, wildlife monitoring (1site)
http://www.washingtonpost.com/wp-dyn/content/article/2006/08/31/AR2006083101482.html
New Mexico: Comprehensive Wildlife Conservation Strategy (CWCS)
http://fws-nmcfwru.nmsu.edu/cwcs/New_Mexico_CWCS.htm
New Mexico—2003 Bureau of Land Management Resource Management Plan/Environmental Impact Statement, Record of Decision http://www.nm.blm.gov/ffo/ffo_p_rmp_feis/docs/Farmington_ROD.pdf Appendix B

V. Any uncertainty associated with the option
Medium: Depends on opportunities (proposed projects) for implementing incentives in exchange for mitigation activities, on producer willingness to participate, and on BLM/FS state and regional office and tribal policy.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups Impacts from trucks and roads may overlap with the Other Sources work group.

Mitigation Option: Economic Incentives-Based Emission Trading System (EBETS)

I. Description of the mitigation option

The central idea of this option is that inherent economic incentives promote innovative ways to achieve emission reductions, including gains from efficiencies in operation and maintenance and in applications of new innovative engine and control technologies.

This option encourages the use of pollution markets through implementation of an emission trading system (ETS) along with cooperative partnerships to reduce air emissions with the aid of emission reduction incentives. Basically in an emission trading program, the governing authority (e.g., agency) issues a limited number of allocations in the form of certificates consistent with the desired or targeted level of emissions in an identified region or area. The sources of a particular air pollutant (e.g., NOx) are allotted certificates to release a specified number of tons of the pollutant. The certificate owners may choose either to continue to release the pollutant at current levels and use the certificates or to reduce their emissions and sell the certificates. The fact that the certificates have value as an item to be sold or traded gives the owner an incentive to reduce the company's emissions. Simply stated in an ETS, a producer who has low-emission engines could sell emissions credits to a producer who has high-emission engines. Typically, 0.8 units of credit could be sold for each unit of reduction below the standard or reference level. The end result is a ratcheting down of overall emissions. This option does not contemplate multi-pollutant trading, but rather a separate market for each individual pollutant.

Approximately 30 state and federal ETS programs existed or were being developed in the U.S. in the later part of the 1990s. Examples of ETS that have worked reasonably well in achieving emission reductions and providing economic incentives to industry include the Illinois EPA's Emission Reduction Market System (ERMS), Indiana Department of Environmental Management's credit registry trading system, U.S. EPA's Acid Rain Program, and commercial and non-commercial institutions like Chicago Climate Exchange (CCX). In addition, in 2002 the US EPA approved a plan submitted by the WRAP, which contained recommendations for implementing the regional haze rule. The plan included an SO_2 emissions allowance trading program for nine Western states and eligible Indian tribes. As an example, EPA's program took about three years to plan and begin implementing.

The proposed economic incentives based emission trading system (EBETS) mitigation option can be developed or modeled after ETSs which have been successful and tailored to issues specific to the Four Corner region. Emission credits can accrue through a variety of methods that are complementary to or independent of other mitigation options developed herein by the Task Force. For example, credits can be gained through use of partnerships that that provide incentives for voluntary emission reductions, such as in the EPA's Natural Gas STAR Program or New Mexico's VISTAS program (see the IBEMP mitigation option paper, OOP4). Credits for use or sale (e.g., sales within the ETS) can also be acquired through use of tax and/or lease incentives and through the initiatives coming from Small and Large Engine Subgroup (e.g., advanced ignition systems, use of electric engines, centralized large engine from many small engine mode of operations). In addition, opportunities exist for collaboration between engine manufacturers and producers for field testing new engine technology through a swap out program, dirty old for cleaner new. Finally, use of voluntary laboratory testing of a select group of existing engines (e.g. uncontrolled small, <300 hp, engines) could provide a means to identify innovative cost-effective modifications to improve engine efficiency and reduce engine emissions (SERP, 2006).

Benefits: Joint participation by oil and gas, electric power production, and other source category stakeholders provides opportunities for multi-pollutant emission reductions that cover key criteria air pollutants such as NO_x, SO_2, VOCs, $PM_{2.5}$, and PM_{10}. An added benefit could be realized by also including green house gases such as CO_2 and CH_4, in the mix. Examples of the emission reductions that could be achieved by a well designed and implemented ETS are the 50% reduction from 1980 levels of SO2 emissions from utilities under the ETS within US EPA's Acid Rain Program[1] and the 65% reduction from 1990 levels achieved under the Ozone Transport Commission NOx Program (SERP, 2006).

Tradeoffs: The ETS could be designed to provide for pollutant emission allocation and/or credit tradeoffs (e.g., NOx for SO2 in NOx limited regions) and trades between source groups or categories (e.g., oil and gas NOx with power plant SO_2).

Burdens: The major burden would be administrative in nature. Who would be responsible for designing, setting up and administering the proposed EBETS program and how would it be funded?

II. Description of how to implement

A. Mandatory or voluntary: Participation in the program would be voluntarily.

B. Indicate the most appropriate agency (ies) to implement: The states.

III. Feasibility of the option

A. Technical: The technical feasibility of ETS programs is well established and is in use around the world.

   Differing opinion: Accurately and reliably measuring the emissions from oil and gas sources will prove challenging. EBETSs have had broad success because those that have been established rely heavily on good monitoring and reporting, and it is not clear that such techniques are available for the oil and gas sources of interest. Parametric, as opposed to direct exhaust emissions monitoring is one option, but the less direct/accurate/reliable the measurement, the more likely it is that some offset/discount will be demanded to make up for the uncertainty, e.g., if a source wanted to purchase credits as part of its compliance plan, it would have to purchase two instead of one. Alternatively, sources with relatively weaker emissions monitoring would be allowed to purchase credits, but not sell them. This latter approach was taken in the WRAP SO2 Backstop Trading Program.

B. Environmental: The feasibility in achieving significant emission reductions has been clearly demonstrated through use of well designed and implemented ETS programs. Inclusion and addition of "Best Management Practices," innovative technologies, improved maintenance and other pay-back incentives enhance the feasibility of achieving emission reductions required to meet air quality and visibility enhancement goals in the Four Corners Region.

C. Economic: This program is economically feasible because emission trading provides economic incentives through implementation of complementary voluntary measures that reduce emissions, provide fuel savings, reduce operation and maintenance cost by adoption of BMPs and installation of innovative technologies. One recent study of projected economic gain by 2010 from the continued implementation of the ETS within the Acid Rain Program estimated it would provide an annual economic benefit of $122 billion (in 2000 $) at an annual cost of approximately $3 billion (or a 1 to 40 cost-benefit ratio).

[1] The success of the Acid Rain Program ETS is evident from emissions data, which shows that SO_2 emissions were reduced by over 5 million tons from 1990 levels or about 34 percent of total emissions from the power sector. When compared to 1980 levels, SO_2 emissions from power plants have reduced by 7 million tons or more than 40 percent.

IV. Background data and assumption used

1. United States Environmental Protection Agency (USEPA) Acid Rain Program < http://www.epa.gov/airmarkets/arp/index.html>
2. Illinois Environmental Protection Agency Emission Reduction Market System (ERMS) <http://www.epa.state.il.us/air/erms/>
3. Argonne National Laboratory, Strategic Emission Reduction Plan, Draft, 2006.
4. Chicago Climate Exchange < http://www.chicagoclimatex.com/>

V. Any uncertainty associated with the option Medium to high.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups

A key crossover issue to establishing and implementing an effective EBETS is the facilitation of voluntary participation of electric utilities and other major source groups. This will provide the anticipated needed trade-offs in air pollutants (e.g., NOx and SO_2) that participation by one or a limited number of source groups may not be able to provide.

Mitigation Option: Tax or Economic Development Incentives for Environmental Mitigation

I. Description of the mitigation option

This option provides for regulatory agencies and industry working together to utilize various legislative (state/federal/tribal) processes to achieve real emissions reductions. Emission reductions would be achieved by providing economic incentives that would encourage the industry to utilize lower emission internal combustion engines in various applications.

Emission reductions could be achieved through reducing the number of trucks in the field. This could be accomplished by providing incentives for companies to install underground piping in order to dispose of produced water. Criteria pollutants could be reduced by installing lower emissions compressor engines. Industry could be encouraged to install such engines by implementing tax incentives as described below.

Tax incentives provide economic relief to industry by reducing or eliminating taxes on certain equipment or activities. The equipment or activity must provide a recognized environmental benefit to the taxing entity that grants the incentive. Some examples of tax incentives currently being utilized are: (1) allowing costs of retrofitting existing engines or installing new engines to be fully deducted in the year they are incurred rather than being capitalized (2) tax credit certificates issued to program participants, which can be redeemed over a specified period of time (3) income tax credits upon installation of approved equipment.

The air quality benefits include net reduction of emissions, primarily of nitrogen oxides. However, reductions in sulfur oxides, greenhouse gas emissions and particulate matter emissions can also be calculated. Only positive environmental impacts have been identified. It is not anticipated that this strategy would cause any negative impacts, other than increased costs to industry. This strategy specifically provides for relief from such economic impacts.

Economic burdens include the cost to the oil and gas industry, engine manufacturers and other interest groups to develop and lobby legislative proposals. New technology would be more efficient, possibly resulting in increased production and reduced costs. The increased revenue would provide some offset to the initial costs of installation or retrofitting. Economic burden to the taxing entity would also occur. The taxpayers would, in effect, be subsidizing industry efforts to install or retrofit equipment to achieve lower emissions. Achieving taxpayer approval for such a subsidy might prove difficult.

Assistance from the Cumulative Effects Work Group could be helpful in estimating the potential cost-benefit of this option.

II. Description of how to implement

A. Mandatory or voluntary: Participation by industry or other groups would be voluntary, both in working to establish tax/economic development incentives and in taking advantage of such incentives.
B. Indicate the most appropriate agency(ies) to implement**:** States of Colorado and New Mexico. Counties of San Juan, NM; La Plata, CO; and other counties in the Four Corners area of impact. Indian tribes, including Jicarilla, Ute Mountain Ute, Southern Ute, Navajo, and others. These groups would need to work with state legislatures and/or Congressional representatives in getting sponsors to help draft an energy bill that includes tax incentives for improving Four Corners air quality.

III. Feasibility of the option

A. Technical: Many models of tax and economic development incentives are available. A list of some models follows, with more details contained in an Appendix to this document.

i. Mineral Tax Incentives and the Wyoming Economy, May 2001, is an economic model. http://legisweb.state.wy.us/2001/interim/app/reports/mineraltaxincentives.htm

ii. Brownfields Tax Incentive (1997 Taxpayer Relief Act P.L. 105-34). This model allows costs to be fully deductible in the year they are incurred, rather than having to be capitalized.

iii. New York State Green Building Initiative. This tax credit program was developed by New York State Department of Environmental Conservation as per 6NYCRR Part 638. Tax credit certificates are issued and can be redeemed at any time over a designated period (i.e. 2006 – 2014).

iv. Montana Incentives for Renewable Energy include property tax exemptions, industry tax credit, venture capital tax credits, and a low interest revolving loan program, special revenue local government bonds, and streamlined permitting processes for participants, income tax credits for retro-fitting equipment.

v. State of Virginia House Bill 2141, July 1997 allows the local governing body of any county, city, or town, by ordinance, to exempt, or partially exempt property from local taxation annually for a period not to exceed five years.

vi. US EPA's Voluntary Diesel Retrofit Program is a non-regulatory, incentive-based, voluntary program designed to reduce emissions from existing diesel vehicles and equipment by encouraging equipment owners to install pollution reducing technology. This option would easily fit into the "partnership" mitigation option. However, it is also a model for the type of equipment that might qualify for a tax incentive.

vii. Philippines Department of Natural Resources developed a single document that consolidates all tax incentives for air pollution control devices. Not new incentives, but a compilation of existing programs.

viii. Western Regional Air Partnership diesel Retrofit program for diesel engines could be used as a model for other internal combustion engines. The guidance document for developing a retrofit program is found on the WRAP website. See Appendix for information. This option would easily fit into the "partnership" mitigation option. However, it operates similar to a tax incentive program and gives an example of how to set up a workable program.

B. Environmental: The environmental benefits of pollutant emissions reductions are well documented.

C. Economic: The entire concept of this mitigation option is that it must be economically viable.

IV. Background data and assumptions used

See Appendix for background studies.

Cooperation between the regulated community; local, state and tribal governments; and equipment manufacturers would have to be garnered in order for this option to work.

V. Any uncertainty associated with the option Medium

VI. Level of agreement within the work group for this mitigation option

The three member drafting team expressed no disagreement with this option.

VII. Cross-over issues to the other source groups

These tax incentive programs could also apply to other sources, such as power plants or vehicles.

APPENDIX

Mineral Tax Incentives and the Wyoming Economy, May 2001, is an economic model.
http://legisweb.state.wy.us/2001/interim/app/reports/mineraltaxincentives.htm
This model can be used to show the effects of all tax incentives previously granted, as well as the effects of hypothetical tax incentives or tax relief that might be considered in the future. Impacts include reduction in taxes; increased production; effects on federal, state and local government revenues.

Brownfields Tax Incentive fact sheets (EPA 500-F-03-223, June 2003) and incentive guidelines (EPA 500-F-01-338, August 2001) can be found on US EPA's website at www.epa.gov/swerosps/bf/bftaxinc.htm There are also numerous case studies listed on this site as well as federal resources.

New York State Green Building Initiative credit certificates can be re-allocated to secondary users, if the initial recipient cannot utilize the entire credit amount. Information available at www.dec.state.ny.us/website/ppu/grnbldg/index.html or Pollution Prevention Unit (518) 402-9469; NY business tax hotline (518)862-1090 x 3311

Montana Incentives for Renewable Energy http://deq.mt.gov/Energy/Renewable/TaxIncentRenew.asp

Virginia property tax exemptions for the Voluntary Remediation Program
http://www.deq.state.va.us/vrp/tax.html

US EPA's Voluntary Diesel Retrofit Program information at
http://www.epa.gov/otaq/retrofit/retroverifiedlist.htm Includes a list of approved retrofit technology.

Philippines Department of Natural Resources lists many tax incentive and economic incentives at http://www.cyberdyaryo.com/features/f2004_0624_03.htm Also included are numerous links to related sites.

Western Regional Air Partnership guidance document for diesel retrofit programs can be found at
http://www.wrapair.org/forums/msf/offroad_diesel.html

Mitigation Option: Voluntary Partnerships and Pay-back Incentives: Four Corners Innovation Technology and Best Energy-Environment Management Practices (IBEMP)

I. Description of the mitigation option

This option encourages establishment of partnerships between oil and gas producers and federal, state and local agencies and with engine manufacturers. Examples of such voluntary partnerships that have worked successfully in reducing emissions and providing cost benefits to industry include the U.S. EPA's Natural Gas STAR Program, the New Mexico's Voluntary Innovative Strategies for Today's Air Standards (VISTAS) Program, Green Power and Combined Heat and Power Partnerships. The Natural Gas STAR Program is one of many voluntary programs established by the U.S. Environmental Protection Agency (EPA) to promote government/industry partnerships that encourage cost-effective technologies and market-based approaches to reducing air pollution. There are seven San Juan Basin producers[1] that are currently active members of the Natural Gas STAR Program. The VISTA Program is modeled after Natural Gas STAR.

This option involves establishing new partnerships or extending existing partnerships that encourage voluntary measures that reduce emissions and provide industry payback through improved operation and maintenance efficiencies. The IBEMP option is based on and is intended to extend upon the successes achieved in EPA's Natural Gas STAR Program and to complement the newly established VISTAS Program.

The central ideas of this option

- Increasing efficiency will result in more productivity, less emission, and increased revenue.
- Complementing EPA's Natural Gas STAR Program and VISTAS program to focus on the pollutants not covered in these programs
- Collection and use of the Best Management Practices (BMPs) from around the world, latest innovative technologies, and innovative solutions found by IBEMP members.

The air quality benefits include reduction of criteria pollutants such as NOx, SO_2, $PM_{2.5}$, PM_{10} as well as green house gases CO_2 and CH_4. The success of the EPA's Natural Gas STAR Program is well documented. According to the EPA's Gas Program, "Since the Program's launch in 1993, Natural Gas STAR Partners has eliminated more than 220 billion cubic feet (Bcf) of methane emissions, resulting in approximately $660 million in increased revenues." One Natural Gas STAR Partner has achieved the 18% to 24% fuel saving and reduction of 128 Mcf of methane emission per unit per year after installing an automated air to fuel ratio (AFR) control system called REMVue. According to engine manufacturers, new generation engines have benefits over older generation such as low operating cost, high thermal efficiency, low emissions, maintenance simplicity, and low repair cost which will help in recovering the cost of investment faster. An example of rapid improvement in the engine technology is the new Cummins-Westport engine, which is capable of peak thermal efficiency of close to 40% with 0.01 g/bhp-hr PM and 0.2 g/bhp-hr NOx emission. Even though Cummins-Westport engines and new generation engines from other engine manufacturers are geared towards transportation sector at present because of tighter emission standards, the improved engine technologies will help reduce the pollution in the other industrial sectors as the demand grows for efficient engines.

[1] BP, Burlington Resources, ConocoPhillips, Devon Energy, Williams Production, Energen Resources, and XTO Energy

Under this option, the time period to offset the cost of the replacing old engines with a new generation engines can be estimated through analysis of data from laboratory testing. Such data may be available from engine manufacturers or obtained through independent laboratory engine performance tests. The voluntary comparative laboratory performance and emissions testing (e.g., operating cost) and documentation would be performed by an independent test laboratory. In addition, voluntary laboratory and field-testing of a select group of existing engines (e.g., uncontrolled small, < 300 hp, engines) could provide a means to identify cost-effective modifications to improve engine efficiency and reduce engine emissions (Lazaro 2006, SERP).

Under this program the increased revenue from methane mitigation and fuel and maintenance savings can offset the cost of investment in the BMP and new technologies or equipment. In addition, under the proposed IBEMP option, partner members' mitigation efforts will be fully recognized and promoted similar to the recognition of partner contributions under EPA's Natural Gas STAR Program and New Mexico's VISTAS Program. Mitigation efforts can be recognized through awarding of emission credits (which can be traded in an emission market system, OOT-3). These efforts will also provide benefits to members through improved public and investor relations.

Since the IBEMP option is a voluntary program, participating members will have control or choice on mitigation decisions that are made. This provides opportunities for choices that provide a return on investments in best management practices and on new equipment and technology. As such, this option does not impose a burden on participating partners. Although, being a partner under this option would not relieve an operator from complying with non-voluntary measures or options, BMPs or other commitments made voluntarily under this option may facilitate compliance with other mandatory measures that may be adopted or come into play.

II. Description of how to implement

A. Mandatory or voluntary: The participation in the program is voluntarily

B. Indicate the most appropriate agency(ies) to implement: Through the New Mexico Environment Department under or a part of its VISTAS Program and/or in partnership with the Colorado Department of Public Health and Environment. The USEPA Gas Program may also be interested in collaborative partnerships with the Four Corners Air Quality Task Force.

III. Feasibility of the option

A. Technical: The success of the EPA's Natural Gas STAR Program is a clear indicator of the technical feasibility of this program.
B. Environmental: The Best Management Practices, including equipment upgrades are well established in the oil and gas industry and adoption of these measures will provide opportunities for significant and achievable emission reductions.
C. Economic: This program is economically feasible because innovative technologies and BMPs will result in increased productivity, fuel saving, and environmental benefits, which in return offset the cost of investment. The previously referenced EPA Natural Gas STAR Program example illustrates that significant savings can be achieved in reduced fuel consumption (e.g., in one case that covered 51 engines reduction in excess of 2,900 MMcf or an average of 78 Mcf per day per engine, when adjusted for load, was achieved over a two-year period). The final payout period was 1.4 years by taking into consideration of fuel saving of $4.35 million at a nominal value of $3/Mcf.

IV. Background data and assumptions used

1. United States Environmental Protection Agency (USEPA) Natural Gas STAR Program <http://www.epa.gov/gas/>

2. New Mexico San Juan Voluntary Innovative Strategies for Today's Air Standards (VISTAS) <http://www.nmenv.state.nm.us/aqb/projects/SJV/index.html>
3. Engine Manufacturers: <www.cat.com>, <www.cummins.com>, <www.cumminswestport.com>.
4. Argonne National Laboratory, Strategic Emission Reduction Plan, Draft, 2006
5. Near-term commercial availability of small clean efficient engines
6. Near-term commercial availability of advanced engine technology

V. Any uncertainty associated with the option Low to medium.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups
Establishing and implementing an effective IBEMP is the facilitation of voluntary participation of San Juan oil and gas producers. There are no key crossover issues with other source groups.

Mitigation Option: Voluntary Programs

I. Description of the mitigation option

Overview
This option describes voluntary programs to implement mitigation strategies and achieve air quality benefits that are above and beyond the requirements of regulations and permits. This option is not meant to replace the *Voluntary Partnerships and Pay-back Incentive* mitigation option, nor is this option meant to indicate voluntary implementation should be applied to existing or future requirements necessary for improvement of air quality. There are situations in which mandatory measures are the only system that will result in emissions reductions that are high-impact, consistent, and necessary. There are also situations in which voluntary implementation of strategies may be a method to achieve emissions reductions in a time- and cost-effective manner. Voluntary programs allow participants to demonstrate their commitment to the issue and to local communities. Challenges to success with voluntary programs include publicizing a program to make it well-known, creating a list of strategies and technologies that may be implemented voluntarily, offering incentives sufficient to attract program participants, and quantifying emissions reductions adequately and consistently to estimate results.

Air Quality and Environmental Benefits

- Air quality improvement because voluntary measures would achieve emissions reductions beyond regulatory and permitting requirements.
- Depending on strategy/technology, other environmental benefits may exist.

Economic

- Capital investment from participants for voluntary measures and reporting.

Trade-offs

- Air quality improvement
- Positive public relations
- Agency's costs for administration and tracking.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary. The New Mexico Environment Department already administers a voluntary program called VISTAS (Voluntary Innovative Strategies for Today's Air Standards) that is modeled after EPA's Natural Gas STAR Program. To increase implementation, the agency could compile of list of mitigation options not otherwise required by regulation or permit, as a list of "qualifying" voluntary measures for VISTAS. More information about VISTAS is available at: http://www.nmenv.state.nm.us/aqb/projects/SJV/index.html. Quantification of benefits and measurement of other results is essential to ensure accountability in a voluntary program and increase likelihood of success of the program. In addition, participants or the administrator of a voluntary program should describe voluntary actions by producing "Lessons Learned" papers, which are short descriptions of practices and technologies employed, benefits and challenges, feasibility, and implications for future use of the same voluntary actions.
B. Indicate the most appropriate agency(ies) to implement: State Environmental Agencies

III. Feasibility of the option

A. Technical: Good feasibility due to flexibility and choices regarding participation and specific technology(ies) implemented. Potential voluntary measures for the oil and gas industries may include, but are not limited to, the following:

- Plunger lift cycles for removal of liquid buildup and minimizing well blowdowns.
- Device on tanks to control over-heating, such as bands of insulation.
- Electrification where possible.
- Centralization of tank batteries to decrease truck traffic.

B. Environmental: Excellent feasibility, however environmental benefits depend on control strategies. Select control strategies may have other air or non-air environmental impacts, such as SCR's ammonia slip.

C. Economic: Feasibility depends on incentives. Economic feasibility often increases in response to incentives. Participation in voluntary programs for companies is often based on a cost/benefit economic analysis, and incentives can provide a deciding factor. Potential incentives would be determined by the implementing agency and may include the following:

- "Good Citizen" marketing
- Alternative to regulation, if any exist
- Paybacks/savings
- Consideration for expedited permits, if possible
- Parametric monitoring less strict or other requirement leniency, if possible
- Tax credit/royalty rate reduction
- For Federal land, modification in standard stipulations, if possible.
- "Credit" given like an Environmental Management System on compliance history

IV. Background data and assumptions used

Natural Gas STAR and San Juan VISTAS, both voluntary air programs in the Four Corners region.

V. Any uncertainty associated with the option High. Voluntary programs do not guarantee emissions reductions, nor are emissions reductions enforceable. Quantify of reductions through reporting may lessen uncertainty but do not guarantee or enforce reductions.

VI. Level of agreement within the work group for this mitigation option Medium. This option write-up stems from a discussion at the November 8, 2006 meeting of the Oil and Gas Work Group.

Some members of the work group expressed concern that mandatory application of the strategies outlined in this document prior to analysis by a regulatory agency may preclude consideration of advantages and disadvantages from voluntary programs. There was also some discussion of the concept of criteria for establishing whether a mitigation strategy is applied under voluntary or mandatory conditions should be developed to enhance capability for implementation of the options. These criteria would provide an important tool to agencies considering options by better defining feasibility. Additionally, voluntary application of the mitigation strategies would facilitate the development and efficient implementation of these options via a "lessons learned" approach where mandatory application may prematurely dictate the method of implementation.

VII. Cross-over issues to the other source groups

If a voluntary program has a wide range of participants, there are many cross-over issues to other source groups in terms of what voluntary measures could be implemented by those sources.

Mitigation Option: Cumulative Inventory of Emissions and Required Control Technology

I. Description of Mitigation Option

The Four Corners Region is a hotbed of oil and gas activity. There are more than 20,000 oil and gas wells in the San Juan Basin and at least 12,500 additional new wells are proposed within the next 20 years. Oil and gas facilities are being located in remote areas and in neighborhoods and cities. The City of Bloomfield, NM, population of 7,200 people, has at least six major oil and gas processing facilities in very close proximity. A large elementary school near the cluster of these facilities north of Bloomfield was evacuated in 2006 due to an accidental release of noxious emissions from one of these gas plants.

A cumulative inventory of total emissions from the large oil and gas facilities near densely populated areas should be conducted prior to the permitting of additional facilities. It has been reported that at least one new, large, petroleum processing facility is on the drawing board for the Bloomfield area.

All oil and gas facilities, large or small, should be required to report all emissions to appropriate governing agencies annually. A cumulative inventory of emissions is necessary.

Installation of best available technology emission control equipment on ALL oil and gas facilities should be MANDATORY to greatly reduce the release of pollutants into the environment. All internal combustion engines should be required to be fitted with catalytic converters.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory.

B. Indicate the most appropriate agency (ies) to implement: States of New Mexico and Colorado.

III. Feasibility of the option

A. Technical: is not clear whether the intent was to have a yearly report of emissions output based on continuous emissions monitoring for all pollutants (very expensive), or if the intent was to have the operators estimate the amount of emissions based on what sources had been operational during the year. Option also needs to define what levels of the given pollutants would be acceptable to assess feasibility.
B. Environmental: None
C. Economic: None

IV. Background data and assumption used

Bloomfield area ozone levels are already periodically high according to monitoring. Any consideration of permitting additional large oil and gas facilities near Bloomfield should include risk of increasing levels of ozone.

An example:
The North Crandall Compressor Station located within the City of Aztec is permitted by NMED Air Quality Bureau at 176.3 tons/yr (tpy) of Nitrogen Oxides (NOX), 39.4 tpy of Carbon Monoxide and 75.9 tpy of Volatile Organic Compounds (VOC's). There is a warning sign on the fence that states "Warning Hazardous B.T.E.X. emissions may be present." B.T.E.X. compounds are toxic to humans and wildlife. Several homes are located near this facility.

In comparison to the refineries and gas processing facilities in the Bloomfield area, the Williams Crandall Compressor Station is small but it is permitted to emit about 292 tons of pollutants per year into the atmosphere. Cumulative permitted emissions from the very large Bloomfield facilities are unavailable at this time.

Oil and gas facilities are sources of many hazardous pollutants such as NOX, SOX, VOC's, methane, hydrogen sulfide, etc. Many of these pollutants contribute to respiratory diseases, cardiac diseases and some of them are carcinogens. Hydrogen sulfide is a deadly neurotoxin.

V. Any uncertainty associated with the option None.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups TBD.

Mitigation Option: Mitigation of Hydrogen Sulfide

I. Description of Mitigation Option

Hydrogen sulfide (H_2S) is a deadly neurotoxin. Since H2S contamination is becoming more widespread, for the safety of the public and the oilfield employees ALL wells should be tested for H2S by the well operators at least twice per year and the test results reported to appropriate agencies.

The companies provide H2S training and monitors for the employees. The employees are trained to be aware of H2S, but the general population is not. The typical rotten egg smell is a familiar warning to oilfield employees, but the general population who lives in close proximity to H2S wells are not informed about the dangers of an H2S release.

Public information programs on the dangers and toxicity of oil and gas pollutants and most importantly H2S, must be made available to the people. Ideally, gas wells and refineries should be isolated away from the general population; however, oil and gas facilities are being established in populated areas and vice versa. Houses are being built next to oil and gas sites. For the health of the public, exposure to H2S and other petroleum related toxics must be prevented.

II. Description of how to implement

A. Mandatory or voluntary: Mandatory.

B. Indicate the most appropriate agency (ies) to implement: The companies and the States of New Mexico and Colorado.

III. Feasibility of the option

Not considered.

IV. Background data and assumption used

For H2S information, do a Google search on Dr. Kaye H. Kilburn MD, and Professor of Medicine at the University of Southern California. He is a leading researcher on chemicals such as hydrogen sulfide and diesel exhaust.

The Bureau of Land Management has been collecting data on the wells contaminated by hydrogen sulfide in the San Juan Basin.

Quick statistics are as follows:

- More than 375 wells test positive for H2S
- H2S is present in at least 5 formations
- 11 producers have reported H2S wells
- A lot of the small producers did not report, so these numbers are likely higher.

Sour gas (H2S) fields are common in Colorado and New Mexico. New Mexico has a State Regulation with an ambient air quality standard for H2S; however, it is reported that NMED does not have H2S measuring equipment. H2S must be closely monitored and controlled by the companies and the State and Federal agencies. It can be deadly.

V. Any uncertainty associated with the option TBD.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other source groups TBD.

Mitigation Option: Encourage States Importing San Juan Basin Natural Gas to Require Pollution Control at the Source

I. Description of the mitigation option

States that import San Juan Basin natural gas should require the gas be produced and transmitted in an environmentally clean method. End users should have a responsibility for the sources of pollution generated from natural gas production.

Recent California legislation banning importation of power from sources that generate more greenhouse gases than in-state natural gas-fired plants leads to this related issue.

Much of the natural gas used in these plants as well as in the residential sector is imported from other states or other countries. One published article[1] states that 85% of the natural gas used in California is from out-of-state and that one-quarter of this comes from the San Juan Basin. Other states may also be using San Juan Basin natural gas. It is disingenuous for states to claim to be producing clean power or using clean gas for residential use when the production of fuel for that "clean" power plant or clean burning appliance is creating serious air and water quality problems at the source of the fuel. If the user states are seriously concerned about improving air and water quality they should address out-of-state impacts as well as in-state impacts.

II. Description of how to implement

A. Mandatory or voluntary:
Adoption of a "clean fuel import policy" by user states would necessarily have to be voluntary. However, the application of such a policy by a user state, once adopted, could and should be mandatory for fuel importers.

B. Indicate the most appropriate agencies to implement:
Implementation of the policy in user states could be by the regulatory agencies or commissions charged with oversight of investor-owned or publicly-owned electric utility systems. In some cases legislation may be necessary to implement this policy.
There is a need to develop an inventory, state-by-state, of customers who are importing natural gas from wells in the San Juan Basin. The first step in implementation would involve contacting user states and urging adoption of policy or legislation requiring importation of "clean" natural gas; a definition of "clean" must be developed.

III. Feasibility of the option

A. Technical:
It may be difficult to develop a good working definition of what constitutes acceptably "clean" natural gas. This is also a legal issue and one must work within the framework of the Federal Clean Air Act and Clean Water Act as well as individual state statutes.

B. Environmental:
Should be feasible

C. Economic:
Could eventually lead to higher costs for electricity in user states due to the rightful inclusion of environmental costs of fuel production.

D. Political:
Could be very difficult to implement in some states

IV. Background data and assumptions used

Assumption that most natural gas produced in the San Juan Basin is exported to other states. The figures cited in Section I should be checked/verified.

V. Any uncertainty associated with the option
Yes; response of user states unknown.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other Task Force work groups
Significant cross-over to the Power Plants and Oil & Gas Work Groups

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[1] *High Country News*, Dec. 25, 2006, p. 12.

OIL & GAS: PUBLIC COMMENTS

Oil & Gas Exploration & Production Public Comments

Comment	Mitigation Option
If "many companies BMPs in place already," then why does a mandatory approach to BMPs seem implausible. This should be a cost of doing business in this area; a cost that is well-absorbed by most other companies.	Best Management Practices (BMPs) for Operating Tank Batteries
VRU's have one big technical problem not addressed, the introduction of air in the gas. Air is made up of Nitrogen and Oxygen two contaminates that the gas pipeline companies refuse to take into their system. If one VRU allows air to enter the gas system, then the whole gas system must be shut down or flared in the field. The gas companies must be forced to take air in reasonable quantities into their system. The gas pipelines will argue that it is unsafe, if that is true then all the gas supplying houses in the Colorado front range must be shutdown because air is added to improve quality.	Installing Vapor Recovery Units
In the 60's and 70's this type of water removal was tried in the northern Rockies. The amount of saltwater disposal was huge and the beds may only last a day or two before they must be changed.	Dehydrators / Separators / Heaters
Glycol pumps are a critical item and any replacement system must have a high reliability. 5KW generators will had NOx, CO, CO2 and decrease reliability. Kimray pumps with flash gas separators reduce emissions and keep the system reliable. the gases recovered from the pump gas separator can be used for fuel MOST of the time. In some cases where the gas stream is high in liquefiable hydrocarbons (those with molecular weights higher than 40) the pump gas separator vapors will not burn reliably or completely cause unreliable operators and increased emissions. In the case of gases with high liquefiable content, vent gases need to be flared (burned).	Zero Emissions (a.k.a. Quantum Leap) Dehydrator
We strongly agree that an initial voluntary monitoring effort, followed by mandatory reporting and monitoring requirements, should be initiated by the operators to measure concentrations and species of VOCs and HAPs and other flaring by-products.	Venting versus Flaring of Natural Gas during Well Completions
We strongly agree that co-location and centralization of new oil/gas field facilities should be voluntarily implemented by operators. We also agree with the approach of state and federal agencies and mineral management agencies proactively integrating this approach into planning and permitting processes.	Co-location / Centralization for New Sources
The present laws will not allow this option. TEG (glycol) units must be permitted at a maximum rate. In the Rockies the maximum rate is only required for a few months during the year. Good operators adjust their pumps as needed to save fuel and lower emissions, but they get not credit for doing so because their permits are set. GLYCALC uses all kinds of default assumptions, this does not replace good engineering and the ability to make real life adjustments. Other design and simulation programs should be allowed without any legal ramifications.	Control Glycol Pump Rates
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Control Glycol Pump Rates
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Convert High-Bleed to Low or No Bleed Gas Pneumatic Controls
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Optical Imaging to Detect Gas Leaks

Comment	Mitigation Option
Instrument gas or instrument air is used to control facilities. These controls maintain the emission control system, gas quality controls and safety shutdown systems. If the instruments air/gas system lacks sufficient quantity and quality, the controls will fail and emissions, quality and safety devices can fail with undesirable results. At small and remote sites air compressors will be unreliable and gas must be used.	Convert Gas Pneumatic Controls to Instrument Air

Oil & Gas Stationary RICE Public Comments

Comment	Mitigation Option
The SUGF agrees that new air quality management strategies such as this option should be implemented to address cumulative air quality impacts. It is highly recommended that this option be considered by the regulatory agencies and be applied to both new and existing engines, particularly units of less than 300 horsepower. Although horsepower levels are lower and operating hours may be limited, emission rates of these smaller units are higher than larger units. As a single source, emissions may be minimal, but collectively with other area sources it may have a cumulative affect.	Industry Collaboration
Comments below are specific to the mitigation option as currently written, which assumes the power requirement would come from the power grid. A second alternative is also provided below as a sub option assuming the power comes from on-site generators. We recommend including both alternatives to this option. Comments are also provided on the analysis of this option under the cumulative effects section of the public draft report. Install Electric Compression (re-label as Alternative 1 - Power Grid, see recommended Alternative 2 addition below after comment # 6) 1. The overview is not consistent with overviews written for other mitigation options covered in the Task Force Report. As written, the overview presents a rather biased view on the viability of this option. The overview should provide a description of the option without any discussion about the option's technical or economic feasibility. Possible physical restriction or modification requirements on installation for specific compressors should be removed and discussed under Sec III. Feasibility of the option, A. Technical. The last two sentences on the electric grid should also be moved to the feasibility discussion or deleted. Under the mitigation option overview, we recommend inserting the following: The selection of combustion engines for electric compression should be on case-by-case basis which will allow the flexibility of evaluating necessary compressor interface modifications such as re-gearing to accommodate electric motors. 2. The discussion and emission table under Air Quality/Environment is inconsistent with discussions covered in the other mitigation options and should be deleted. Please see our comments on the Cumulative Effects section analysis of this option. The nationwide averages of emissions from power plants operated by the three identified companies would not be representative of the power supplied from the Western Power Grid. We recommend inserting the following under the mitigation option overview:	Install Electric Compression

Comment	Mitigation Option
The noise from continuously running internal combustion engines can be an issue for the nearby residents. The switch to electric motors will also help cut down the noise in the oil and gas operation. 3. The economics as written only covers the costs of the option if implemented. To provide a balance picture both costs and economic benefits should be covered. The following points should be included in the discussion: a. In case of electric motors connected to power grid, there is virtually no maintenance cost. b. The electric rates in the night are cheaper compared to peak times. This will result in additional saving for oil and gas industry. c. The need for less maintenance of electric motors and localized electric grid will result in fewer maintenance trips for the oil and gas workers which will help in controlling dust as well as minimize impact on the wild area in the four corners region. In the second bullet not sure what specific maintenance and repair costs we be borne by producers that are associated with the electric power source for electric compression. Maintenance and repair of substations and transmission lines, from the grid to substation, are typically borne by electric generators and included in rates to consumers. The last bullet on suppliers/manufacturers is more an implementation issue than an economic issue. We recommend moving this discussion to description on how to implement. 4. Tradeoffs - We recommend striking any reference to new co-generation plants as means to supply power for electric compression, since the electric compression option requires no thermal power. As previously stated current plans for electric power generating within the western regional power grid should be adequate to meet even the most optimal electric compression demand that might develop. 5. Burdens - Since implementation of electric compression is voluntary the producers can evaluate which compressor conversions to electric are economically feasible. Economic burdens over the long term can be minimized and possibly turned into economic gain based on careful evaluation of return on capitol expenditures (e.g., lower electric motor vs. RICE engine maintenance costs). The assumed requirement for new electric power generation to support electric compression is speculative, since the degree of implementation of this option producer specific. We recommend deleting the sentence on capitol investment for new power plants. Also, existing plans for new generation may be sufficiently adequate to meet reasonably anticipated power requirements for implementing this option. We recommend consultation with the Power Plant Workgroup. 6. II. Description of how to implement and feasibility of option - See above comments. 7. III. Feasibility of the option, C Economics - On economics, we agree that costs need to be evaluated, including the economic benefits, as previously mentioned. The need for modeling (air quality) to evaluate the air quality	

Comment	Mitigation Option
benefits is true about all of the options. Also, the planned modeling to address cumulative regional air quality impacts is discussed elsewhere in the draft report. We recommend deleting the sentence. ON-SITE ELECTRIC GENERATOR ALTERNATIVE TO GRID POWERED ELECTRIC COMPRESSION As written the current option identifies only one source of electric power, power from the grid. A second alternative to this option would be to supply power to the electric motors using local dedicated low-emission natural gas lean-burn electric generators. The electric compression using the lean-burn electric generator should be included as a second alternative for the "Install Electric Compression" mitigation option. We recommend that the Four Corners Air Quality Task Force add the following language to the Install Electric Compression mitigation option: Mitigation Option: Install Electric Compression (Alternative - On-Site Generators) I. Description of the mitigation option Overview - As an alternative to grid power dedicated on-site natural gas-fired electrical generators can be used to supply power to electric motors that replace the selected RICE compression engines. The electric motors would be rated at an equivalent horsepower to that of RICE engines currently used for gas compression. The power sources for the electric compression could consist of a network of on-site gas-fired electrical power generators. The alternative could be expanded to include consideration of replacement of other engines, such as, gas-fired pump-jack engines used as "prime-movers." The currently available gas electric generator run on variety of fuels including low fuel landfill gas or bio-gas, pipeline natural and field gases. The gas electric generators are available in the power rating from 11 kW to 4,900 kW. Decisions on the use of on-site generators to replace natural gas-fired engines and the number of generators required would depend on a number of factors, including the proximity, spacing and size of existing engines. As a simple example using the conversion factor of 1 MW = 1,341 HP, adding a 1 MW natural gas-fired generator could replace an inventory of approximately 33 small (40 hp) internal combustion engines if these were reasonably close proximity, say spaced within a one or two mile radius. However, in "real world" operations, there will be several factors involved in determining the number of required gas-fired electrical generators; such as transmission loss, ambient operating temperature, load operating conditions, pattering of applied loads, etc. Air Quality/Environmental Benefits The emissions from gas electrical generators are relatively low compare to smaller internal combustion engines because of new technology and ability of controlling emission from big engines. For example a Caterpillar G3612 gas electrical generator with power rating of 2275 kW emits 0.7 gram/hp-hr NO_x at 900 rpm which is equivalent to 0.0009387 g/W-hr. For comparative illustration with alternative 1, if you assume …. As stated in the mitigation	

Comment	Mitigation Option
option; "Control Technology Options for Four Corners Power Plant" (FCPP), the NOx emission from FCPP is approximately 0.54 g/mmBtu. Based on the assumption that efficiency of FCPP is 40%, the NOx emission from FCPP is approximately 0.002099 g/W-hr. This comparison shows that the gas electrical generator is more environmentally friendly then using power from a coal based power plant. The baseline average emission for the Western Grid should be used to calculate the real emission difference between installing a lean burn electric generator to replace combustion engines. The noise from continuously running internal combustion engines can be an issue for the nearby residents. The switch to electric motors will also help cut down the noise in the oil and gas operation. The need for less maintenance of electric motors and lean burn electric generator will result in fewer maintenance trips for the oil and gas workers which will help in controlling dust as well minimize the impact on wild area in the four corners region. Economics The initial capitol cost of installing gas electrical generator and electrical motor would be relatively high. As an example, a generator of 1 MW capacity can approximately support 33 combustion engine of 40 HP. A general purpose 40 HP engines costs about $1200.00 which results in capital cost of $39,600 for replacing 33 internal combustion engine with electric motors. The approximate cost of a 1.2 MW gas-fired generator is $430,000. The total capital cost for replacing 33 engines with a gas fired generator will be about $470,000. However in long term the benefit in terms of emission reduction and saving in maintenance cost should help in recovering the initial capital cost. The maintenance cost of one big generator is cheaper than maintenance of many smaller internal combustion engines. The cost of running electrical wires to connect electric motors will much less than currently installed pipelines to carry natural gas for the small rich burn combustion engines. Tradeoffs In case of gas electric generators, there will be shift of emission from many internal combustion engines to one or several big internal combustion engine(s). There would be a net reduction in emissions which will depend on degree of conversion that each producer deems economically feasible. The cost and affects of running transmission lines from generator(s) to power electrical motors for gas compression needs to be evaluated. Burdens The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry. II. Description of how to implement	

Comment	Mitigation Option
A. Mandatory or voluntary: Voluntary, depending upon the results of monitoring data over time. B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies. III. Feasibility of the option A. Technical: The feasibility mainly depends on the close proximity of replaceable internal combustion engines and operating conditions of internal combustions engines in order of selection of gas electrical generator. The power, transmission line and substation requirements for on-site lean-burn generator system would need to be carefully considered in deciding the feasibility of this option. B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Emissions from on-site electric generators would more than off-set the natural gas-fired engines that could be targeted for replacement (e.g., uncontrolled compressor engines or small rich burn pump jack engines). C. Economic: Depends upon economics of ordering electrical motors, the ability of the grid system to supply the needed capacity and the cost to obtain right of way to drop a line to a potential site. Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small. IV. Background data and assumptions used The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff. Gas electrical generator information was obtained from Caterpillar's Website. V. Any uncertainty associated with the option (Low, Medium, High): Medium based upon uncertainties of obtaining electrical easements from landowners and/or land management agencies. VI. Level of agreement within the work group for this mitigation option TBD VII. Cross-over issues to the other source groups (please describe the issue and	
The SUGF agrees that implementation of this federally mandated level of emission control will minimize emissions from newly manufactured, modified and reconstructed engines after their respective effective dates.	Follow EPA New Source Performance Standards (NSPS)

Comment	Mitigation Option
The SUGF supports the control technology options listed above as the SUGF supports usage of Best Available Control Technologies on internal combustion engines located within the exterior boundaries of the Southern Ute Indian Reservation.	Use of SCR for NOx control on lean burn engines Use of NSCR / 3-Way Catalysts and Air/Fuel Ratio Controllers on Rich Burn Stoichiometric Engines Use of Oxidation Catalysts and Air/Fuel Ratio Controllers on Lean Burn Engines Install Lean Burn Engines
As EPA commented on the Cumulative Effects Paper, it is unclear how the 4 Corners Task Force Interim Emissions Recommendations for Stationary RICE are being implemented. The mitigation option Interim Emissions Recommendations for Stationary RICE states that "BLM in New Mexico and Colorado are currently requiring these emission limits as a Condition of Approval (COA) for their Applications for Permits to Drill (APD). These limits currently apply only to new and **relocated** engines ... (compressors assigned to the well APD)..." However, we understand that BLM policy for a small engine COA as applied to an APD is for new and **replacement** engines. The Oil and Gas Workgroup should clarify how is the terms "relocated" and/or "replacement" are being defined by BLM and the USFS with respect to COAs for well located engines. For comparison, EPA's NSPS for spark ignition engines will apply to new, modified, and reconstructed units starting in January 2008. The terms new, modified, and reconstructed are defined in Federal Regulation.	Interim Emissions Recommendations for Stationary RICE
We recommend adding the following next generation technology to the four currently included in this mitigation option: Homogeneous-Charge Compression-Ignition (HCCI) technology was analyzed the by cumulative effects workgroup but was inadvertently omitted from the oil and gas work group mitigation option paper Next Generation RICE Stationary Technology. The following is a recommended text for inclusion in the Final Report: Homogeneous-Charge Compression-Ignition (HCCI) Engine I. Description of the mitigation option Overview Homogeneous charge compression ignition (HCCI) engines are under development at several laboratories. In these engines a fully mixed charge of air and fuel is compressed until the heat of compression ignites it. The HCCI combustion process is unique since it proceeds uniformly throughout the entire cylinder rather than having a discreet high-temperature flame front as is	Next Generation Stationary RICE Control Technologies – Cooperative Technology Partnerships

Comment	Mitigation Option
the case with spark ignition or diesel engines. The low-temperature combustion of HCCI produces extremely low levels of NOx. The challenge of HCCI is in achieving the correct ignition timing, although progress is being made in the laboratories.[1] Only a few experimental measurements of NOx from (HCCI) engines have been reported. The measurements are typically reported as a raw NOx meter measurement in parts per million rather than being converted to grams per horsepower-hour. Dibble reported a baseline measurement of 5 ppm when operated on natural gas.[2] Green reported NOx emissions from HCCI-like (not true HCCI) combustion of 0.25 g/hp-hr.[3] The achievable NOx emission levels are yet to be determined. It is not currently known if HCCI technology can be applied to all engine types and sizes. However, if all reciprocating engines could be converted to HCCI so that the engines produce no more than 0.25 g/hp-hr, then the overall NOx emissions reduction would be 80% in both Colorado and New Mexico using the calculation methodology of the SCR mitigation option. II. Description of how to implement A. Mandatory or voluntary It is too early to determine whether implementation of this technology will be voluntary or mandatory. B. Indicate the most appropriate agencies to implement III. Feasibility of the option A. Technical - HCCI is in the laboratory stage of development. B. Environmental - HCCI has the potential of extremely low NOx levels. C. Economic - HCCI is not sufficiently developed to have proven economic feasibility. IV. Background data and assumptions used 1. Bengt Johansson, "Homogeneous-Charge Compression-Ignition: The Future of IC Engines," Lund Institute of Technology at Lund University, undated manuscript. 2. Robert Dibble, et al, "Landfill Gas Fueled HCCI Demonstration System," CA CEC Grant No: PIR-02-003, Markel Engineering Inc. 3. Johney Green, Jr., "Novel Combustion Regimes for Higher Efficiency and Lower Emissions," Oak Ridge National Laboratory, "Brown Bag" Luncheon Series, December 16, 2002. V. Any uncertainty associated with the option (Low, Medium, or High) HCCI has high uncertainty.	

Comment	Mitigation Option
VI. Level of agreement within the work group for this mitigation option VII. Cross-over issues to the other source groups (Please describe the issue and which group.)	

Oil & Gas Overarching Issues Public Comments

Comment	Mitigation Option
The Four Corners Air Quality Task Force (4CAQTF) is a noble way of beginning communication between our citizenry and the polluting industries. Hopefully some meaningful "common ground" can be reached that will produce measurable air quality improvements. With a demonstrated failure of industry to "want to do their best" and when the "dollar gain" in a corporation's quarterly report is the measuring stick for it's shareholders, the recommendations from the 4CAQTF is up against a mature lobby force very capable of stopping meaningful actions that will lead to measurable benefits to our air quality! Therefore, spending serious time deliberating measurable benefits that could predictably occur if industry's suggestion of "year round" drilling EVERYWHERE as a means of ameliorating their emissions to me, seems without merit. A simple catalytic converter on each of their established fossil fuel operated engines would be considered a "wonderful start" of industry wanting "to do their best". Recommending to any state or federal land wildlife management agency to consider removing established seasonal habitat protection bans for the assumed benefit of distributing annual air quality pollutants should not be an option. Many years were spent by land management and wildlife management agencies formulating the habitats that need protection for identified species. The process to establish habitat closures is elaborate. Let us let this industry recommendation respectfully die and encourage installation of catalytic converters on industry's fossil fuel motors. This action does have measurable air quality results. As we drivers know, we are required by law to have catalytic converters on our vehicles as a way of demonstrating our contribution to improving air quality problems. As a recommendation, I would only suggest that if the oil and gas industry wants to recommend the lifting of this seasonal closure on identified lands, that THEY contact the state and federal agencies that have programming prerogatives over habitat and wildlife issues with their suggestion that lifting this ban would have beneficial measurable benefits for air quality concerns that outweigh wildlife concerns. The 4CAQTF should not be the "quarter back" for carrying the recommendation to state and federal habitat and wildlife agencies. I make these comments as a degreed wildlife biologist with 27 years of experience. Respectfully, Warren J. McNall 900 Sabena, Aztec, NM	Lease and Permit Incentives for Improving Air Quality on Public Lands

Comment	Mitigation Option
Disagree - unlike Wyoming, Colorado has a shortage of state and federal specialists to monitor impacts from oil and gas development. As a result, monitoring of oil and gas impacts to wildlife would likely not happen. Streamlining the permit process would be beneficial to operators economically, but may be at the expense of area wildlife and habitat.	Lease and Permit Incentives for Improving Air Quality on Public Lands
Regarding the paragraph: "Monitoring has also not been a model experience in this area. According to reports of a May, 2006, internal assessment Pinedale, Wyoming, Bureau of Land Management field office, the office neglected its commitment to monitor and limit harm to wildlife and air quality from natural gas drilling in western Wyoming. A wildlife biologist who worked in that Pinedale office, Steve Belinda, is reported to have quit his job because he and other wildlife specialists were required to spend nearly all their time in the office processing drilling requests and were not able to go into the field to monitor the effect of the thousands of wells on wildlife." Basically, I would suggest a more neutral approach than the quoted paragraph. It is rather forceful, without sufficient follow-up. It would help our situation if we could see whether the Farmington office is under similar pressures. Alternatively, examining the policies, rather than experiences, might make for a stronger position. For example, as the author seems to know a bit about BLM and permitting--she/he might instead look into the use of categorical exclusions (CAX) which are currently used to circumvent the environmental assessments (EA) that would normally be required to develop well fields on BLM land. (Sometimes this is also called streamlining.) How prevalent is this practice in the Four Corners, do CAX result in a lower standard of environmental review, and could this practice deleteriously impact 4C air quality?	Lease and Permit Incentives for Improving Air Quality on Public Lands
In light of the current global climate conditions, lessening our overall impact on the environment is everyone's duty to the planet and its children's future. This task force should not be in the position of negotiating away wildlife habitat in exchange for mitigating measures that ought to be a duty of the oil and gas industry as a cost of doing business on this planet.	Lease and Permit Incentives for Improving Air Quality on Public Lands
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Economic-Incentives Based Emission Trading System (EBETS)

Comment	Mitigation Option
Economic-incentives based emission trading systems (EBETS) have had varying levels of success nationally and have been less successful in geographic regions where pollutants are already causing harm to human health or the environment. It can also be argued that these systems lack incentives to improve environmental quality over economics. They can be more a function of market supply and demand driving the trades, not variations in regional human and environmental health "costs". Multisectoral trading systems are complex, increase challenges in emissions monitoring, and environmental justice considerations become more complicated due to inequitable concentrations of source emissions and different pollutant mixing outcomes. (Regarding the federal Acid Rain Program, indeed, the nationwide level of emissions from electric utilities were halved since 1980, however, no geographic restrictions were imposed and many areas of higher pollution levels remained at higher levels.) As stated in the Task Force document, the major burden for the EBETS mitigation option would be administrative; however the full burden must be assessed and coordinated among the state agencies. Not only would comparability and tracking of different types, sizes and ages of installations be extremely complicated, multi-pollutant emissions trading is challenging to monitor and enforce. Although it would be impossible to have an emissions trading system that eliminates environmental injustice, a carefully designed trading system that is rigorous, far-sighted, and includes geographic restrictions would have a much better chance of reducing localized injustices to human health and/or the environment.	Economic-Incentives Based Emission Trading System (EBETS)
The proposed incentive to modify standard stipulations for federal land if it is to be the relaxing or waiving of seasonal restrictions for wildlife while promoting year round drilling should not be a part of the voluntary program. Seasonal restrictions have been written to benefit wildlife during times of the year when they are at increased risk due to weather, nesting, birthing, etc. The Wyoming experience has shown the potential negative impacts of intense drilling on wildlife, and how highly wildlife is valued by a broad range of American people. With the pressures from the increase in drilling, wells, roads, and pipelines in the Four Corners area, we can ill afford to lose the wildlife protections from the stipulations that we currently have.	Voluntary Programs
New Mexico and Colorado already have rules governing H2S, no need to add more rules that may conflict.	Mitigation of Hydrogen Sulfide
New Mexico Environment Department does have controls for H2S on paper, but state environmental officials have validated that the state does not have H2S monitoring equipment.	Mitigation of Hydrogen Sulfide
Mitigation option is both economically feasible and environmentally beneficial, as a result we strongly agree with their implementation.	Mitigation of Hydrogen Sulfide
Rules that are capable of being enforced due to adequate staffing and necessary monitoring tools are what is needed to regulate this area. More rules that cloud the issue, or are effectively toothless due to lack of enforcement infrastructure will not accomplish the goals of this task force.	Mitigation of Hydrogen Sulfide

Power Plants

Power Plants: Preface

Overview

The Power Plants Work Group was charged with developing mitigation strategies for existing, proposed, and future power plants in the Four Corners area. For each strategy, one or more work group members provided a basic description of the strategy, ideas for implementation, and discussed feasibility issues to the extent possible.

Participation in the Power Plants Work Group included representatives from state, tribal and federal agencies; industry (including regional power plants); citizens; and interest groups. Ten to 20 participants attended each face-to-face meeting throughout the process. In total, the Power Plant Work Group brainstormed a total of 36 mitigation options and drafted 34. In addition, work group members helped in drafting 18 mitigation options for the Energy Efficiency, Renewable Energy and Conservation section.

Organization

The Power Plants work group initially collected information on existing emissions inventories and emissions projections for existing and proposed power plants. A spreadsheet, called Four Corners Area Power Plants Facility Data Table**,** is located at the end of the Power Plants section and was used as a tool to help supplement mitigation options papers with emissions reduction estimates. The work group divided the remainder of its work into the following categories.

Existing Power Plants: The work group first considered existing power plants, focusing on the two largest power plants in San Juan County: San Juan Generating Station (1800 MW) and Four Corners Power Plant (2000 MW). Eleven mitigation options were brainstormed and drafted for this section. The options drafted ranged from software applications and process optimization to retrofitting NOx and SO_2 emissions control technologies.

Proposed Power Plants: The work group next considered the proposed power plants category. The focus here was on the proposed Desert Rock Energy Project, a 1500 MW coal-fired power plant to be built in Burnham, 30 miles Southwest of Farmington. Options included funding of air quality improvement initiatives and consideration of the Integrated Gasification Combined Cycle (IGCC) process. Four of the 11 comments received on the Power Plants section of the Task Force Report during the public comment process were against building another power plant in the Four Corners area. Desert Rock also submitted comments on the Task Force report. Please see all the public comments pertaining to power plants in an appendix at the end of this section.

Future Power Plants: The work group discussed and documented eight strategies that future power plants could use to mitigate air pollution, including a carbon capture and sequestration (CCS) option, an option for clean coal incentives, large scale renewable energy production, and also an option on nuclear energy production.

Overarching Issues: Finally, the Power Plants report section also has an overarching category for options and ideas that may apply more broadly. Ten options were brainstormed and drafted here, and include mercury pollution mitigation and the Clean Air Mercury Rule (CAMR), cap and trade programs, greenhouse gas mitigation and one calling for a health study.

EXISTING POWER PLANTS: ADVANCED SOFTWARE APPLICATIONS

Mitigation Option: Lowering Air Emissions by Advanced Software Applications: Neural Net

I. Description of the mitigation option

There are many areas of power plant operation where Advanced Software Applications could lower air emissions from current levels. These processes range from the primary power generation equipment, to the various air pollution control devices (APCDs), such as scrubbers, precipitators, baghouses, and SCR units. The best gains in emission reduction couple state-of-the-art APCDs with advanced software applications operating within or in concert with the Distributed Control System, DCS. This mitigation option discusses Neural Network software to lower NO_x emissions at coal combustion low-NO_x burners. Other examples may be found in the Appendix.

Many power plant processes/devices, such as fan speeds, air damper positions, air and coal flows, are automatically controlled by the DCS. The DCS is a networked computer system with "distributed" input/output electronic hardware near the plant control devices, and "live" displays for the control room operators. Given the current state (on/off status or analog value) of every device tag in its database, the DCS uses feedback control algorithms to drive many controlled device variables. Set-points are optimized for the current desired mode of plant operation, such as satisfying a specified megawatt demand at the best possible heat rate.

Neural Networks offer advanced software control by "training" the software to "know" where outputs should be in relation to many inputs. Unlike traditional mathematical equation models, neural networks do not demand intimate understanding of the process. A neural network, sometimes referred to as "fuzzy logic," is a type of "artificial intelligence" statistical computer program, which classifies large and complex data sets by grouping cases together in a manner similar to the human brain. Neural networks "learn" complex processes by analyzing their performance data.

San Juan Generation Station (SJGS) is currently working with a predictive neural network on Units 1 and 2 to lower NO_x emissions. This advanced software application, provided by the DCS vendor, minimizes NO_x formation by optimizing air flow to the burners (e.g., optimal flame temperature). SJGS is gaining experience with this type of software, anticipating the installation of state-of-the-art low-NO_x burner hardware. When these burners are installed on all units, increased reductions in NO_x are anticipated. Neural network software results in lower NO_x emissions than if the burners were controlled by standard DCS software alone.

The neural network uses inputs from the NO_x and O_2 CEMS, Carbon Monoxide (CO) emissions, burner air, secondary combustion air, coal flow, flame temperature, fan speeds, damper positions, etc. There could be dozens of inputs. The network is trained to identify the relative contribution of each process input to NO_x formation as measured by the CEMS. The network is trained across varying modes of plant operation – full load, partial load, startup, etc. at the lowest possible NO_x emissions. Then, as the generating unit operates in various modes, the neural network predictions refine the control actions the DCS would take on its own. This refinement lowered NO_x emissions by approximately 25% at an Entergy coal fired plant (Intech, July 2006 – "Netting a Model Predictive Combo").
Note: CO_2 readings do not correlate significantly to NO_x control. Inputs from the NO_x, CO, and O_2 CEMS are used.

Benefits: NO_x reductions of 10% – 30%. Earn NOx Trading Credits as future regulations may require. Another important benefit is that tighter process controls from the neural network may improve the plant heat rate. When the heat rate improves, less energy is needed to maintain required MW load. With less associated stack gas volume for that load, all pollutant emissions decrease.

Trade-offs: Neural network cannot adapt to unforeseen upsets for which it was not originally trained. Neural net refinement control may have to be removed in these situations.

Some existing boiler controls may need to be automated so the neural network can act on them via the DCS. There are significant associated hardware, software, and labor costs. In combustion control schemes, optimizing NO_x for lowest emissions generally increases CO. CO emissions might increase because the neural network allows CO to ride very close to its regulatory limit. Without the network, CO is manually controlled to a lower level providing a cushion for upsets.

Software is processor-intensive.

Burdens: Cost of software application, more powerful computer hardware, "training" labor. Cost of upgrading some of the other controls on the boiler. The neural net is not much good unless it can actually adjust the equipment such as dampers, burner air registers, fan speed, etc. The controls have to be automated and have to be compatible with the neural net.

II. Description of how to implement

A. Mandatory or voluntary:
This option is being considered by San Juan Generating Station as part of consent decree to reduce NO_x emissions. It may be a viable option for FCPP. There may be some grants available to help fund such upgrades to existing power plants in Four Corners area.

FCPP has also installed neural networks and is gaining experience with process and emissions optimization. Desert Rock's potential use of this option is unknown.

B. Indicate the most appropriate agency(ies) to implement:
Federal, State, Tribal regulations should not specify specific control strategies, but rather impose emission limits reasonable for modern control strategies. Grandfathering of plants under NSR for installing enhanced controls, is another debate. However, if Federal NO_x budget trading is extended to this area under a Clear Skies option, the economic incentive of expensive NO_x trading credits to either buy or sell would encourage the final emissions control step of "advanced software applications" to realize optimum economic and environmental benefits.

Differing Opinion: Using NOx Budget trading and other grand fathering strategies do not address the pollution problems associated with old, out of date coal fired power plants. The Four Corners Power Plant is the top emitter of NOx in the Nation. Two coal fired power plants with high levels of emissions are located in the Four Corners. Grand fathering should not be an option. Extensive emissions clean up and control is necessary.

III. Feasibility of the option

A. Technical: Neural network technology is a viable control approach well established in many industrial process settings, but requires intensive computational capability. Powerful, cost-effective computers of recent years have facilitated growth of this technology. Due to some limitations to this control strategy, it takes its place with other advanced control strategies, such as Model Predictive Control.

B. Environmental: Environmental impacts are incidental, such as increased power consumption for more powerful computer hardware.
The point of this option is more efficient operation and thus lower emissions.

C. Economic: Software costs and labor are reasonable in light of the long term emission reductions attained. Generally, software costs are much less than capital expenditures for physical APCDs.

The Monitoring Work group asked if additional CEM or other technology be required to operate as part of the neural net feedback loop. SJGS and FCPP have existing NO_x CEMS to meet state and federal Acid Rain Program monitoring requirements. Acid Rain requires a high level of data quality assurance, including daily calibrations. A neural network continues to function upon loss of one or more inputs, within statistical limits. NO_x minimization control would continue during occasional loss of the NO_x CEMS input.

IV. Background data and assumptions used:
ISA Intech article
Information from San Juan Generating Station
There are many other sources of relevant information, including AWMA, Argonne, DOE.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups
Advanced Software Applications, including neural network control technology, could apply to sources in the Oil and Gas sector

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EXISTING: BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

Mitigation Option: Control Technology Options for Four Corners Power Plant

I. Description of the mitigation option

Summary of Option

Presumptive Best Available Retrofit Technology (BART) emission limits for SO_2 should be applied to all units at Four Corners Power Plant (FCPP). Presumptive BART emission limits for NO_x should be applied to Units 1, 2 and 3; and combustion controls and Selective Catalytic Reduction (SCR) on Units 4 and 5. When BART for PM10 at FCPP is analyzed, the regulatory authority and the facility should consider the control level achieved at San Juan Generating Station.

Background: Best Available Retrofit Technology (BART)

The Four Corners Power Plant consists of five pulverized coal fired boilers. Each boiler was built between 1962 and 1977 and emits more that 250 tons per year of visibility-impairing pollution. The units are therefore subject to the Best Available Retrofit Technology (BART) requirements under the Regional Haze Rule. The BART requirements mandate industrial facilities that cause or contribute to regional haze to control emissions of visibility-impairing pollutants. The Clean Air Act (CAA) states that BART guidelines shall apply to fossil-fueled fired generating power plants with a capacity greater than 750 MW (§169A(b)). The CAA does not exempt individual units of any size from BART requirements.

For Electric Generating Units with a capacity greater than 200 MW, the Environmental Protection Agency (EPA) has provided (rebuttable) presumptive emission limits for sulfur dioxide (SO_2) and nitrogen oxides (NO_x), based on boiler size, coal type and controls already in place. EPA "analysis indicates that these controls are likely to be among the most cost-effective controls available for any source subject to BART, and that they are likely to result in a significant degree of visibility improvement." (70 FR 39131, July 6, 2005). Because the two smaller units (#1 & #2, each at 190 gross MW) are subject to BART and are close in capacity to EPA's 200 MW threshold, the rationale for applying presumptive limits should hold for those units as well. Those presumptive limits (which are 30-day rolling averages) are:

- Unit #1 is 190 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #2 is 190 gross MW dry bottom wall -fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #3 is 253 gross MW dry bottom wall -fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #4 is 818 gross MW cell-burner: 0.15 lb SO_2/mmBtu and 0.45 lb NO_x/mmBtu
- Unit #5 is 818 gross MW cell-burner: 0.15 lb SO_2/mmBtu and 0.45 lb NO_x/mmBtu

Background: FCPP Emissions

In the 1980s, Arizona Public Service (APS) installed venturi scrubbers on Units 1-3, and early generation spray tower scrubbers—but with significant stack gas bypass—on Units 4 and 5. In 2003, APS began a program to further reduce SO_2 emissions at FCPP by eliminating most stack gas bypass. APS succeeded in bringing emissions down from a 30-day rolling plant wide average of 0.44 lb/mmBtu in 2003 to 0.16 lb/mmBtu by 2005, with further improvement to 0.14 lb/mmBtu; this represents a removal efficiency of 92 percent. Although NO_x and PM_{10} emissions were not addressed in that effort, NO_x emissions have been reduced slightly, but FCPP is still the largest emitter of NO_x among coal-fired power plants nationwide.[1] The current rate at which FCPP emits NO_x is approximately 0.54 lb/mmBtu.

The FCPP is located on the Navajo Reservation, and was previously regulated by emission limitations set by the State of New Mexico. The Tribal Authority Rule, however, generally stated that state air quality regulations could not be enforced against facilities on the Indian reservation. EPA, therefore, has to issue federally enforceable emission limitations for FCPP. On August 31, 2006 EPA Region 9 proposed a Federal Implementation Plan (FIP) to establish federally enforceable emission limits for SO_2, NO_x, total PM, and opacity. The proposed FIP would require 88 percent removal of plant wide SO_2[2] on an annual rolling average basis. This would result in plant wide annual average SO_2 emissions being limited to 0.24 lb/mmBtu on coal projected to be burned in 2016.[3] The proposed FIP would require NO_x emissions not to exceed 0.85 lbs/mmBtu for Units 1 and 2, and 0.65 lbs/mmBtu for Units 3, 4 and 5.

The Four Corners Power Plant is located on the Navajo Reservation and the Tribal Authority Rule has stated that state air quality regulations could not be enforced against facilities on the Indian Reservation. It is imperative that a firm agreement between the Navajo Tribe and the Federal EPA be negotiated to guarantee that the Federal EPA will be the regulatory and enforcement agency for the Four Corners Power Plant (FCPP) clean up process. This will allow the Federal EPA to regulate and enforce emission limits for SO2, NOx, PMs and opacity that are specified in the new EPA Region 9 FIP.

Update: On April 30, 2007, EPA Region 9 finalized a Federal Implementation Plan (FIP) that establishes federally enforceable emission limits for SO_2, NO_x, total PM_{10} and opacity. The FIP requires 88 percent removal of plant wide SO_2 on an annual rolling average basis, and limits three-hour average SO_2 emissions to 17,900 lbs/hr plant wide. This would result in plant wide annual average SO_2 emissions being limited to 0.24 lb/mmBtu on coal projected to be burned in 2016. The FIP requires that 30-day rolling average NO_x emissions are not to exceed 0.85 lbs/mmBtu for Units 1 and 2, and 0.65 lbs/mmBtu for Units 3, 4 and 5; and daily NO_x emissions are not to exceed 335,000 lbs. PM emissions are limited to 0.050 lbs/mmBtu, and opacity is limited to 20%, except for one six-minute period per hour not to exceed 27%.

Presumptive BART at FCPP

Sulfur Dioxide

The application of presumptive BART limits for SO_2 on Units 1-5 at FCPP would result in a plant wide annual average of 0.15 lbs/mmBtu or 93 percent removal based on future coal. Estimated emissions for 2018[4] are shown in Figures 2 & 3 for emissions at the current level of control, the proposed level of control under the FIP, a scenario with BART applied to Units 3-5 only, and BART applied to Units 1-5. All options assume control efficiency remain constant within each given scenario.

Emissions under the scenario where presumptive BART for SO_2 is applied to all Units are only slightly less than current emission rates. However, applying presumptive BART for SO_2 would result in an emission limit specified as an allowable rate of emissions (lbs/mmBtu). The FIP would allow SO_2 removal to decline from the present 92 percent to 88 percent. Additionally, the FIP specifies the SO_2 limit in terms of efficiency, or percent removal of SO_2 from the coal being burned. If the coal quality decreases (to higher sulfur coal), as it is projected to do, the limit in terms of percent removal will allow for more emissions of SO_2; thus, it is preferable to have an emission rate as the controlling limit.

Nitrogen Oxides

The application of presumptive BART limits for NO_x on Units 1-3 (0.23 lb/mmBtu), and combustion controls and SCR on Units 4 & 5 would result in a plant wide annual average of 0.16 lb/mmBtu. Application of presumptive BART for Units 4 & 5 would result in a rate of 0.45 lbs/mmBtu for those Units. Estimated emissions for 2018 are shown in Figure 4 for emissions at the current level of control, the current Title V permit limit, the proposed level under the FIP, a scenario with BART applied to Units 1-5, and a scenario that applies BART to Units 1-3 and applies combustion controls and SCR to Units 4 & 5. NO_x emissions under the proposed FIP would be significantly higher than current rates; application of presumptive BART for NO_x to all Units would reduce NO_x 30 percent from current rates; application of presumptive BART to Units 1-3, and combustion controls plus SCR on Units 4 & 5 would result in the most significant reductions of NO_x: 70 percent from current rates, and less than half from the scenario with BART on all Units.

Since Units 4 and 5 are cell burners, they are inherently very high emitters of NO_x, and, because of the narrowness of their furnaces, are very difficult to reduce emissions by combustion controls alone (combustion controls alone represent presumptive BART). EPA has recognized that the presumptive limits (and associated technologies) do not preclude the application of different technologies: "[b]ecause of differences in individual boilers, however, there may be situations where the use of such controls would not be technically feasible and/or cost-effective. . . . Our presumption accordingly may not be appropriate for all sources."[5] The cost (see below) of SCR on these Units is comparable to combustion controls—which may not be technically feasible—and SCR will result in significantly more reductions of NO_x. Currently, Units 4 and 5 each emit twice the NO_x as Units 1, 2 and 3 individually.[6] Therefore, SCR is the best reasonable method to achieve meaningful NO_x reductions at Units 4 and 5.

Reduction of NO_x is particularly important to improve visibility at Mesa Verde National Park, which is 52 km away from FCPP. As shown in Figures 1a, 1b and 1c, visibility has degraded at Mesa Verde over the past decade, and the portion of degradation due to nitrate has increased (while there has been no trend in degradation due to sulfate).

<u>II. Description of how to implement</u>

<u>A. Mandatory or voluntary:</u>

This option represents a mandatory, federally enforceable emission limit.

<u>B. Indicate the most appropriate agency(ies) to implement:</u>

The regulating agency for this facility is EPA Region 9.

<u>III. Feasibility of the option</u>

FCPP is currently at or below the presumptive BART limit for SO_2. No additional controls are needed.
Differing Opinion: FCPP does not consistently operate at or below presumptive BART limit for SO_2

For Units 1-3, the Environmental Protection Agency's suggested presumptive BART for NO_x limits "reflect highly cost-effective technologies."[7] EPA, in fact, performed visibility impact and cost-effectiveness analyses on the presumptive limits. Therefore, the BART presumptive limits of NO_x are considered to be technical and economically feasible.

EPA states that the majority of units could meet presumptive NO_x limits with current combustion control technology for between $100 and $1000 per ton of NO_x removed. If more advanced combustion controls are required, the cost would be less than $1500 per ton of NO_x removed. Furthermore, EPA states that "by the time units are required to comply with any BART requirements . . . more refinements in combustion control technologies will likely have been developed by that time. As a result, we believe our analysis and conclusions regarding NO_x limits are conservative.[8]

Application of EPA's Cost Tool model for Units 4 & 5 predicts that NO_x could be reduced by 70% to the levels shown by application of combustion controls plus SCR at a cost of $409 - $464 per ton of NO_x removed.[9] EPA states that the average cost of combustion controls on cell burners (presumptive BART) is $1021 per ton. The average cost of applying SCR to cyclone units, (which for those units is presumptive BART), is $900 per ton.

<u>IV. Background data and assumptions used</u>

Historical emissions data comes from EPA's Clean Air Markets Division databases. Projected capacity utilizations come from the Western Regional Air Partnership's "11_state_EGU_analysis" projections.

EPA's cost tool: http://www.epa.gov/airmarkt/arp/nox/controltech.html

V. Any uncertainty associated with the option

Uncertainties in FCPP's ability to meet the BART presumptive limit for SO_2 include future coal quality. Future emissions of SO_2, NO_x and PM10 will depend on future utilization, which at this point has been predicted.

VI. Level of agreement within the work group for this mitigation option To Be Determined.

VII. Cross-over issues to the other Task Force work groups None.

Citations:

[1] http://cfpub.epa.gov/gdm/index.cfm?fuseaction=factstrends.top_bypollutant
[2] Although EPA limits annual average SO_2 emissions to 12.0% of the SO_2 produced by the plant's coal-burning equipment, its method of calculating the amount of SO_2 produced is not consistent with EPA's "Compilation of Air Pollutant Emission Factors," (AP-42) which assumes that 12.5% of the sulfur in sub-bituminous coal (as burned at FCPP) is never converted to SO_2 but is retained in the ash collected in the boiler. When this sulfur retention is taken into consideration, the EPA proposal represents 86% control of potential SO_2 emissions.
[3] BHP, the supplier of coal to FCPP, has projected coal quality to 2016 when its contract expires. This estimate is based upon 2016 coal with a heating value of 8,890 Btu/lb and a sulfur content of 0.85%. (document prepared by C. Nelson, BHP Navajo Coal Company on 27 February 2006 and submitted by Sithe Global as part of the Desert Rock permit application).
[4] All projections are based upon fuel quality estimates from the coal supplier and WRAP utilization growth projections.
[5] 70 F.R. 39134 (July 6, 2005).
[6] http://www.epa.gov/airmarkets/emissions/prelimarp/05q4/054_nm.txt
[7] 70 F.R. 39131, July 6, 2005.
[8] 70 F.R. 39135, July 6, 2005.
[9] http://www.epa.gov/airmarkt/arp/nox/controltech.html

Figure 1.a. WRAP Total Extinction Trends

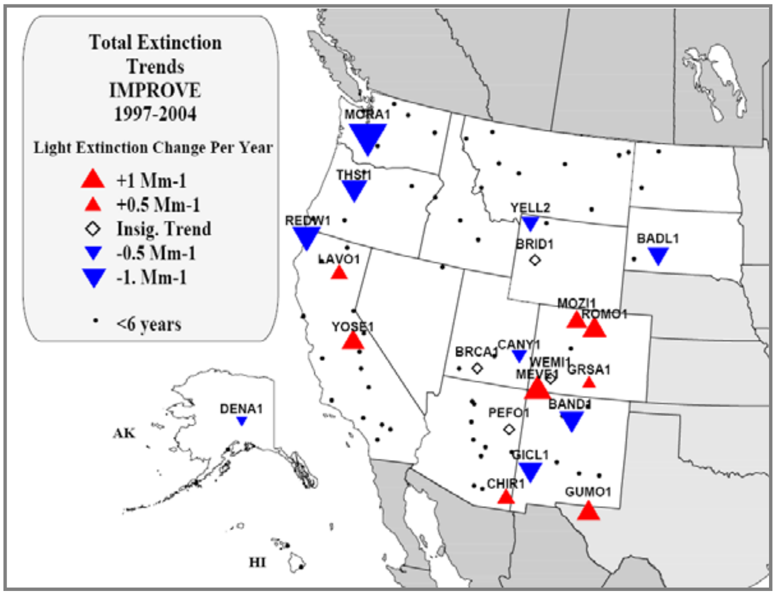


Figure 1.b. WRAP Sulfate Extinction Trends

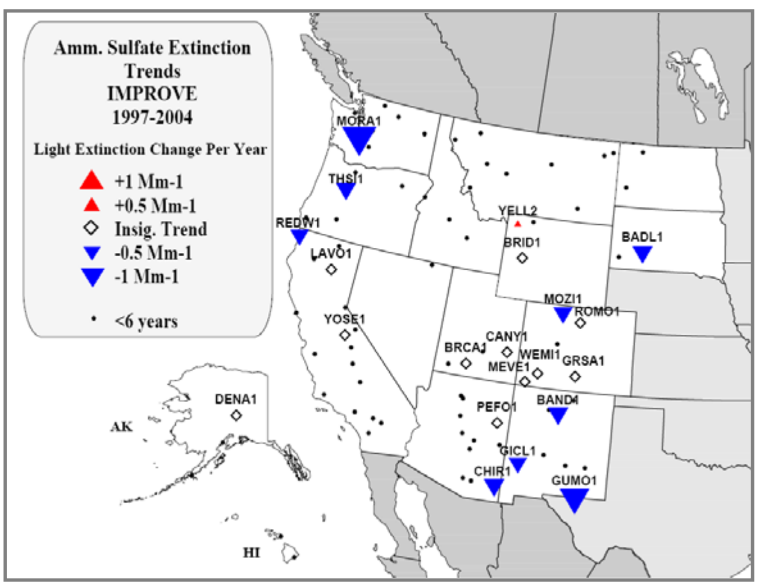


Figure 1.c. WRAP Nitrate Extinction Trends

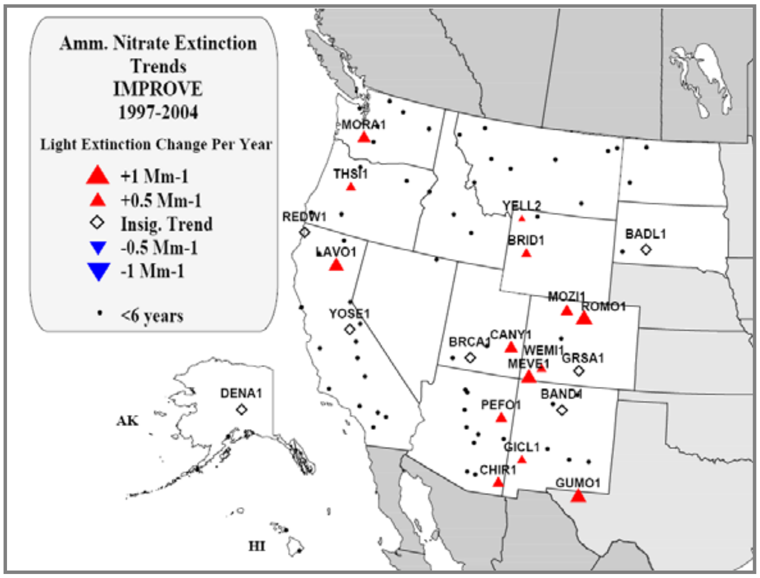


Figure 2. FCPP Emission Trends

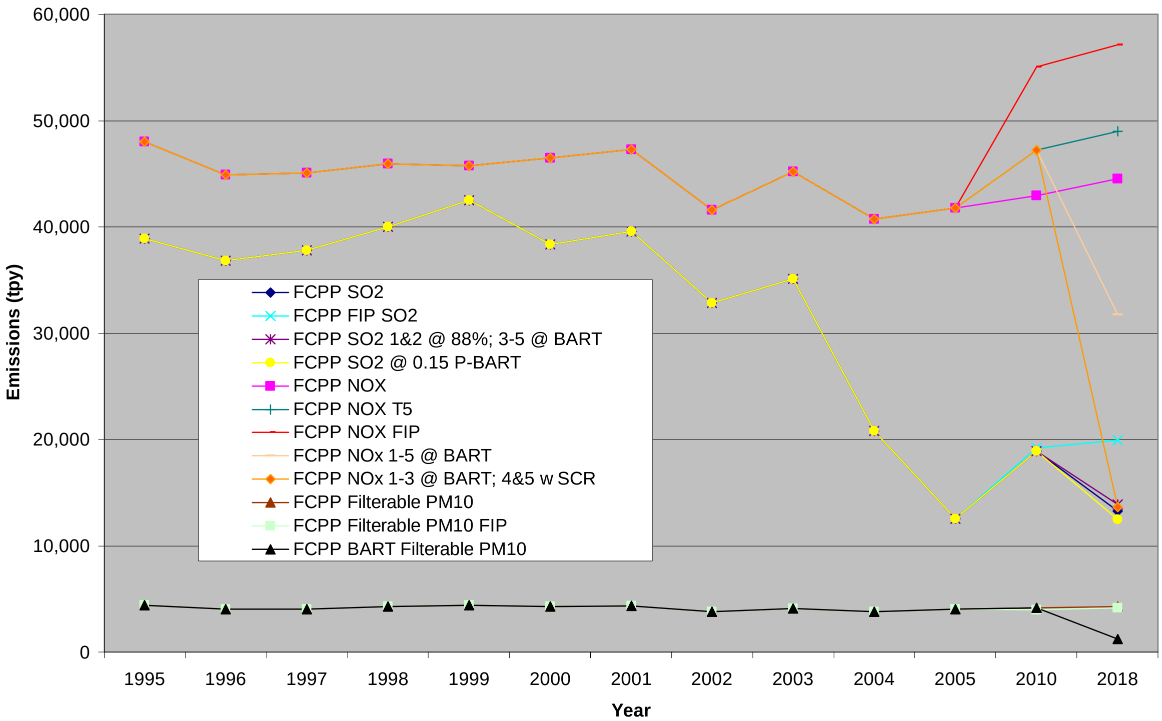
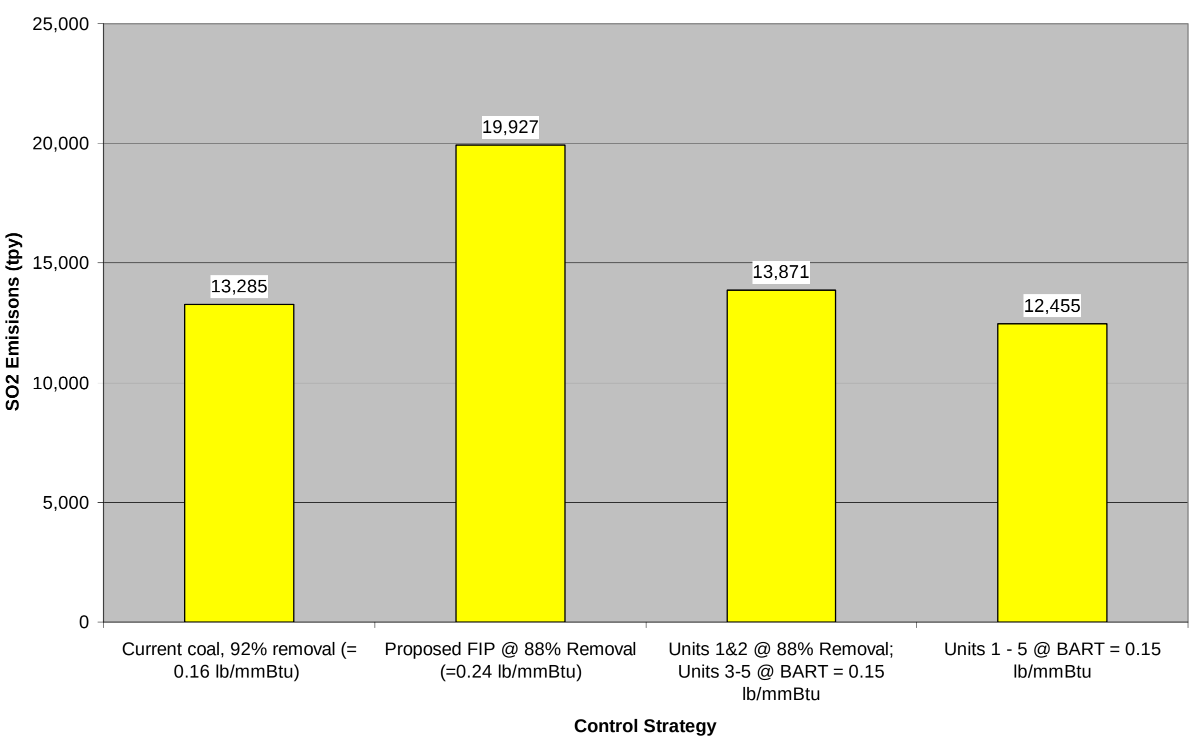


Figure 3. FCPP 2018 SO2 vs. Control Strategy



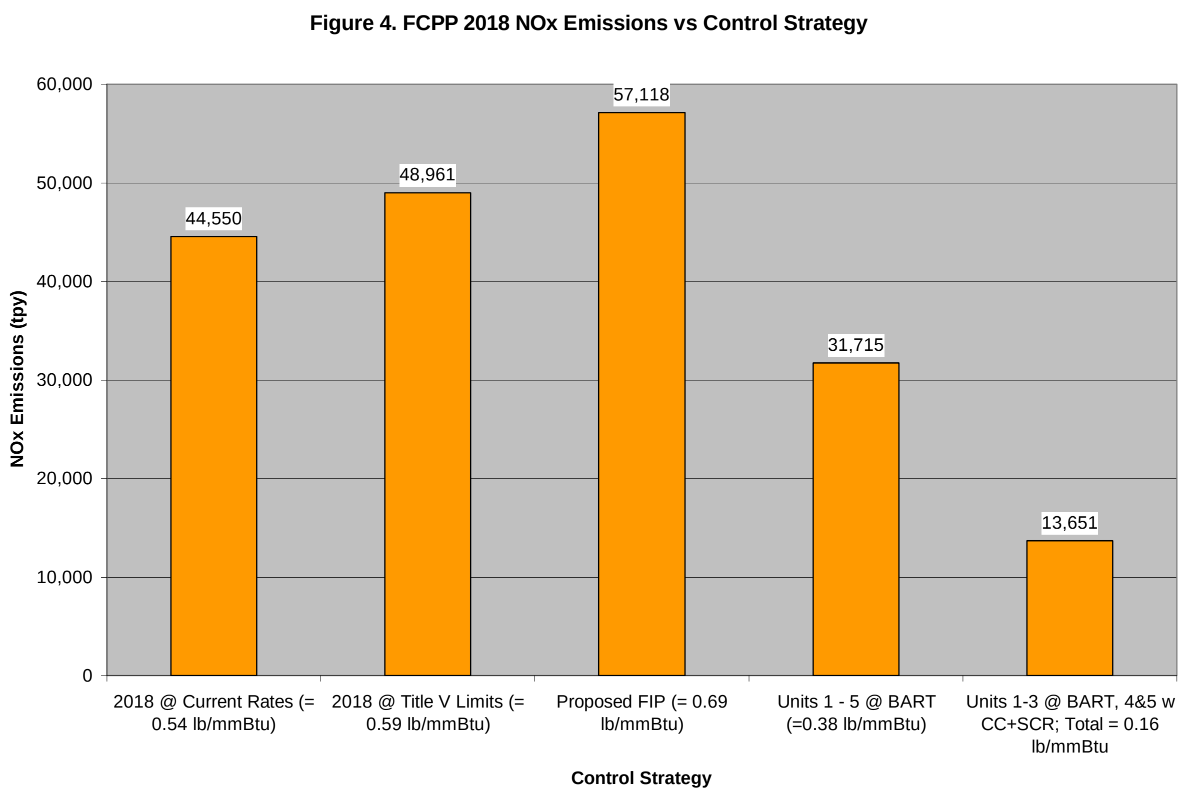


Figure 4. FCPP 2018 NOx Emissions vs Control Strategy
NOx Emissions (tpy)
60,000
50,000
40,000
30,000
20,000
10,000
0
44,550
48,961
57,118
31,715
13,651
2018 @ Current Rates (= 0.54 lb/mmBtu)
2018 @ Title V Limits (= 0.59 lb/mmBtu)
Proposed FIP (= 0.69 lb/mmBtu)
Units 1 - 5 @ BART (=0.38 lb/mmBtu)
Units 1-3 @ BART, 4&5 w CC+SCR; Total = 0.16 lb/mmBtu
Control Strategy

Mitigation Option: Control Technology Options for San Juan Generating Station

I. Description of the mitigation option

Summary of Option

Presumptive emission limits for NO_x should be applied to all units at San Juan Generating Station (SJGS).

Background: Best Available Retrofit Technology (BART)

SGJS consists of four pulverized coal fired boilers. Each boiler was built between 1962 and 1977 and emits more that 250 tons per year of visibility-impairing pollution. The units are therefore subject to the Best Available Retrofit Technology (BART) requirements under the Regional Haze Rule. The BART requirements mandate industrial facilities that cause or contribute to regional haze to control emissions of visibility-impairing pollutants. The Clean Air Act (CAA) states that BART guidelines shall apply to fossil-fueled fired generating power plants with a capacity greater than 750 MW (§169A(b)). The CAA does not exempt individual units of any size from BART requirements.

For Electric Generating Units with a capacity greater than 200 MW, the Environmental Protection Agency (EPA) has provided (rebuttable) presumptive emission limits for sulfur dioxide (SO_2) and nitrogen oxides (NO_x), based on boiler size, coal type and controls already in place. EPA "analysis indicates that these controls are likely to be among the most cost-effective controls available for any source subject to BART, and that they are likely to result in a significant degree of visibility improvement." (70 FR 39131, July 6, 2005). Those presumptive limits (which are 30-day rolling averages) are:

- Unit #1 is 359 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #2 is 359 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #3 is 555 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu
- Unit #4 is 555 gross MW dry bottom wall-fired: 0.15 lb SO_2/mmBtu and 0.23 lb NO_x/mmBtu

Background: SJGS Emissions

In March of 2005, Public Service of New Mexico (PSNM) entered into a Consent Decree to reduce SO_2, NO_x, and PM_{10} emissions by 2010 at SGJS to the levels shown below:

- NO_x = 0.30 lb/mmBtu (30-day rolling average). The Consent Decree requires that San Juan minimize NOx emissions. The 0.30 lb/mmBtu limit will be evaluated after 1 year of operation and adjusted to a lower limit if possible.
- SO_2 = 90% annual average control,[1] not to exceed 0.250 lb/mmBtu for a seven-day block average.
- PM_{10} = 0.015 lb/mmBtu (filterable)

PSNM will replace all four existing Electrostatic Precipitators with Fabric Filters. San Juan currently meets the 0.015 lb/mmBtu limit with the existing Electrostatic Precipitators. The fabric filters (baghouses) will be installed primarily to reduce opacity spikes during upset conditions and to allow the addition of activated carbon for mercury control.

PSNM will have to meet the 90% SO_2 control requirement regardless of the coal quality. Current coal quality averages about 1.4 lb SO_2/mmBtu (uncontrolled). Therefore, ninety percent control would result in an annual average emission rate of 0.14 lb/mmBtu, and would likely satisfy the presumptive BART requirement.

Presumptive BART for NO_x at SJGS

The Consent Decree (CD) level for NO_x is 0.30 lb/mmBtu; the BART presumptive level for NOx is 0.23 lb NO_x/mmBtu. The BART presumptive level is lower than that in the CD, and therefore will result in lower emissions. Figure 1 depicts the historical trends of SO_2 and NO_x at SJGS, as well as future trends out to 2018 based upon available information on coal quality[2] and capacity utilization.[3] Emission increases after 2010 are due to increased utilization. The decreased NO_x emissions are based on the assumption that SJGS Units 1-4 will meet the presumptive BART limit for NO_x by 2018.

The presumptive BART level of 0.23 lbs/mmBtu was developed based on Powder River Basin (PRB) Coal. Although both the PRB and the San Juan Basin coals are considered sub bituminous, San Juan coal has properties of bituminous coal which has a higher presumptive BART level.

Reduction of NO_x is particularly important to improve visibility at Mesa Verde National Park, which is 43 km away from SJGS. As shown in Figures 1a, 1b and 1c, visibility has degraded at Mesa Verde over the past decade, and the portion of degradation due to nitrate has increased (while there has been no trend in degradation due to sulfate).

II. Description of how to implement

A. Mandatory or voluntary:

This option represents a mandatory, federally enforceable emission limit.

B. Indicate the most appropriate agency(ies) to implement:

The regulating agency for this facility is the State of New Mexico.

III. Feasibility of the option

The Environmental Protection Agency's suggested presumptive BART limits "reflect highly cost-effective technologies."[4] EPA, in fact, performed visibility impact and cost-effectiveness analyses on the presumptive limits. Therefore, the BART presumptive limits of NO_x are considered to be technical and economically feasible.

EPA states that the majority of units could meet these NO_x limits with current combustion control technology for between $100 and $1000 per ton of NO_x removed. If more advanced combustion controls are required, the cost would be less than $1500 per ton of NO_x removed. Furthermore, EPA states that "by the time units are required to comply with any BART requirements . . . more refinements in combustion control technologies will likely have been developed by that time. As a result, we believe our analysis and conclusions regarding NO_x limits are conservative.[5]

The most accurate cost estimate for SJGS to meet the BART limit for NO_x is likely to be from EPA's Cost Tool model, which estimates costs for specific units at specific emission rates.[6] That model predicts that the presumptive BART limits for NO_x could be met at costs of $355 - $501 per ton.

San Juan is currently in the process of doing a BART Analysis. It will be submitted to the NMED in June 2007.

IV. Background data and assumptions used

Historical emissions data comes from EPA's Clean Air Markets Division databases. Projected capacity utilizations come from the Western Regional Air Partnership's "11 State EGU Analysis" projections.
EPA's Cost Tool Model: http://www.epa.gov/airmarkt/arp/nox/controltech.html

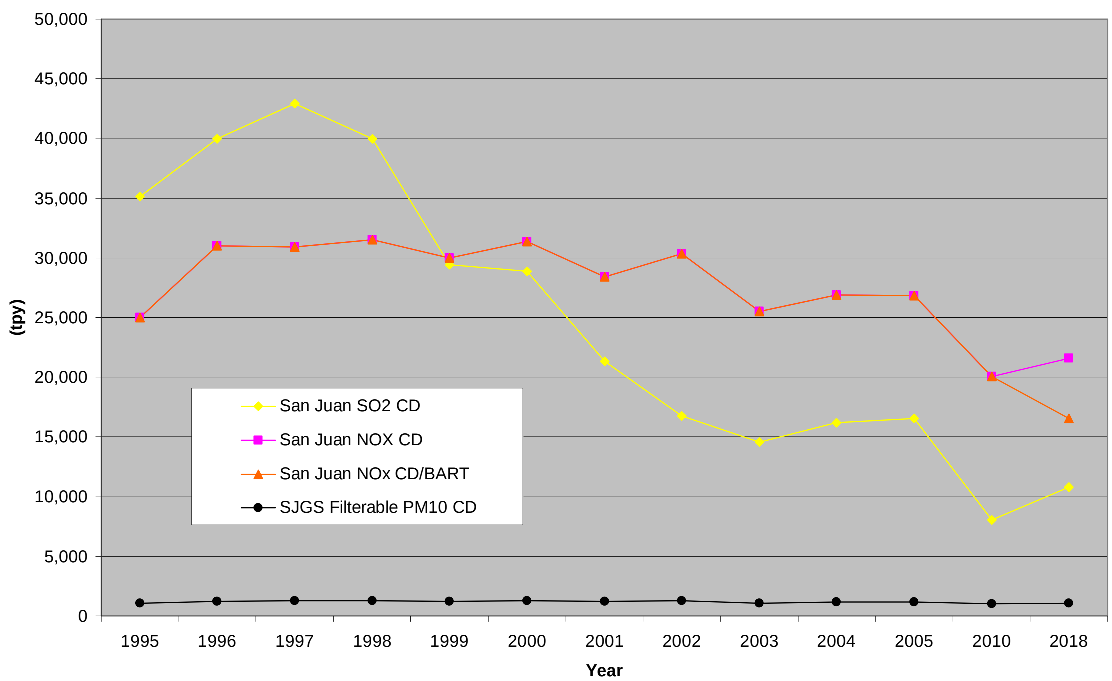
V. Any uncertainty associated with the option (Low, Medium, High)
Uncertainties in SJGS's ability to meet the BART presumptive limit for SO2 include future coal quality. Future emissions of SO_2, NO_x and PM10 will depend on future utilization, which at this point has been predicted.

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups None.

Citations:
[1] Based upon scrubber inlet and outlet SO_2 concentrations, as measured by Continuous Emission Monitors.
[2] Document prepared by C. Nelson, BHP Navajo Coal Company on Feb. 27, 2006 and submitted by Sithe Global as part of the Desert Rock permit application.
[3] Western Regional Air Partnership, 11 State EGU Analysis spreadsheet
[4] 70 F.R. 39131, July 6, 2005.
[5] 70 F.R. 39135, July 6, 2005.
[6] http://www.epa.gov/airmarkt/arp/nox/controltech.html

Figure 1. San Juan SO2 & NOx



EXISTING: OPTIMIZATION

Mitigation Option: Energy Efficiency Improvements

I. Description of the mitigation option
Upgrades or major repairs to existing power plants are potentially subject to the New Source Review process. This includes projects that are undertaken to improve the efficiency of the plants (i.e., produce more power while burning less or the same amount of fuel.) This process has been so difficult and cumbersome that these projects are often not cost-effective to pursue. The regulatory agencies should work closely with the utilities to simplify the process, remove barriers and to encourage these efficiency improvements.

II. Description of how to implement
A. Mandatory or voluntary:

B. Indicate the most appropriate agency(ies) to implement
Regulating agencies:
EPA Region 9 Air Programs, Navajo Nation EPA, New Mexico Air Quality Bureau

III. Feasibility of the option
A. Technical:
B. Environmental:
C. Economic:

IV. Background data and assumptions used:

V. Any uncertainty associated with the option (Low, Medium, High):
Medium

VI. Level of agreement within the work group for this mitigation option.
TBD

VII. Cross-over issues to the other Task Force work groups:
None

Mitigation Option: Enhanced SO_2 Scrubbing

I. Description of the mitigation option

Enhanced SO_2 scrubbing on existing power plants in the Four Corners area has resulted in significant SO_2 reductions. This mitigation option suggests further efforts to develop and optimize SO_2 scrubbing at San Juan Generating Station and Four Corners Power Plant.

Background:
Wet Flue-Gas Desulfurization System:
Wet scrubbing, or wet flue gas desulfurization (FGD), is the most frequently used technology for post-combustion control of SO_2 emissions. It is commonly based on low-cost lime-limestone in the form of aqueous slurry. Lime is calcium oxide, CaO; Limestone is $CaCO_3$. The slurry brought into contact with the flue-gas absorbs the SO_2 in it. $CaSO_4$-$2H_2O$, Gypsum, is formed as a byproduct (1).

Gas flow per unit cross sectional area, which determines scrubber diameter, must be low enough to minimize entrainment. Mass transfer characteristics of the system determine absorber height. These vessels and the accompanying equipment used for slurry recycle, gypsum dewatering, and product conveyance tend to be quite large. Some variations of this technology produce high quality gypsum for sale. Less pure waste product may be sold for use in cement production. If neither of these options is practiced, the scrubber waste must be disposed of in a sludge pond or similar facility (2).

The wet scrubber has the advantage of high SO_2 removal efficiencies, good reliability, and low flue gas energy requirements (1).

What is being done:
San Juan Generating Station has initiated an Environmental Improvement program under its consent decree that includes enhanced SO_2 scrubbing. Projections show that optimization of SO_2 scrubbing will result in a reduction of SO_2 from the current emission rate of 16,569.5 tons/yr to an emissions rate of 8,900 tons/yr by the year 2010 (3, 4, 5). This would translate as an increase in SO_2 removal efficiency from 81% to 90% as required by the consent decree.

The Consent Decree that San Juan has entered into will require a minimum of 90% removal of SO2.

Four Corners Power Plant has also made significant improvements in SO_2 emissions control efficiency. APS, in partnership with the Navajo Nation, several environmental groups and federal agencies, conducted a test program to determine if the efficiency of the existing scrubbers at Four Corners Power Plant could be improved from the recent historical level of 72% SO_2 removal to 85%. The test program, which was completed in spring of 2005, was successful and the plant was able to achieve a plant-wide annual SO_2 removal of 88%. In fact, data indicates that a 92% removal, or 0.16 lbs/mmBtu SO2 limit was achieved. Some parties involved in the test program have agreed that a new rule should propose to require 88% removal efficiency for the Four Corners Power Plant (6). Parties are also interested, however, in a mass emissions limit as opposed to removal rate to protect against air quality degradation from higher sulfur coal.

The way "removal" is used here is based on including the amount of sulfur retained in the ash. For FCPP, this amounts to about 2% "bump-up" of the control efficiency. So, 88% removal is the equivalent of 86% control. By contrast, both the NM regulations and the SJGS consent decree require that the control efficiency across the scrubber be measured by CEMs before and after the scrubber.

72% SO_2 removal resulted in approximately 22,450 Tons/yr SO_2 emissions. The new emissions control removal efficiency of 88% translated to 12,500 Tons/yr SO2 emissions in 2005.

Further advances in SO_2 scrubber optimization should be explored and implemented as they become available. It may be possible to achieve over 90% SO_2 removal efficiencies with enhanced SO_2 scrubbing on existing power plants in the 4C area

During 2005, FCPP demonstrated that it can achieve better than 90% control of SO_2.

Benefits: SO_2 removal increase. Possible co-benefits are increased particulate removal, and also mercury removal.
Tradeoffs:
Burdens: Cost to existing power plants including: optimization controls or additional retrofit technologies.

II. Description of how to implement
A. Mandatory or voluntary
Voluntary emissions reductions that are above and beyond new standards

Differing Opinion: A FCPP FIP that reflects the capabilities of the control equipment and coal supply

B. Indicate the most appropriate agency(ies) to implement
New Mexico Air Quality Bureau
EPA Region 9 and Navajo Nation EPA

III. Feasibility of the option
A. Technical: technology is available and feasible.
B. Environmental: Optimized SO2 scrubbing could result in SO_2 control efficiency above 90%.
C. Economic: Improving existing emissions control process through optimization is often less expensive than retrofitting plant with entirely new emissions control equipment.

IV. Background data and assumptions used:
1. El-Wakil, M.M. Power Plant Technology; McGraw-Hill, New York: 2002.
2. Clean Coal Technology Topical Report #13, May 1999, DOE, "Technologies for the combined Control of Sulfur Dioxides and Nitrogen Oxides from Coal-fired Boilers"
3. Current estimated SO_2 emissions from Four Corners area power plants (4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV9)
4. San Juan Generating Station (SJGS) presentation for 4CAQTF, August 9, 2006, "SJGS Emissions Control Current and Future"
5. Clean Air Markets – Data and Maps – 2005 Unit Emissions Report – Emissions for San Juan Generating Station & Four Corners Steam Electric Station
6. Final rule for Four Corners Power Plant:
ENVIRONMENTAL PROTECTION AGENCY, 40 CFR Part 49, [EPA-R09-OAR-2006-0184; FRL-], Source-Specific Federal Implementation Plan for Four Corners Power Plant; Navajo Nation

V. Any uncertainty associated with the option
Medium – SO_2 scrubbing control efficiencies have increased recently. Optimization of SO_2 scrubbing systems have limitations.

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups None

EXISTING: ADVANCED NO_x CONTROL TECHNOLOGIES

Mitigation Option: Selective Catalytic Reduction (SCR) NO_x Control Retrofit

I. Description of the mitigation option,
To reduce NOx emissions from the existing power plants in the Four Corners area, a Selective Catalytic Reduction system could be retrofitted to San Juan Generating Station and Four Corners Power Plant.

Selective Catalytic Reduction, SCR, uses ammonia or urea along with catalysts in a post-combustion vessel to transform NO_x into nitrogen and water. It can achieve the 0.15-pound-per-million Btu standard (1).

Some eastern EGUs retrofitted with SCR have achieved 0.05 lb/mmBtu. Based on recent permit applications and boilers in the east that have retrofitted with SCR, this technology can typically achieve a 90 percent reduction in NO_x emissions.

Ammonia is used as the reducing agent. It is injected into the flue gas stream and then passes over a catalyst. The ammonia reacts with nitrogen oxides and oxygen to form nitrogen and water.

The main Selective Catalytic Reduction reaction is $4NH_3 + 4NO + O_2 \rightarrow 4\ N_2 + 6H_20$ (2)

Supplemental description of Selective Catalytic Reduction available from US EPA, AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01) (for Desert Rock Energy Facility)

This report further discusses technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst de-activation due to aging or poisoning, ammonia slip emissions, and design of the ammonia injection system (3).

And the SCR system
The SCR system is comprised of a number of subsystems. These include the SCR reactor and flues, ammonia injection system and ammonia storage and delivery system (3).

Based on heat input and emissions data from the Acid Rain Program:
Currently NO_x emissions from San Juan Generating Station are on the order of 0.42 lbs/mmBtu or 26,800 Tons/yr.
Currently NOx emissions from the Four Corners Power Plant are approximately 0.57 lbs/mmBtu or 40,700 Tons/yr (4). Note: FCPP is the largest NOx-emitting EGU is the US.

The proposed Desert Rock Energy facility is planning to build their facility with Selective Catalytic Reduction technology to control NO_x emissions. They expect 85-90% control of NOx. The permit allowed NOx emissions will be 0.060 lbs/mmBtu fuel input (2).

Retrofitting a Selective Catalytic Reduction to existing power plants would be much more difficult than installing equipment with the construction of the plant; however, it is an option to greatly reduce NOx emissions from existing sources. It may be able to reduce emissions from existing sources by as much as 50%.

Differing Opinion: Applying SCR to existing plants may be more difficult than new installation; it is not a given. SCR has been successfully applied in the East in response to the CAIR rule. Retrofits at eastern utilities subject to the NOx SIP Call and CAIR typically set a 90% reduction goal. The vintage EPA Cost Tool database assumes 70% control by SCR, and SCR has improved dramatically since then.

Benefits: It is an option to greatly reduce NOx emissions from existing sources. It may be able to reduce emissions from existing sources by as much as 50% - 90%+. SCR may have some co-benefit reductions of Mercury emissions.

Tradeoffs:
Ammonia that is not reacted will "slip" through into exhaust. Ammonium salts could also form thus increasing loading to the particulate collection stage as PM10 (and PM2.5) (2). This is less likely with lower sulfur coal.
SCR tends to increase the reaction of SO_2 to SO_3 and increases the formation of acid mists. This could require additional treatment of the flue gas. This is less likely with lower sulfur coal.

Any analysis should compare the cost of SCR to the costs of combustion controls.

Application of EPA's Cost Tool model for the Four Corners Power Plant, Units 4 & 5 predicts that NO_x could be reduced by 70 percent to the levels shown by application of combustion controls plus SCR at a cost of $409 - $464 per ton of NO_x removed. EPA states that the average cost of combustion controls on cell burners (presumptive BART) is $1021 per ton. The average cost of applying SCR to cyclone units, (which for those units is presumptive BART), is $900 per ton.

Burdens: Retrofit costs to existing power plants. Installation may be cost prohibitive for some existing plants because of the physical layout of the plant. Safety issue with handling of ammonia for use as reducing agent

II. Description of how to implement
A. Mandatory or voluntary
Retrofit program could be mandatory or voluntary
SCR application could be considered in the context of BART.

B. Indicate the most appropriate agency(ies) to implement
State Air Quality Bureaus, Federal EPA, Industry

III. Feasibility of the option
A. Technical – commercially available

B. Environmental – high reduction efficiencies demonstrated 85-90+%.
Sulfur content of the coal is an important factor in use of SCR. The low-sulfur coals burned in the 4 Corners area should be more compatible with SCR. SCR is being widely applied to a variety of bituminous and sub-bitumninous coals, especially in the East. Requiring catalyst replacement is an economic issue.

The SCR process is subject to catalyst deactivation over time (2).

C. Economic – Retrofit costs. Additional maintenance costs

*Cumulative Effects Work Group – How would 50%-90% emissions reductions from the two existing power plants affect visibility and ozone?
*Monitoring Work Group – Would it be possible to measure ammonia slip in the exhaust gases?

IV. Background data and assumptions used

1. US Department of Energy (DOE) Pollution Control Innovations Program
http://www.fossil.energy.gov/programs/powersystems/pollutioncontrols/index.html

2. Development of Nitric Oxide Catalysts for the Fast SCR Reaction, Matt Crocker, Center for Applied Energy Research, University of Kentucky (2005)

3. US EPA, AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01) (for Desert Rock Energy Facility)
*A good description of Selective Catalytic Reduction is available on pp.9-10 of the US EPA, Ambient Air Quality Impact Report, Best Available Control Technology discussion, for the Desert Rock Energy Facility.

4. Clean Air Markets – Data and Maps – 2005 Unit Emissions Report – Emissions for San Juan Generating Station & Four Corners Steam Electric Station
Heat input for all 4 units at San Juan Generation Station 127,629,979 mmBtu in 2005.
Heat input for all 5 units combined at 4Corners Power Plant 141,394,388 mmBtu in 2005.

5. San Juan Generating Station (SJGS) presentation for 4CAQTF, August 9, 2006, "SJGS Emissions Control Current and Future"

V. Any uncertainty associated with the option High.

Differing Opinion: The success of SCR in reducing NO_x emissions is a proven technology

VI. Level of agreement within the work group for this mitigation option To Be Determined.

VII. Cross-over issues to the other Task Force work groups

Oil & Gas industry may also look at SCR as a method to reduce natural gas compressor NO_x emissions

Mitigation Option: BOC LoTOx^{TM} System for the Control of NOx Emissions

I. Description of Mitigation Option

Belco BOC LoTox is an oxidation technology for flue gas NOx control. It was developed in recent years and has become commercially successful and economically viable as an alternative to ammonia and urea based technologies. Older commercial technologies such as Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR), which reduce NOx to nitrogen using ammonia or urea as an active chemical, are limited in their use for high particulate and sulfur containing NOx streams such as from coal-fired combustors, or are unable to achieve sufficient NOx removal to meet new NOx regulation levels. In contrast, oxidation technologies convert lower nitrogen oxides such as nitric oxide (NO) and nitrogen dioxide (NO2) to higher nitrogen oxides such as nitrogen sesquioxide (N2O3) and nitrogen pentoxide (N2O5). These higher nitrogen oxides are highly water soluble and are efficiently scrubbed out with water as nitric and nitrous acids or with caustic solution as nitrite or nitrate salts. NOx removal in excess of 90% has been achieved using oxidation technology on NOx sources with high sulfur content, acid gases, high particulates and processes with highly variable load conditions.

The BOC LoTOx^{TM} System is based on the patented Low Temperature Oxidation (LTO) Process for Removal of NOx Emissions, exclusively licensed to BOC Gases by Cannon Technology. This technology has met the stringent cost and performance guidelines established by the South Coast Air Quality Management District in Diamond Bar, CA and has set new lower limits for Best Available Control Technology (BACT) and Lowest Achievable Emissions Reduction (LAER). The LoTOx^{TM} System for NOx Control uses oxygen to produce ozone as the primary treatment chemical using an ozone generator. The oxidation of NOx using ozone is a naturally occurring process in the atmosphere. The absorption of higher nitrogen oxide by water to form nitric acid is also a naturally occurring process in the atmosphere, resulting in “acid rain”. The LoTOx^{TM} System reproduces these naturally occurring processes under controlled conditions within an enclosed system. This treatment method produces the treatment chemical, ozone, on demand from gaseous oxygen in the exact amount required for oxidation of the NOx.

A demonstration was conducted at Southern Research Institute’s (SRI) Combustion Research Facility, Birmingham, AL using a mobile demonstration trailer. The test was the first in a series of tests planned to demonstrate the effectiveness of ozone for oxidation and removal of NOx emissions from SRI’s coal-fired combustor. The results from the tests demonstrated that the LoTOx^{TM} System is highly effective for removal of NOx emissions from as high as 350 ppmv NOx to below 50 ppmv NOx levels without significant residual ozone in the exhaust stream. The LoTOx^{TM} System is very selective for NOx removal, oxidizing only the NOx and therefore efficiently using the treatment chemical, ozone, without causing any significant SOx oxidation and without affecting the performance of the downstream SOx scrubber. Furthermore the ozone/NOx ratios required to produce desired NOx oxidation are less than the predicted stoichiometric amounts. Various types of coals and fuel types will be used in the combustor. The information gathered will be used for the design of commercial LoTOx^{TM} Systems for effective and efficient NOx removal at utility power plants and other large-scale NOx sources. [1]

Chemistry

The LoTOx process is based on the excellent solubility of higher order nitrogen oxides. Typical combustion processes produce NOx streams that are approximately 95% NO and 5% NO2. Both NO and NO2 are relatively insoluble in aqueous streams, therefore, wet scrubbers will only remove a few percent of NOx from the flue gas stream. Species Solubility at 25°C and 1 atm

NO 0.063 g/l, NO2 1.260 g/l

The LoTOx process uses ozone to oxidize NO and NO2 to N2O5 ,which is highly soluble, and by wet scrubbing N2O5 is easily and quickly converted to HNO3, based on the following reactions:

NO + O3 -> NO2 + O2

2NO2 + O3 -> N2O5 + O2

$N_2O_5 + H_2O \rightarrow 2HNO_3$

Both N_2O_5 and HNO_3 are extremely soluble in water. N_2O_5 reacts instantaneously with water forming HNO_3. Since HNO_3 is so highly soluble (approaching infinity) it is difficult to measure, and therefore reliable solubility data is not available in published literature. However, HNO_3 mixes with water in all proportions and therefore the N_2O_5 to HNO_3 reaction is irreversible in the presence of water. [2]

Benefits: Low Temperature, No chemical slip
Tradeoffs:

Burdens:
Ozone unused in the treatment process produces no health hazards to plant workers nor to the environment. The ozone is injected into flue gas stream where it reacts with relatively insoluble NO and NO_2 to form N_2O_3 and N_2O_5, which are highly water soluble, and are easily and efficiently removed and neutralized in a wet scrubbing system. [1]

II. Description of how to implement

A. Mandatory or voluntary
LoTOx could be the answer to achieve required limits under regional haze rule. This control technology could be an option to meet mandatory emissions limits

B. Indicate the most appropriate agency(ies) to implement
4 Corners Power Plants would implement new technology as an integrated component of emissions control system

III. Feasibility of the option

A. Technical: Low temperature reaction is good. Ozone generation and other LoTOx system components are well understood technologies used in other applications.
B. Environmental: Pilot scale demonstrations showed 90% removal, very high reduction efficiencies
C. Economic: Retrofit technologies can be expensive on existing power plants.

This technology has only been tested on pilot plants and there are no full scale installations. The technology should therefore, at this point, be considered not technically feasible.

IV. Background data and assumptions used

1. DEMONSTRATION AND FEASIBILITY OF BOC LoTOx™ SYSTEM FOR NOx CONTROL ON FLUE GAS FROM COAL-FIRED COMBUSTOR abstract, presented at 2000 Conference on SCR & SNCR for NOx Control/BOC, http://www.netl.doe.gov/publications/proceedings/00/scr00/ANDERSON.PDF
2. CARB Innovative Clean Air Technology, "Low Temperature Oxidation System Demonstration," BOC paper 1999, http://arbis.arb.ca.gov/research/apr/past/icat99-2.pdf
3. DuPont BELCO LoTOx Technology homepage http://www.belcotech.com/products/nox.html

V. Any uncertainty associated with the option

Medium, any retrofit technology has a degree of uncertainty. It can be difficult and expensive to retrofit emissions control technology that the plant was not originally designed for.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

EXISTING: OTHER RETROFIT TECHNOLOGIES

Mitigation Option: Baghouse Particulate Control Retrofit

I. Description of the mitigation option

Installation of baghouses at existing power plants in the Four Corners area could reduce particulate emissions by approximately 25% or more. Baghouses, or fabric filters, as they are often called, collect fly ash and other particulate matter from the coal combustion process like large vacuum cleaners. Typically a baghouse removes more than 99.8 % of the fly ash.

The original design for the two major power plants in the 4 Corners area was for electrostatic precipitators (ESPs). The ESPs on San Juan Generating Station remove approximately 99.7 % of the particulate matter from the exhaust stream. This exceeds current state and federal emissions requirements (0.1 lbs/mmBtu and 0.05 lbs/mmBtu).

The San Juan generating station is currently undergoing a series of environmental improvements between 2007 and 2009 including designing for a 0.015 lbs/mmBtu particulate limit. PNM will install fabric filters (baghouses) for all four SJGS units collect particulate emissions. The ESPs at San Juan will remain in place but will be de-energized. It is believed that a portion of the ash will continue to be removed in the ESPs (because of gravity separation) but they will not be considered a control device. One of the reasons to install the baghouses was because of PNM's commitment for Activated Carbon Injection for the removal of mercury. An ESP would not have been efficient in the collection of the activated carbon. An additional benefit of the baghouse is the reduction of opacity spikes that are caused by an increase in unburned carbon in the flyash. This unburned carbon is caused by combustion problems associated with the operation of the low-NOx burners and is not efficiently collected by an ESP. Also, we will not know until the Baghouses are installed and operational, but we do not anticipate that the actual particulate emissions will be significantly less than the current emissions. However, the permit requirement will be reduced from 0.05 lbs/mmBtu to 0.015 lbs/mmBtu.

Since all units at San Juan and Units 4 & 5 at Four Corners currently have or will have baghouses in the near future, this option will only apply to Units 1,2 & 3 at Four Corners.

Benefits: Current reported levels of particulate emissions at major power plants in the 4Corners area include: San Juan Generating Station emits approximately 673 Tons/yr, approximately .011 lbs/mmBtu; 4 Corners Power Plant emits approximately 1,187 Tons/yr, approximately .017 lbs/mmBtu (see 4CAQTF_PowerPlant_WorkGroup_ FacilityDataTableV10). Baghouse installation may result in improved particulate removal efficiencies. If baghouses could reduce emissions to .010 lbs/mmBtu, this option could lead to over 500 tons per year reduction of particulates collectively from the two largest coal fired power plants in the region.

Differing Opinion: The benefits (500 ton reduction of particulates) may be over estimated because San Juan and Four Corners Unit 4 & 5 will have baghouses and will perform at or close to the 0.01 lbs/mmBtu. The only units that would see a reduction would be Four Corners Units 1,2 & 3.

Burdens: Cost of baghouse installation on power plants

II. Description of how to implement

A. Mandatory or voluntary
Voluntary or consent decree

B. Indicate the most appropriate agency(ies) to implement
Power Plants would install

III. Feasibility of the option
A. Technical: Technology is available commercially

B. Environmental: Feasible

C. Economic: Expensive to install new technology

IV. Background data and assumptions used
1. San Juan Generating Station (SJGS) Emissions Control Current and Future, presentation for 4CAQTF, May 2006 ,http://www.nmenv.state.nm.us/aqb/4C/Docs/SanJuanGeneratingStation.pdf

2. 4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10

3. Clean Air Markets – Data and Maps – 2005 Unit Emissions Report – Emissions for San Juan Generating Station & Four Corners Steam Electric Station
Heat input for all 4 units at San Juan Generation Station 127,629,979 mmBtu in 2005.
Heat input for all 5 units combined at 4Corners Power Plant 141,394,388 mmBtu in 2005.

4. San Juan Environmental Improvement Upgrades Fact Sheet,
http://www.pnm.com/news/docs/2005/0310_sj_facts.htm

V. Any uncertainty associated with the option
Medium.

VI. Level of agreement within the work group for this mitigation option
TBD.

VII. Cross-over issues to the other Task Force work groups
None.

Mitigation Option: Mercury Control Retrofit

I. Description of the mitigation option
Existing power plants in the Four Corners area should evaluate the installation of mercury removal technology to reduce mercury emissions. According to EPA's 2005 Toxic Release Inventory report the San Juan Generating Station released 770 lbs and Four corners Power Plant released 625 lbs of mercury into the air. Activated carbon injection technology is the most likely control technology at this time. This technology has been demonstrated in several pilot studies.

The Clean Air Mercury Rule (CAMR) will require the reduction of mercury emissions from power plant beginning in 2010 with further reductions in 2018. This rule will also require the installation of mercury Continuous Emissions Monitoring systems by January 1, 2009.

San Juan Generating Station will have mercury control (activated carbon injection) on all four units by 2010 and Mercury CEMs on 2 units by 2008 and all 4 units by 2009.

II. Description of how to implement
A. Mandatory or voluntary: Mandatory and/or Voluntary

B. Indicate the most appropriate agency(ies) to implement
Regulating agencies:
EPA Region 9 Air Programs, Navajo Nation EPA, New Mexico Environment Department

III. Feasibility of the option
A. Technical: The injection of activated carbon into the flue gas stream has been demonstrated in pilot studies to remove mercury. However, there have not been any long-term applications of this technology. Also the effectiveness of this technology has not been demonstrated on the type of coal in the San Juan Basin so the actual removal efficiency of the technology is unknown. Nevertheless, many new coal-fired power plant projects are proposing installation of activated carbon injection.

B. Environmental: Mercury emissions will be reduced, however, the addition of activated carbon to the fly ash will make the ash unsuitable for sale to the cement/concrete industry and will increase the amount of fly ash that will have to be disposed.

C. Economic: The cost of additional equipment for ACI injection is relatively small, however, the annual operating and maintenance cost can be significant because of the cost of the activated carbon. Also there currently is a limited supply of activated carbon. The increase cost for ash disposal could be significant. Also, ACI injection requires a bag house or fabric filter for particulate control. This cost would be significant if this technology would have to be retrofitted to existing units.

IV. Background data and assumptions used N/A.

V. Any uncertainty associated with the option Medium.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

EXISTING: STANDARDS

Mitigation Option: Harmonization of Standards

I. Description of the mitigation option,
This option would require existing power plants to meet the most stringent standard of any governmental agency in the region, i.e., the strictest state, federal, or tribal standard. At present facilities are subject to varying standards depending on where they are located, even though emissions affect the entire area and beyond.

This option is limited to existing power plants on the basis that new power plants are held to Best Available Current Technology (BACT) limitations on controlled emissions, which are usually much lower than current state or federal air standards.

One of problems in the Four Corners area is the aging fleet of large power plants. These older power plants have significantly higher emissions than potential new sources. The two largest generating stations in the Four Corners Region, Four Corners Power Plant (FCPP) and the San Juan Generating Station (SJGS), are regulated by different agencies even though they are within 30 miles of each other. San Juan Generating Station is being held to more stringent regulations by the New Mexico Air Quality Bureau regulations.

The burden of this requirement to adopt more stringent regulations would fall on the owners of the facilities and might also lead to the eventual retirement of some older Four Corner area power plants. However, the long-term effect of this rule, especially if applied to other multi-state regions over time, might lead to standardized regulations, also a benefit, if the new standards converged on the most stringent requirement.

II. Description of how to implement
This rule should be mandatory and phased in over a designated period of time.

A valuable lesson is to be learned from the Four Corners Power Plant jurisdiction quandary. The Navajo Tribe ruled that the State of NM cannot regulate and enforce FCPP emissions. Very recently, a lawsuit was filed against the Federal EPA regarding FCPP emissions. This lawsuit may have expedited the current series of action by the Federal EPA such as public sessions, the FIP, etc. The FCPP is on tribal land, but the air emissions affect the entire Four Corners area. Somehow, a regulatory agency responsible for governing and enforcing emissions of present and future power plants and oil and gas facilities should be agreed upon by all entities.

The area’s ozone problem is an example of why it is important to have one regulatory agency. The Four Corners area has unusually high volumes of ground level ozone. The Four Corners Ozone Task Force (FCOTF) has been working for the past several years on ozone mitigation options. The FCOTF is working closely with EPA Region 6. Recently EPA Region 9 officials came to the area to talk about the proposed Desert Rock coal fired power plant. This area’s ozone problems were not addressed by EPA Region 9 in the Desert Rock Proposed PSD Permit. In order to avoid costly environmental oversights and/or confusion, only one EPA Region should be designated as the Federal Agency to regulate and enforce in an area such as the Four Corners.

Differing Opinion: Implementing this option could initially be voluntary, as it would ultimately require changes to the Clean Air Act and/or Code of Federal Regulations to address tribal authority over air programs, and the role of the Federal Implementation Plan.

III. Feasibility of the Option
Technical issues: none, technology currently exists to meet the most stringent existing requirement

Environmental issues: Benefits of stricter standards are intuitive. The following are examples of significant disparities in state and federal limits:

For example, the current State permit limit for NOx emissions from San Juan Generating Station is 0.46 lbs/mmBtu. The federal limits for NOx at Four Corners Power Plant are 0.65 – 0.85 lbs/mmBtu. San Juan Generating Station NOx emissions rate is approx. 0.4 lbs/mmBtu or 26,800 Tons/yr. Four Corners Power Plant, under the federal regulation, emits approx 0.6 lbs/mmBtu or approx 41,700 tons/yr

The state limit for SO_2 emissions from San Juan Generating Station is 0.65 lbs/mmBtu. The federal limit applied to Four Corners Power Plant is 1.2 lbs/mmBtu. The state permit limit for PM emissions from San Juan Generating Station is 0.05 lbs/mmBtu. The Federal PM standard is 0.1 lbs/mmBtu.

Economic: Implementation of resulting standards could be expensive. Experience of the political unit currently having the strictest standard could provide some data on the cost. In any case, the standard, even though not industry-wide, would be applicable area-wide and therefore more fair to competing power generators

Political issues: resistance would be great, just as it is now to tightening of standards. Effective implementation of this idea might require creation of a Four Corners regional authority or special district, which might require enabling legislation: the difficulty of accomplishing this is unknown.

IV. Background data and assumptions
The Federal/State PSD rules are applied industry wide for new power plants and existing power plants with major modifications in NAAQS attainment areas. Existing power plants in different jurisdictions continue to be regulated by different standards even though they are in the same air basin. This option would be a step in harmonizing standards. It is clear that the two plants we have heard from could meet tighter standards, especially when applied industry-wide; but since they are not required to do so, they cannot get their owners to support meeting them. It is intuitive that if any installation in the Four Corners region using San Juan Basin coal can meet the tightest standard, they all can over a reasonable period of time.

Green House Gases Such as Carbon Dioxide –
It is becoming more and more apparent that Global Warming or Climate Changes is a world wide problem. Reductions in carbon dioxide emissions, one of the green house gases, should be addressed in the Mitigation Options for all existing and future coal fired power plants in the San Juan Basin. The carbon dioxide issue will have to be dealt with sooner or later and the sooner, the better.

New Mexico Environmental Regulations for Air Quality may be found at:
http://www.nmenv.state.nm.us/aqb/regs/index.html

V. Any uncertainty associated with the option
There is a high level of uncertainty in getting something like this passed politically and how long it would take is an unknown.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues Oil and Gas Work Group, Other Sources Work Group.

EXISTING: MISCELLANEOUS

Mitigation Option: Emission Fund

I. Description of the mitigation option

This option would establish an emissions fund for emitters of one or more air pollutants of concern, such as nitrogen oxides. Sources emitting more than a specified amount annually would pay by the ton emitted into a fund that would then be used for environmental improvement projects. There should be no maximum number of tons over which fees wouldn't be paid.

The fund should be used for environmentally beneficial projects, to be decided by the administering body (see below). One option is to have a grant system whereby applications are made to the fund by anyone—regulated community, environmental community, public, academia, etc—and the administering body would have set criteria against which they evaluated each request. Another option is to specify the allowable uses of the fund, such as for the development or investment in innovative technologies.

Benefits: Ideally, emitters required to pay per ton emitted would have an incentive to emit less. To make this incentive effective, the fee per ton would need to be relatively high. A thorough search of similar programs and any evaluations of those programs should be done to determine what fee level would provide an effective incentive. Monetary incentives could result in emission reductions at significantly lower costs than "command and control" regulation. Emission fees also work to "internalize the externalities" involved in air emissions and environmental degradation by recognizing and attempting to account for the social costs of the operations of the emitters.

Burdens: the primary burden would be on the emitter, to pay into the fund based on annual emissions. There would be some administrative burden, lessened by using existing reporting and oversight frameworks to implement the program.

II. Description of how to implement

A. Mandatory of voluntary: Payment into an emission fund would be mandatory for a defined size or class of sources

B. Most appropriate agency to implement: These programs have generally been administered by state agencies. Tribal air quality agencies could also develop and implement an emissions fund. An oversight committee or the air quality entity with regulatory authority would have authority to administer the fund. The committee or board should have members representing the regulated community, environmental community and general public.

The program could be phased in: fees per ton of emissions of specified pollutant(s) could gradually be increased over 5-10 years. The program could be based on existing permitting systems: fees would be based on the number of tons reported emitted, via existing reporting requirements within permits or any other existing framework for reporting.

III. Feasibility of the option

Emissions funds for air pollution are used in France, Japan and many states as well. There are no technical feasibility issues associated with this option.

IV. Background data and assumptions used

Stavins, R. (Ed.) (2000). *Economics of the Environment (4th Ed.)*. WW Norton: New York, New York.
New Hampshire Code of Administrative Rules, Chapter Env-A 3700: *NOx Emissions Reduction Fund for NOx-Emitting Generation Sources*.

Ohio EPA *Synthetic Minor Title V Facility Emission Fee Program*. http://www.epa.state.oh.us/dapc/synmin.html. (via statute--need cite).

Texas Administrative Code, Title 30, Part 1, Chapter 101, Subchapter A, Rule sec. 101.27: *Emissions Fees*

V. Uncertainty

VI. Level of agreement within workgroup

VII. Cross-over issues to other workgroups

The oil and gas industry could be subject to the emissions fund.

PROPOSED POWER PLANTS: DESERT ROCK ENERGY FACILITY

Mitigation Option: Desert Rock Energy Facility Stakeholder Funding to and Participation in Regional Air Quality Improvement Initiatives such as Four Corners Air Quality Task Force

I. Description of the mitigation option

Sithe Global and other stakeholders in Desert Rock Energy Facility will provide time and resource commitments to participate in inter-agency environmental initiatives to improve air quality in the Four Corners area.

Background:
Sithe Global Power, LLC proposes to construct a 1,500 Megawatt hybrid dry cooled coal-fired electric power-generating plant south of Farmington in northwestern New Mexico, per the project development agreement entered into with Diné Power Authority (1).

The proposed Desert Rock Energy Facility is located within the New Mexico portion of the Four Corners Interstate Air Quality Control Region. The area is currently designated as attainment for all regulated pollutants: nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter less than 10 microns in aerodynamic diameter (PM10), lead, and ozone (regulated as volatile organic compounds (VOC) and oxides of nitrogen (NOx)). There are concerns, however, with air pollution in the area and the effects on human health, visibility, and other air quality related values. The Facility's surrounding area is classified as Class II. The nearest Class I area is the Mesa Verde National Park, which is located approximately 75 kilometers (km) north of the site. The Grand Canyon National Park is located approximately 290 km west of the site (3). There are nine National Park Service Class I areas and six Forest Service Class I areas within 300 km of this proposed facility.

While the Desert Rock Energy Facility is using newer environmental emission control technology that on average have higher reduction efficiencies than existing facilities, the proposed power plant will still be adding substantial NO2, SO2, particulate, and other emissions to the Four Corners Area. See appendix 1.

Industry support would help to provide the resources necessary to ensure the air quality in the Four Corners, including our National Ambient Air Quality Standards (NAAQS) attainment, is maintained. There are substantial stakeholder interests in having air quality cleaner than simply meeting the NAAQS, for example, to improve visibility.

Desert Rock Energy LLC submitted a set of comments on the Four Corners Air Quality Task Force report during the public comment period. Desert Rock's comments included a discussion of a Voluntary Regional Air Quality Improvement Plan, CO2 emissions, and IGCC in relation to the proposed facility. The comments are located in an appendix at the end of the Power Plants section.

Benefits: Environmental initiatives will be supported by industries that contribute to the air quality issues. Much needed financial support will be provided to regional environmental initiatives. Information resources will be provided to help in the environmental regulation planning process.

Tradeoffs: None

Burdens: Sithe Global and other stakeholders will provide time and resource commitment to participate in inter-agency environmental initiatives in the Four Corners area.

II. Description of how to implement
A. Mandatory or voluntary
Voluntary or mandatory

Differing Opinion: Mandatory: because of the fact that the Four Corners Area is already heavily polluted by several industrial sources such as the Four Corners Power Plant and the San Juan Generating Facility, over 19,000 oil and gas wells (over 12,500 new wells are planned in the next two decades), a fast growing population, more motor vehicles, etc.

B. Indicate the most appropriate agency(ies) to implement
Environmental Protection Agency (EPA) Air Programs
Desert Rock Energy Project voluntary participation

Differing Opinion: According to an article in the December 11, 2006 "Farmington Daily Times" titled "Navajo Nation to Partially Own Desert Rock", "Representatives from the Dine Power Authority (DPA) say they will operate the proposed Desert Rock Power Plant with at least one degree of separation from the Navajo Nation Environmental Protection Agency (NNEPA) which will have oversight of the project." This should be a major concern. The Desert Rock Power Plant if built, must be closely monitored and enforcement must be very strict. There are concerns that a conflict of interest may exist. The Federal EPA should be the governing agency.

III. Feasibility of the option
Feasible.

IV. Background data and assumptions used
Literature cited
(1) Desert Rock Energy Project FACT SHEET #1, DEC 2004 (http://www.desertrockenergy.com/)
(2) 4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10
(3) AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)

V. Any uncertainty associated with the option
Low.

VI. Level of agreement within the work group for this mitigation option.
To Be Determined.

VII. Cross-over issues to the other Task Force work groups
None.

Table 1. Estimated Maximum Annual Potential Emissions from Desert Rock Energy Facility [Source: AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)]

Pollutant	PC Boilers (tpy)	Auxiliary Boilers (tpy)	Emergency Generators (tpy)	Fire Water Pumps (tpy)	Material Handling (tpy)	Project Estimated Emissions
NOx	3,315	7.13	2.26	0.41	n/a	3,325
CO	5,526	2.55	0.17	0.031	n/a	5,529
VOC	166	0.17	0.11	0.019	n/a	166

SO2	3,315	3.61	0.068	0.012	n/a	3,319
PM[2]	553	1.02	0.083	0.015	16.1	570
PM10[3]	1,105	1.68	0.077	0.014	12.9	1,120
Lead	11.1	0.00064	0.00012	0.0000022	n/a	11.1
Fluorides	13.3	neg	neg	neg	neg	13.3
H2SO4	221	0.062	0.002	0.0004	n/a	221
Mercury	0.057	0.000071	neg	neg	n/a	0.057

[1]tpy -tons per year
[2]PM is defined as filterable particulate matter as measured by EPA Method 5.
[3]PM_{10} is defined as solid particulate matter smaller than 10 micrometers diameter as measured by EPA Method 201 or 201A plus condensable particulate matter as measured by EPA Method 202. EPA is treating PM_{10} as a surrogate for $PM_{2.5}$.

Mitigation Option: Emissions Monitoring for Proposed Desert Rock Energy Facility to be used over Time to Assess and Mitigate Deterioration to Air Quality in Four Corners Area

I. Description of the mitigation option

The present proposed monitoring permit requirements for Desert Rock Energy Facility address only measurement of permit standards while there is another category of monitoring which could and should be done. This category would be data needed or useful for the evaluation of mitigation options in the present or the future.

PROPOSED ADDITIONAL MONITORING

a. PM2.5 continuous monitoring requirement.

The Four Corners region has several class 1 areas and a long term requirement by the EPA for improving visibility. PM2.5 is a critical element in this problem and future mitigation of it will require precise knowledge of the relative contributions from multiple and varied sources. This could come about by inclusion in the EPA permit conditions or by the company adding it to what they are doing to protect themselves from future finger pointing. Either way the data needs to be publicly available so those evaluating mitigation options have the use of it.

Total filterable PM CEMs have been certified by EPA. EPA contends that there is no currently certified method to continuously monitor PM_{10} or $PM_{2.5}$. However, there are some PM CEMs vendors that suggest CEMS can be modified to monitor a certain particulate size fraction.

b. Speciated Mercury (Hg) stack emission plus a plume contact measurement.

This region now has several lakes where restrictions of fishing exist because of Hg levels in the fish. The sources of Hg are multiple (geology, mining, oil & gas, agriculture, and power plants) to devise a proper mitigation plan the Hg species will need to be known so that sources can be identified and contribution determined. Models which predict Hg species in the environment from those found in the stack have shown problems. (Hg Speciation in Coal-fired Power Plant Plumes Observed at Three Surface Sites in the SE U.S.,Environ. Sci. Technol.2006, 40, 4563-4570:Modeling Hg in Power Plant Plumes, Environ. Sci. Technol,2006, 40,3848-3854) For this reason sampling at plume ground contact needs to be done to determine species for our environment and plant and coal types as the Hg enters the environment since we can not count on modeling to give correct Hg speciation. The stack sampling should be required under the permit plume surface contact samples however might be a cooperative venture between state or tribal personnel and the company. (State or Tribal personnel taking the sample and this sample then run by the company with the stack sample.)

c. VOC sampling in addition to that presently specified in the permit.

While the VOC's are nowhere near levels that would cause general health problems they are critical to the processes involved in the visibility problem which needs addressing. VOC's react in the plume after emission and change. A measurement of the VOC's after the initial reaction in the plume would be advantageous since it would give what is present to react to give the visibility problems. The VOC's present after this initial reaction is usually predicted by modeling however the literature indicates there are some problems with this approach measurements made at the plume ground contact could be a joint operation. State or Tribal personnel might collect a sample with the company running the sample with their stack sample.

II. Description of how to implement

A. Mandatory or voluntary

Desert Rock Energy Facility would be responsible for facility monitors

There are concerns that there are not enough monitors in place in the Four Corners Area and that the existing monitors are not placed in optimum locations. Several more monitors in logical locations must be installed in order to accurately measure emissions. The Federal, State, and Tribal EPA agencies should be responsible for collection and analyzing samples. The Four Corners Power Plant and the San Juan Generating Station are among the dirtiest coal fired power plants in the Nation. Desert Rock must be placed under strict scrutiny. The Four Corners Area is already close to ground level ozone levels of non-attainment. The area cannot afford further degradation of the air quality.

B. Indicate the most appropriate agency(ies) to implement
State or Tribal personnel might collect and analyze some samples

III. Feasibility of the option
A. Technical
B. Environmental
C. Economic

*Monitoring Work Group – assess the feasibility (technical, environmental, and economic) of conducting the proposed monitoring.
*Cumulative Effects Work Group – Will the proposed additional monitoring in this mitigation option be useful in assessing the Desert Rock Energy Facility point source contributions to the cumulative Four Corners area air quality?

IV. Background data and assumptions:

V. Any uncertainty associated with the option (Low, Medium, High)
Low

VI. Level of agreement within the work group for this mitigation option
TBD

VII. Cross-over issues to the other source groups
None

Mitigation Option: Coal Based Integrated Gasification Combined Cycle (IGCC)

I. Description of the mitigation option
Consideration of IGCC technology, as an alternative to a pulverized coal fired boiler, should be considered in the BACT analysis.

Sithe Global Power, LLC proposes to construct a 1,500 Megawatt hybrid dry cooled coal-fired electric power-generating plant south of Farmington in northwestern New Mexico, per the project development agreement entered into with Diné Power Authority (1).

The proposed Desert Rock Energy Facility is located within the New Mexico portion of the Four Corners Interstate Air Quality Control Region. The area is currently designated as attainment for all regulated pollutants: nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter less than 10 microns in aerodynamic diameter (PM10), lead, and ozone (regulated as volatile organic compounds (VOC) and oxides of nitrogen (NOx)). There are concerns, however, with air pollution in the area and the effects on human health, visibility, and other air quality related values. The Facility's surrounding area is classified as Class II. The nearest Class I area is the Mesa Verde National Park, which is located approximately 75 kilometers (km) north of the site. The Grand Canyon National Park is located approximately 290 km west of the site (2). There are nine National Park Service Class I areas and six Forest Service Class I areas within 300 km of this proposed facility.

On July 7, 2006, the Environmental Protection Agency (EPA) released a technical report titled "The Environmental Footprints and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies." The Report provides information on the environmental impacts and costs of the coal-based integrated gasification combined cycle (IGCC) technology relative to conventional pulverized coal (PC) technologies.

"IGCC is a power generation process that uses a gasifier to transform coal (and other fuels) to a synthetic gas (syngas), consisting mainly of carbon monoxide and hydrogen. The high temperature and pressure process within an IGCC creates a controlled chemical reaction to produce the syngas, which is used to fuel a combined cycle power block to generate electricity. Combined-cycle power applications are one of the most efficient means of generating electricity because the exhaust gases from the syngas-fired turbine are used to create steam, using a heat recovery steam generator (HRSG), which is then used by a steam turbine to produce additional electricity (3)."

Consideration of IGCC technology, as an alternative to a pulverized coal fired boiler, was not included in the BACT analysis for the Desert Rock Energy Facility (2).

Desert Rock Energy LLC submitted a set of comments on the Four Corners Air Quality Task Force report during the public comment period. Desert Rock's comments included a discussion of IGCC. Please see the comment in its entirety in the appendix to the Power Plants section.

Benefits: For traditional pollutants such as nitrogen oxides (NOx), sulfur dioxide (SO2), particulate matter (PM) and mercury (Hg), IGCC is inherently lower polluting than the current generation of traditional coal-fired power plants. IGCC also has multi-media benefits, as it uses less water than Pulverized Coal facilities. IGCC also produces a solid waste stream that can be a useful byproduct for producing roofing tiles and as filler for new roadbed construction. IGCC also has the potential to reduce solid waste by using as fuel a combination of coal and renewable biomass products (3).

IGCC is considered one of the most promising technologies to reduce the environmental impacts of generating electricity from coal. EPA has undertaken several initiatives to facilitate the development and deployment of this technology

IGCC thermal performance (efficiency and heat rate) is significantly better than current generation pulverized coal technologies in the US;

The Capture of CO2 emissions from IGCC plants would be cheaper and less energy intensive than in conventional coal plants (3, 6)

<u>Tradeoffs:</u>
<u>Burdens:</u> IGCC has 10 – 20 % higher capital costs than conventional PC plants [3]
When carbon capture becomes mandatory, that cost disadvantage will likely disappear.

<u>II. Description of how to implement</u>
<u>A. Mandatory or voluntary</u>
Mandatory to look at IGCC as a Best Available Control Technology option for future power plants in the Four Corners area

Permit levels could be set based upon IGCC performance. It would be up to the source how to meet those limits with whatever technology it chooses.

This could be a new legislative requirement at the State or Tribal level

<u>B. Indicate the most appropriate agency(ies) to implement</u>
Policy options for use of Integrated Gasification Combined Technology could be developed by Environmental Protection Agency (EPA), Department on Energy (DOE), New Mexico Energy, Minerals, and Natural Resources Department (NMEMNRD).

*EPA could designate IGCC as a Best Available Control Technology.

Differing Opinion:
Assuming that coal gasification is an innovative fuel combustion technique for producing electricity from coal, EPA does not believe Congress intended for an "innovative fuel combustion technique" to be considered in the BACT review when application of such a technique would redesign a proposed source to the point that it becomes an alternative type of facility. In prior EPA decisions and guidance, EPA does not consider the BACT requirement as a means to redefine the basic design of the source or change the fundamental scope of the project when considering available control alternatives. Therefore, the question is whether IGCC results in a redefinition of the basic design of the source if the permittee is proposing to build a supercritical pulverized coal (SCPC) unit. EPA's view is that applying the IGCC technology would fundamentally change the scope of the project and redefine the basic design of the proposed source if a supercritical pulverized coal unit was the proposed design. Accordingly, consistent with our established BACT policy, we would not require an applicant to consider IGCC in a BACT analysis for a SCPC unit. Thus, for such a facility, we would not include IGCC in the list of potentially applicable control options that is compiled in the first step of a top-down BACT analysis. Instead, we believe that an IGCC facility is an alternative to an SCPC facility and therefore it is most appropriately considered under Section 165(a)(2) of the CAA rather than section 165(a)(4).

Four Corners state legislatures and/or Tribal Nations could legislate that IGCC be considered?

<u>III. Feasibility of the option</u>

A. Technical:
Development and implementation of IGCC technology is relatively new compared with the PC technology that has hundreds or thousands of units in operation globally. Currently in the US there are two gasification unit installations using coal to make electric power as the primary product. The two IGCC plants in commercial operation include the Tampa Electric Polk Power Station in Florida and the Wabash River Coal Gasification Repowering Plant in Indiana. Each has been in operation since the mid-1990s. Recently, however, a number of companies have announced plans to build and operate additional IGCC facilities in the US (3).

These plants have yet to maintain better than 80% availability after more than 10 years of operation. Improved process control strategies are needed to ensure optimum operation over the full range of operating conditions. Real time coal quality analysis is needed to stabilize the coal gasifier process. Several areas of instrumentation development are warranted by the challenging physical conditions of the high temperature, abrasive, slagging gasifier environment. Other areas of the IGCC process face unique challenges that require development efforts to achieve the high availability rate needed for economic viability.

IGCC plants have not been demonstrated larger than 300 MW. For Desert Rock, more/larger gasifiers and several combustion turbines would be needed to attain 1500 MW. This technology is promising, but needs much development funding before the investment community would take on the risk of building such a large IGCC facility.

B. Environmental: This is a process control option

C. Economic: IGCC has higher capital costs than conventional PC plants (3).

IGCC has not demonstrated the typical 85-95% PC plant availability factors necessary for viable on-going profitable operation.

Historically, concerns about operational reliability and costs presented issues of uncertainty for IGCC technology and impeded its deployment. Such conditions are changing toward the more rapid advancement of the IGCC option. IGCC is a versatile technology and is capable of using a variety of feed stocks. In addition to various coal types, feed stocks can include petroleum coke, biomass and solid waste. Along with electricity production, IGCC facilities are able to co-produce other commercially desirable products that result from the process. Some of these products include steam, oxygen, hydrogen, fertilizer feed stocks and Fischer-Troph fuels (3).

The operational versatility noted above for IGCC technology may mitigate the risk of higher costs. In addition, under the Energy Policy Act of 2005, there are provisions for tax credits and a DOE Loan Guarantee Program to provide incentives to facilitate the deployment of IGCC technology.
In 1994 EPA established the Environmental Technology Council (ETC) to coordinate and focus the Agency's technology programs. The ETC strives to facilitate innovative technology solutions to environmental challenges, particularly those with multi-media implications. The Council has membership from all EPA technology programs, offices, and regions and meets on a regular basis to discuss technology solutions, technology needs and program synergies. One of the technologies identified as a promising option to address the production of energy from coal in an environmentally sustainable way is IGCC. This technical report is part of the ETC initiative and supports the combined efforts of EPA and the Department of Energy to advance the use of IGCC technology (3).

IV. Background data and assumptions used:

(1) Desert Rock Energy Project FACT SHEET #1, DEC 2004 (http://www.desertrockenergy.com/)

(2) AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)
(3) Technical Report on the Environmental Footprint and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, Fact Sheet: http://www.epa.gov/airmarkets/articles/IGCCfactsheet.html
(4) Wabash River IGCC Topical Report 2000 – www.fossil.energy.gov/programs/powersystems/publications/Clean_Coal_Topical_Reports/topical20.pdf
(5) Pioneering Gasification Plants (DOE) – http://www.fe.doe.gov/programs/powersystems/gasification/gasificationpioneer.html
(6) Scientific American, September 2006 article, "What to do about Coal," pp. 68-75
(7) ISA-2005 "I & C Needs of Integrated Gasification Combines Cycles" Jeffrey N. Phillips, Project Manager, Future Coal Generation Options, Electric Power Research Institute – presented at the 15th Annual Joint ISA POWID/EPRI Controls and Instrumentation Conference, 5-10 June 2005, Nashville, TN

V. Any uncertainty associated with the option

Medium. Integrated Gasification Combined Cycle (IGCC) is still a relatively new technology. There are coal gasification electric power plants in the US and other nations.

VI. Level of agreement within the work group for this mitigation option

To Be Determined

VII. Cross-over issues to the other Task Force work groups:

None

Mitigation Option: Desert Rock Energy Facility Invest in Carbon Dioxide Control Technology

I. Description of the mitigation option

Sithe Global Power, LLC proposes to construct a 1,500 Megawatt hybrid dry cooled coal-fired electric power-generating plant south of Farmington in northwestern New Mexico, per the project development agreement entered into with Diné Power Authority (1).

The proposed Desert Rock Energy Facility is located within the New Mexico portion of the Four Corners Interstate Air Quality Control Region. The area is currently designated as attainment for all regulated pollutants: nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter less than 10 microns in aerodynamic diameter (PM10), lead, and ozone (regulated as volatile organic compounds (VOC) and oxides of nitrogen (NOx)). The Facility's surrounding area is classified as Class II. The nearest Class I area is the Mesa Verde National Park, which is located approximately 75 kilometers (km) north of the site. The Grand Canyon National Park is located approximately 290 km west of the site (2). There are nine National Park Service Class I areas and six Forest Service Class I areas within 300 km of this proposed facility.

CO_2 emissions are not regulated; however, they are the primary Greenhouse gas that causes global warming.

In June 2005, the Climate Change Advisory Group was created in New Mexico as the result of an executive order from the Governor. The Climate Change Advisory Group (CCAG) is tasked with preparing an inventory of current state (New Mexico) Greenhouse gas emissions, as well as a forecast of future emissions. An action plan with recommendations to reduce Greenhouse gas emissions in New Mexico is also being prepared (3).

The process of generating electricity is the single largest source of greenhouse gas emissions in the United States (34 percent) [4]. CO_2 emissions. The Desert Rock Energy Facility will contribute approximately 11,000,000 Tons/yr CO_2 emissions (5, 6).

Desert Rock is a new proposed power plant in the Four Corners area. Technology is now available to capture and store CO_2 emissions. Many of these technologies are easier and less expensive if integrated into the design and construction of the power plant, rather than added later as retrofits. Retrofitting generating facilities for Carbon Capture and Storage (CCS) is inherently more expensive than deploying CCS in new plants (7).

CO2 capture and storage involves capturing the CO2 arising from the combustion of fossil fuels, as in power generation, or from the preparation of fossil fuels, as in natural-gas processing. Capturing CO2 involves separating the CO2 from some other gases. For example in the exhaust gas of a power plant other gases would include nitrogen and water vapor. The CO2 must then be transported to a storage site where it will be stored away from the atmosphere for a long period of time. In order to have a significant effect on atmospheric concentrations of CO2, storage reservoirs would have to be large relative to annual emissions. (IPCC, 2001)

This mitigation option is for Desert Rock Energy Facility and any other proposed power plants to invest into CO_2 emissions control and capture technologies. Desert Rock is in a unique situation to set an example and take the lead in this emissions reduction field.

Desert Rock Energy LLC submitted a set of comments on the Four Corners Air Quality Task Force report during the public comment period including a discussion of CO2 emissions. The comments are located in an appendix at the end of the Power Plants section.

Benefits: Reduced CO_2 emissions
Tradeoffs: None
Burdens: CO_2 control technology is expensive. Burden would be on the power plant; however, there may be some funding for the innovative technologies that would be used.

II. Description of how to implement
A. Mandatory or voluntary
Voluntary

Differing Opinion: According to experts, Desert Rock, if built, would be the seventh largest source of greenhouse gas pollution in the Western United States. It is expected that Desert Rock will emit over 11million tons of carbon dioxide per year. Emission controls on carbon dioxide will most likely be required in the very near future. Carbon dioxide emission reduction technology should be mandatory on the Desert Rock facility.

B. Indicate the most appropriate agency(ies) to implement
Environmental Protection Agency (EPA) Region 9 Air Program
Navajo Nation Air Programs
Industry leadership

EPA Climate Protection Partnership is a possible or New Mexico's San Juan Voluntary Innovative Strategies for Today's Air Standards (VISTAS) are possible vehicles for this mitigation option.

III. Feasibility of the option
A. Technical: Technologies exist; many are in the research and development phase. Technological components are commercially ready in unrelated applications (7).

B. Environmental: Capturing and storing CO_2 emissions is difficult. Integrated systems have yet to be constructed at necessary scales. Feasibility question remains whether CO_2 could be stored without substantial leakage over time

C. Economic: Capturing and storing CO_2 emissions can be expensive.

IV. Background data and assumptions used
(1) Desert Rock Energy Project FACT SHEET #1, DEC 2004 (http://www.desertrockenergy.com/)
(2) AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)
(3) Climate Change Advisory Group (CCAG) homepage: http://www.nmclimatechange.us/index.cfm
(4) EPA Climate Protection Partnerships: http://www.epa.gov/cppd/other/energysupply.htm
(5) 4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10
(6) San Juan Generating Station has a total 1798 MW generation capacity, and emits approximately 13,097,000 Tons CO_2/yr. Approx 7,300 Tons CO_2 per MW generation capacity. San Juan Generating Station CO_2 rationing by MW is used as estimation for CO_2 emissions from Desert Rock Energy Facility. Based on this assumption, the CO_2 emissions from Desert Rock Energy Facility will be approximately 11,000,000 Tons/yr.
(7) Scientific American, September 2006 article, "What to do about Coal," pp. 68-75

V. Any uncertainty associated with the option High

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups None

Mitigation Option: Federal Land Manager Mitigation Agreement with Desert Rock Energy Facility

I. Description of option

Background

Sithe Global Energy (Sithe) is proposing the Desert Rocky Energy Facility (DREF) on the Navajo Nation in northwestern New Mexico. The proposed facility would be within 300 km of 27 National Park Service units, nine of which are Class I areas, and six are U.S. Forest Service Class I areas. The proposed facility will have two 750 megawatt pulverized-coal boilers, and would be well-controlled for a coal-fired power plant. SO2 emissions would be controlled to 3,315 tons per year with Wet Limestone Scrubbers, and NOx emissions would be controlled to 3,315 tons per year with Low-NOx burners and Selective Catalytic Reduction. Despite these controls, the National Park Service and U.S. Forest Service have concluded that the emissions from DREF, absent mitigation measures, would have an adverse impact on visibility at four or more Class I areas in the region. There are also concerns with the emissions contributing to cumulative negative impacts in the region as a whole.

The permitting authority for the Desert Rock Energy Facility is the Environmental Protection Agency (EPA) Region 9, because the facility would be located on the Navajo Reservation, where neither the State of New Mexico (or Arizona) nor the Navajo Nation have permitting authority. For over two years, the National Park Service and the U.S. Forest Service worked closely with Sithe, EPA and tribal representatives to ensure the potential impact of the proposed facility were carefully analyzed. When it became evident that emissions from the facility could adversely impact visibility in several Class I areas, the energy company suggested mitigation measures intended to produce a net environmental improvement in the area, notwithstanding construction and operation of the DREF. Sithe and the federal land managers (FLMs) both sought to avoid a formal adverse impact determination that would jeopardize the issuance of the air quality permit. Negotiations ensued and resulted in an agreement in principle on substantive mitigation measures in April of 2006.

In July, 2006, EPA issued a proposed PSD permit for the facility but did not include the agreed-upon mitigation measures. EPA reasoned that mitigation measures should not be included as part of the permit absent a formal declaration of adverse impact by the FLM.
Both the National Park Service and the U.S. Forest Service have asked EPA to include the mitigation measures in the PSD permit. In the absence of the terms of the agreement in principle included as part of the final PSD permit, Task Force members are interested in ensuring the measures will be put in place to avoid adverse impacts to air quality related values in Class I areas and the region as a whole will be avoided throughout the life of the facility.

Sulfur Dioxide Mitigation

The following options outline the sulfur dioxide mitigation strategy for the DREF. The choice between Option A or Option B shall be made by Sithe or its assigns prior to the commencement of DREF plant operations.

Option A: For the purposes of mitigating potential air quality impacts, including potential visibility and acid deposition impacts, of the DREF at Class I and Class II air quality areas in the region potentially affected by DREF, Sithe[1] shall develop or cause to be developed a capital investment project or projects that generate Emission Reduction Credits from physical and/or operational changes that result in real emission reductions at one or more Electric Generating Units[2] (EGUs) within 300 km of the DREF and retire sulfur dioxide[3] Allowances in accordance with the following:

- The number of sulfur dioxide Emission Reduction Credits required for the respective calendar year shall be determined by DREF's actual sulfur dioxide emissions, in tons, plus 10%, measured as set forth in the next paragraph below.
- The amount of Emission Reduction Credits achieved would be determined by comparing the emission rate (in tons) during the year for which the reduction is claimed to a baseline emission rate. The baseline emission rate shall be the average emission rate (in tons per year) during the two-year period prior to any emission reduction taking place.
- Acceptable sulfur dioxide Emission Reduction Credits under this condition shall be allowances originating from facilities that were allocated sulfur dioxide Allowances under 40 CFR 73[4] and that are located within 300 km of the DREF facility.
- The vintage year of the Emission Reduction Credits shall correspond to the year that is being mitigated. Sithe shall retire the required Emission Reduction Credits by transferring an equivalent number of Allowances into account #XXX with the U.S. EPA Clean Air Markets Division[5]. Except for Sithe's purposes under Title IV, these retired Allowances can never be used by any source to meet any compliance requirements under the Clean Air Act, State Implementation Plan, Federal Implementation Plan, Best Available Retrofit Technology requirements, or to "net-out" of PSD. However, surplus Emission Reduction Credits could be used at the discretion of the holder of the credits.
- Sithe shall submit a report to the EPA Region 9 Administrator (or another party acceptable to the Federal Land Managers) no later than 30 days after the end of each calendar year which shall contain the amount of sulfur dioxide emitted; amount, facility, location of facility, vintage of Emission Reduction Credits retired; proof that Emission Reduction Credits/Allowances have been transferred into account #XXX; and any applicable serial or other identification associated with the retired Emission Reduction Credits/Allowances.

Due to the actual emission reductions obtained from nearby sources under this Option, the Federal Land Managers prefer this approach to mitigating DREF's air quality impacts.

Or,

Option B: For the purposes of mitigating potential air quality impacts, including potential visibility and acid deposition impacts, of the DREF at Class I and Class II air quality areas in the region potentially affected by DREF, Sithe shall obtain and retire sulfur dioxide "Mitigation Allowances" from one or more EGUs within 300 km of the DREF in accordance with the following:

- In addition to those Allowances required under Title IV, the required number of sulfur dioxide "Mitigation Allowances" for the respective calendar year shall equal DREF's actual total sulfur dioxide emissions, in tons.
- Acceptable sulfur dioxide "Mitigation Allowances" under this condition shall be from facilities that were allocated sulfur dioxide Allowances under 40 CFR 73 and that are located within 300 km of the DREF. However, the total annual cost of "Mitigation Allowances" purchased beyond those regular Allowances required by Title IV is not to exceed three million dollars[6]. Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining emission reductions, Sithe may obtain physical emission reductions at sources not granted allowances under 40 CFR 73.
- The vintage year of the "Mitigation Allowances" shall correspond to the year that is being mitigated. Sithe shall retire these "Mitigation Allowances" by transferring them into account #XXX with the U.S. EPA Clean Air Markets Division. These retired "Mitigation Allowances" beyond Title IV can never be used by any source to meet any compliance requirements under the Clean Air Act, State Implementation Plan, Federal Implementation Plan, Best Available Retrofit Technology requirements, or to "net-out" of PSD.

- Sithe shall submit a report to the EPA Region 9 Administrator (or another party subject to approval of the Federal Land Managers) no later than 30 days after the end of each calendar year which shall contain the amount of sulfur dioxide emitted from the DREF; amount, facility, location of facility, vintage of Allowances retired; proof that Allowances have been transferred into account #XXX; and any applicable serial or other identification associated with the retired Allowances.

Additional Air Quality Mitigation
If Sithe chooses Option A, it will contribute $300,000 annually toward environmental improvement projects that would benefit the area affected by emissions from DREF, including the Class I areas and the Navajo Nation. If Sithe chooses Option B, it will contribute toward environmental improvement projects an amount equal to the $3 million cap described under Option B above, minus the cost of the Mitigation Allowances, up to a maximum of $300,000. Appropriate projects will be determined jointly by the Federal Land Managers, Navajo Nation EPA, the Desert Rock Project Company and Diné Power Authority, and may include projects that would reduce or prevent air pollution or greenhouse gases, purchasing and retiring additional emission reduction credits or allowances, or other studies that would provide a foundation for air quality management programs. Up to 1/5 of the contributions can be dedicated to air quality management programs. The remaining contributions shall be used to support projects that mitigate greenhouse gas emissions or criteria pollutants impacts. The Desert Rock Project Company shall have the ability to bank the emission reduction credits achieved through these projects and be entitled to these credits to comply with future greenhouse gas emission mitigation programs. Mitigation and contributions toward environmental improvement projects shall not occur before operation of the Desert Rock Energy project begins.

And,

Sithe will reduce mercury emissions by a minimum of 80% on an annual average using the air pollution control technologies as proposed in the permit application, i.e. SCR, wet FGD, hydrated lime injection, and baghouse. In addition, Sithe will raise the mercury control efficiency to a minimum of 90% provided that the incremental cost effectiveness of the additional controls (such as activated carbon injection or other mercury control technologies) does not exceed $13,000/lb of incremental mercury removed. Compliance with this provision will be determined by installation and operation of an EPA-approved mercury monitoring and/or testing program. In operating periods when a minimum of 80% mercury control (or 90% as noted above) is not technically feasible due to extreme low mercury concentrations in the burned coal, Sithe will work with EPA to establish a stack mercury emission limit in lieu of a percent reduction, for the purposes of demonstrating compliance.

Examples of Mitigation Strategies

Example #1:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option A, Sithe would be required to reduce SO_2 emissions at another source (or sources) within 300 km by 3,300 tons. These credits can be used to meet the requirements of the acid rain program under Title IV of the Federal Clean Air Act provided that the physical and/or operational change occur on one or more EGUs.

Example #2:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option A, suppose Sithe reduces SO_2 emissions at another source (or sources) within 300 km by 4,000 tons. In this case, Sithe would have created 700 tons of surplus SO_2 Emission Reduction Credits that it may use as it sees fit.

Example #3:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option B, Sithe would purchase its “regular” 3,000 tons of Title IV Allowances from any source, anywhere, plus up to 3,000 tons of SO_2 “Mitigation Allowances” from another source (or sources) within 300 km, provided that the total cost of the “Mitigation Allowances” does not exceed $3 million (in 2006 dollars). If each “Mitigation Allowance” costs at least $1,000, Sithe would be done.

Example #4:
Suppose DREF emits 3,000 tons of SO_2 in 2010. Under Option B, Sithe would purchase its “regular” 3,000 tons of Title IV Allowances from one or more EGU sources. For the remaining 3000 SO2 “Mitigation Allowances”, Sithe may choose, as an option, to obtain 9000 NOx emission reduction credits from physical or operational changes of one or more NOx emission sources within 300 km.

Example #5:
Suppose Sithe obtains the necessary SO_2 reductions through a capital investment project (Option A), or purchases SO_2 Mitigation Allowances (Option B) at a cost of $2.7 million or less. Sithe would then contribute the maximum $300,000 to the environmental improvement fund because the total annual costs (allowances plus contribution) would be below the $3 million cap. On the other hand, if the mitigation allowances cost more than $2.7 million, Sithe would contribute the difference between the $3 million cap and the actual cost of the Mitigation Allowances (i.e., if allowance costs equal $2.9 million, the environmental improvement fund contribution would be $100,000).

Implementation
The clearest way for these measures to be implemented would be to include them in the PSD permit. Since EPA Region 9 is the permitting authority in this case, that agency would be responsible for including the measure in the permit. Absent including the measures in the permit, other ways of ensuring the mitigation measure will take place are being explored. The FLMs prefer that the mitigation measures be federally enforceable regardless of the mechanism ultimately used.

III. Feasibility of the option
By agreeing to the mitigation measures, Sithe has implicitly affirmed the feasibility of the measures. Incorporation into a permit is feasible for the permitting authority as long as the measure does not contradict any statutory or regulatory provision.

Background Data and Assumptions
The suggested mitigation measures are taken from the agreement-in-principle between Sithe Global Power and the FLMs. Estimated emissions from DREF come from the draft permit.

V. Any uncertainty associated with the option
The uncertainty in this option involves how stakeholders can be assured the measures will actually happen.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

Citations:
[1] References to Sithe include its subsidiary "Desert Rock Energy Company, LLC" which will be the owner of DREF (referred to herein as the Desert Rock Project Company).
[2] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining emission reductions, Sithe may obtain real emission reductions at sources other than EGUs.

[3] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining and tracking emission reductions, nitrogen oxides reductions may be substituted for sulfur dioxide reductions by a ratio of three tons of nitrogen oxides to one ton of sulfur dioxide.
[4] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining emission reductions, Sithe may obtain physical emission reductions at sources not granted allowances under 40 CFR 73.
[5] Provided that Sithe proposes a method acceptable to the Federal Land Managers for determining and tracking Emission Reduction Credits, Sithe may obtain real emission reductions at sources other than EGUs. Nitrogen oxides reductions may be substituted for sulfur dioxide reductions by a ratio of three tons of nitrogen oxides to one ton of sulfur dioxide.
[6] All costs referenced in this document are base-year 2006 dollars that will be adjusted for inflation by using the consumer price index.

FUTURE POWER PLANTS

Mitigation Option: Integrated Gasification Combined Cycle (IGCC)

I. Description of the mitigation option

Energy related projects in the Greater Four Corners Region (NM, CO, AZ, UT and WY) are expected to continue to grow at or above current rates. Population and related commerce growth in the 12 county local Four Corners Region (NM, CO, AZ, UT) grew at a brisk rate of 23.8% during the 1990s (1). Future electric power demand will require new power plants and transmission grid capacities. Alternative future "clean coal" power generation technologies such as, FutureGen, Integrated Gasification Combined Cycle (IGCC), and advanced fossil fuel power plants (with carbon capture and sequestration (CCS) technologies) and renewable energy facilities (e.g., wind farms, solar arrays, …) will be needed to accommodate this growth, as well as the increasing demand outside the Four Corners area. Given the size of the western coal reserve and its relatively inexpensive cost compared to natural gas, commercial IGCC power plants could potentially play a role in meeting the region's future "clean" power needs.

Overview: A power plant based on IGCCtechnology combines or integrates a coal gasification system (gasifier and gas clean-up systems) with a highly efficient combined cycle power generation system. There are a variety of coal gasification technologies in various stages of development that are designed to produce clean synthesis gas (syngas) from coal. The combined cycle unit includes a gas turbine set consisting of a compressor, burner and the gas turbine coupled with a heat recovery steam generator (HRSG). The steam generated in the HRSG, as well as any excess steam generated in the gasification process that is not used elsewhere in the system, is used to power a steam turbine. An IGCC unit has the potential to achieve similar environmental benefits and thermal performance as a natural gas fired combined cycle power generation unit. The use of relatively low cost coal as a feedstock is the one of the main advantages of coal-based power plants. The ability of an IGCC unit to use coal while generating lower air emissions than conventional coal technologies has lead to increased interest in the technology. While IGCC is a promising technology, it has not completely commercially developed. Two small 260 MWe IGCC plants, the Wabash River Plant in Indiana and the Polk Plant in Florida, have been operating for over a decade. Originally built as demonstration plants, reliability of the IGCC units has generally improved over time with gasifier capacity factors in the range of 80% demonstrated in a number of years (2). (Note: the Polk Power Station IGCC unit has only had one year of operation where the gasifier CF was greater than 80% and two years where the CF was near 80% in the 10+ years of operation.) Currently there are at least five separate permit applications for commercial size IGCC plants in the continental United States. Four of these applications are for plants exceeding 600 MWe nominal capacity.

The operation of the major chemical and mechanical process components of a typical coal based IGCC power plant can be summarized as follows (3):

- The gasifier produces syngas by partially oxidizing coal in presence of air or oxygen.
- The ash in the coal is converted to inert, glassy slag.
- The syngas produced from the gasifier is cooled.
- The syngas is cleaned to remove particles.
- The slag and other inert material are collected to be used to make some products or can be safely discarded in the landfill.
- The mercury is removed by passing syngas through the bed of activated carbon.
- The sulfur removed from the syngas is converted into elemental sulfur or sulfuric acid for sale to chemical or fertilizer companies.
- The clean syngas can either be burned in a combustion turbine/electric generator to produce electricity or used as a feedstock for other marketable chemical products.

- Steam produced in the HRSG from the hot combustion turbine exhaust, as well as additional steam that has been generated throughout the process, drives a steam turbine to produce additional electricity.
- The stream exhausted from the steam turbine is cooled and condensed back to water. The water is then pumped back into the steam generation cycle.

Benefits:

- For traditional pollutants such as nitrogen oxides (NOx), sulfur dioxide (SO_2), particulate matter (PM) and mercury (Hg), IGCC is lower polluting than the current generation of traditional coal-fired power plants. It is potentially as "clean" a NOx emitter (< 0.3 lb/MW-hr) as for NGCC plants (4).
- The removal of sulfur compounds, particulates and mercury is more efficient in an IGCC because the removal can take place before the gas is burned (fuel gas) instead of removing the compounds from the exhaust gases following combustion (flue gas).
- The water requirement for the IGCC process is approximately one-third less than that of a pulverized coal plant.
- Solid waste generation at an IGCC power plant is less than that of a PC plant.
- IGCC plants are more flexible in terms of fuel feedstock because they can utilize a variety of fuels, such as coal, biomass, and refinery by-products such as petroleum coke (petcoke). In general, IGCC units are designed to use only one type of coal (i.e. bituminous, sub-bituminous or lignite), but can handle a variety of coals from within the same coal type.
- The CO_2 emissions from an IGCC unit can be higher than from a conventional coal power plant (3). However, based on current technology, it is believed that capture of CO_2 emissions from IGCC plants would be more energy efficient than capture from a conventional coal fired power plant.
- IGCC plants operate at efficiencies of about 40% but have the potential to be as high as 45% (or higher if fuel cells are used). By comparison, conventional combustion-based power plants have efficiencies that range from about 33% to 43%.

Burdens (or deployment barriers):

- General lack of commercial-scale operating experience, especially at Four Corners altitudes.
- Doubts about plant financial viability without subsidies. IGCC has significantly higher capital costs, nominally approximately 20% or higher than the cost for conventional PC plants (Wayland, 2006).
- Low plant reliability, demonstration of commercial plant reliability and capacity factor remains a concern.
- Without carbon capture, an IGCC can have a higher carbon footprint compared to a conventional PC plant. However, the lower total gas flow, the higher percentage of CO_2 in the gas stream, combined with the high operating pressure of the gas stream, makes it easier to recover CO_2 from the syngas in IGCC power plants than from flue gas in conventional coal power plants, based on current technology.
- IGCC carbon capture and sequestration (CCS) technologies have not yet been demonstrated at commercial scale. However, once CCS is demonstrated, IGCC has a potential advantage in capturing and sequestrating CO_2 at lower costs for the reasons stated in the bullet above.

II. Description of how to implement

A. Mandatory or voluntary

Voluntary to look at IGCC as a future clean power generation option for future power plants in the Four Corners area.

B. Indicate the most appropriate agency(ies) to implement

Policy options for use of Integrated Gasification Combined Cycle Technology could be developed by Environmental Protection Agency (EPA), Department on Energy (DOE), State or Tribal Environmental Protection Agencies.

III. Feasibility of the option

A. Technical: There is some concern about the feasibility of IGCC power plants at high altitude, elevated temperatures and using western fuels. High altitudes and elevated temperatures lead to significant derations of the power output from the gas turbine portion of the IGCC unit. Turbine manufacturers are working on ways to overcome this altitude deration but, to-date, no solutions have been developed and/or demonstrated.

Carbon dioxide capture technology from IGCC units is still in its research and development phase. To be more cost competitive, a number of technology improvements will need to be made in IGCC plant design; including larger, higher pressure and lower cost quench gasifiers (6). In addition, new and improved gas turbines will be needed that enable air extraction across the operating range of ambient temperatures and with hydrogen firing (7).

Carbon capture and sequestration technologies have potential to substantially reduce carbon emissions into the atmosphere. However the given the current cost of carbon capture and sequestration technologies, it will not be viable solution without a carbon penalty. CO_2 sequestration is also a site-specific geological issue. Options to address this issue include:

- Locating the IGCC unit in an area suitable for geologic sequestration, EOR, EGR or ECBMR
- Pipe the captured CO_2 from an IGCC unit to an area suitable for geologic sequestration, EOR, EGR or ECBMR
- Gasify the coal close to an area suitable for geologic sequestration, EOR, EGR or ECBMR and then send the gas for the power production (although this option does not receive the efficiency benefits associated with a fully integrated IGCC unit).

Currently in the US there are two small IGCC plants, the Tampa Electric Polk Power Station in Florida and the Wabash River Coal Gasification Repowering Plant in Indiana, using coal to make electric power as the primary product. These plants were funded and built in the mid-1990s as demonstration plants by DOE. Recently, however, five companies have applied for and in few cases already received permits and at least five companies have announced plans or issued letters of intent to build and operate IGCC facilities in the US. American Electric Power is proposing to build two 629 MW power plants in Ohio and West Virginia – although the projects have been put on hold due to concerns over project cost escalation (as have several other utilities) (8). Xcel Energy is investigating building an IGCC plant with CO_2 capture and sequestration. Duke and Tampa Electric have received tax credits to help reduce the cost of building IGCC power plants under the Energy Policy Act of 2005.

B. Environmental: For traditional pollutants such as NOx, SO_2, PM and Hg, IGCC is inherently lower polluting than the current generation of traditional coal-fired power plants. There are a number of concerns related to the geologic sequestration of CO_2, whether or not the CO_2 is from an IGCC unit. These concerns include, but not limited to the following:

- How will geologic sequestration be permitted over the long-term, including demonstration studies and the duration of the sequestration permit (i.e. 5 year, life of facility, etc.)
- What measurement, monitoring and verification (MMV) techniques and requirements will be placed on the project
- How will the liability associated with the sequestered CO_2 be addressed
- How will the property rights associated with the sequestered CO_2 be addressed

- Will the injection of CO_2 into a deep saline aquifer prohibit the future use of water from that aquifer should in-land desalination prove to be cost-effective or necessary to address future water needs

C. Economic: IGCC has higher capital costs than conventional PC plants (9). Historically – and currently, concerns about operational reliability and costs presented issues of uncertainty for IGCC technology and impeded its deployment. IGCC can be a versatile technology and is capable of using a variety of feedstocks. In addition to various coal types, feedstocks can include petroleum coke, biomass and solid waste.

Along with electricity production, IGCC facilities, if designed to do so, can co-produce other commercially desirable products. Some of these products include steam, oxygen, hydrogen, fertilizer feed stocks and Fischer-Tropsch fuels (10).

There is not a consensus about the relative costs of carbon capture technology for various plants. General consensus is that, given current technology, it is less expensive to capture CO2 from IGCC plants than from any other coal-based plant, as well as NGCC plants (11). According to an MIT study, today the capital cost (in 1999 dollars?) of CO_2 capture and separation is $1730/kW, which will reduce to $1433/kW in 2012. The CO_2 capture and separation cost for a NGCC power plant is about $1120/kW today, which will reduce to $956/kW in 2012 (12). There are many uncertainties with regards to the costs of CCS.

The operational versatility noted above for IGCC technology may mitigate the risk of higher costs. In addition, under the Energy Policy Act of 2005, there are provisions for tax credits and a DOE Loan Guarantee Program to provide incentives to facilitate the deployment of IGCC technology.

IV. Background data and assumptions used:

(1) City of Farmington Draft Consolidated Plan, 2004, June
(2) Coal-Based IGCC Plants – Recent Operating Experience and Lessons Learned. Gasification Technologies Conference, Washington, DC (October 2006).
(3) Pioneering Gasification Plants (DOE): http://www.fe.doe.gov/programs/powersystems/gasification/gasificationpioneer.html
(4) Wayland, R.J., 2006, U.S. EPA's Clean Air Gasification Activities, Gasification Technologies Council, Winter Meeting January 26, Tucson, Arizona
(5) Blankinship, Steve. "Amid All the IGCC Talk, PC Remain the Go-To Guy." Power Engineering International.
(6) Revis, James, 2007, Clean Coal Technology Status: CO_2 Capture & Storage *Technology Briefing for COLORADO RURAL ELECTRIC ASSOCIATION, February 19*
(7) Wabash River IGCC Topical Report 2000 - www.fossil.energy.gov/programs/powersystems/publications/Clean_Coal_Topical_Reports/topical20.pdf
(8) American Electric Power permit application for proposed IGCC power plant in Great Bend, Ohio and Mountaineer, West Virginia. http://www.aep.com/about/igcc/technology.htm
(9) Technical Report on the Environmental Footprint and Costs of Coal-Based Integrated Gasification Combined Cycle and Pulverized Coal Technologies, Fact Sheet: http://www.epa.gov/airmarkets/articles/IGCCfactsheet.html
(10) IGCC & CCS Background Document. 2006, State Clean Energy-Environment Technical Forum Integrated Gasification Combined Cycle (IGCC) Background and Technical Issues June 19
(11) Clayton, S.J., Stiegel, G.J., and Wimer, J.G., 2002, Gasification Technologies Product Team U.S. Department of EnergyU.S. DOE's Perspective on Long-Term Market Trends and R&D

Needs in Gasification 5th European Gasification Conference Gasification – The Clean Choice Noordwijk, The Netherlands April 8-10
(12) Herzog, Howard. "An Introduction to CO_2 Separation and Capture Technologies." MIT Energy Laboratory (1999).

<u>V. Any uncertainty associated with the option (Low, Medium, High):</u>
Medium to High, particularly when coupled with CCS as both are developing technologies.

<u>VI. Level of agreement within the work group for this mitigation option</u>: TBD

<u>VII. Cross-over issues to the other source groups:</u> None at this time.

Mitigation Option: Carbon (CO_2) Capture and Sequestration (CCS)

I. Description of the mitigation option

Carbon Capture and Sequestration (CCS) generally consists of removing carbon in the form of CO_2 from either the fuel gas stream; syngas of an Integrated Gasification Combined Cycle (IGCC) power plant or the flue gas stream of other fossil fuel power plants (i.e. pulverized coal, including supercritical pulverized coal (SCPC) and ultra-super critical pulverized coal (USCPC), and natural gas (NGCC) units) compressing and transporting the CO_2 to the sequestration site and sequestering the CO_2. Sequestration can consist of either injecting the CO_2 into a deep saline aquifers or using the CO_2 for enhanced oil recovery (EOR), enhanced natural gas recovery (EGR) or enhanced coal bed methane recovery (ECBMR). Utilization of CCS in combination with other mitigation options such as alternative fuels, energy efficiency and renewal energy would mitigate the potential greenhouse gas (GHG)/climate change impacts of using fossil fuels for power generation.

Overview:

Currently, there are two generic types of CO_2 removal solvents available:

- Chemical absorbents (i.e. amines) that react with the acid gases and require heat to reverse the reactions and release the CO_2
- Physical absorbents (i.e. Selexol and Rectisol) that dissolve CO_2

Amines: Amines are organic compounds that contain nitrogen as the key atom. Structurally, amines resemble ammonia. The advantage of an amine CO_2 removal system is that it has a lower capital cost than any of the current physical solvent processes. The disadvantage is that an amine system uses large amounts of steam heat for solvent regeneration and energy to re-cool the amine, making it a less energy efficient process.

Selexol: Selexol is the trade name for a physical solvent that is a mixture dimethyl ethers of polyethylene glycol. In the Selexol process, the solvent dissolves the CO_2 from the gas stream at a relatively high pressure, generally in the range of 300 – 1,000 psia. The resulting rich solvent can then either be let down in pressure and/or steam stripped to release and recover the CO_2. The Selexol process requires less energy than amine-based processes as long as the operating pressure is above 300 psia. At lower pressures, the amount of CO_2 that is absorbed per volume of solvent drops to a level that generally favors the use of an amine system.

Rectisol: Rectisol is the trade name for a CO_2 removal process that uses chilled methanol. In the process, methanol at a temperature of approximately –40 °F absorbs the CO_2 from the gas stream at a relatively high pressure, generally in the range of 400 – 1,000 psia. The resulting rich solvent can then either be let down in pressure and/or steam stripped to release and recover the CO_2. While the methanol solvent is less expensive than the Selexol solvent, the Rectisol process is more complex, has a higher capital cost and requires costly refrigeration to maintain the low temperatures required. It does, however, provide for the most complete removal of CO_2.

Cryogenic coolers are also currently shown to capture CO2 from the combustion exhaust. The cost of CO2 capture is generally estimated as three fourth of the whole carbon capture, storage, transport, and sequestration system. Currently the average cost of carbon capture is about $150/ton by using current technology is high for carbon emission reduction purposes (1). In order to transport and sequester the CO_2, the gas must be compressed to 2000 psia or higher. Research is underway to find better technologies for carbon capture. Presently, the most likely identifiable options apart from absorbents for the carbon separation and capture are (1):

- Adsorption (Physical and Chemical)
- Low-temperature Distillation
- Gas separation Membranes
- Mineralization and Biomineralization

Benefits:

- CO_2 that would otherwise be emitted to the atmosphere is sequestered.
- If used for Enhanced Oil Recovery (EOR), Enhanced Gas Recovery (EGR) or Enhanced Coal Bed Methane Recovery (ECBMR), the CO_2 from power plants is put to beneficial use and could replace some or all of the natural CO_2 that is currently used for those purposes as well as recover fossil fuel.

Burdens (or deployment barriers):

- Currently there are no power plants in the world that perform CCS, so the integration of the power plant technology with the CCS technology has yet to be proven.
- The capital and O&M costs for CCS are significant and adversely impact the cost of electricity (COE). The cost of electricity will increase by 2.5 cents to 4 cents/Kwh if current carbon capture technologies are added to electrical generation(1).
- No large-scale tests of deep saline aquifer injection have been performed to-date. The Sleipner project in Norway's North Sea is the world's first commercial carbon dioxide capture and storage project(2). CO2 is extracted from gas production on Statoil's Sleipner West Field in the Norwegian North Sea. Started in 1996, it sequesters about 2800 tons of carbon dioxide each day and injects into Utsira sandstone formation (aquifier)(3).
- No environmental laws, rules or procedures are in place for CCS projects.

<u>II. Description of how to implement</u>

<u>A. Mandatory or voluntary</u>

Voluntary in the near term; mandatory as laws, rules and procedures are established.

<u>B. Indicate the most appropriate agency(ies) to implement</u>

Environmental Protection Agency (EPA), Department on Energy (DOE), State Environmental Protection Agencies.

III. <u>Feasibility of the option</u>

A. <u>Technical</u>:

<u>IGCC</u>

In IGCC power plants, CO_2 can be captured from the synthesis gas after the gasification process before it is mixed with air in a combustion turbine. The CO_2 is relatively concentrated (50 volume %) and at high pressure which provides the opportunity for lower cost for carbon capture (4).
While proven carbon capture technology is available for IGCC plants, there are currently no IGCC facilities in the world that capture, compress and sequester CO_2. Depending on the IGCC technology and the carbon capture technology used, it is estimated that carbon capture and compression could add 35 - 50% to the capital cost of the plant and the cost of electricity. These costs do not include the costs for installation of wells and/or pipelines for sequestration of the captured and compressed CO_2, both from a demonstration (pre-permitting) and ongoing operations perspective.

A number of IGCC technology vendors are working on improvements to their gasifiers that allow for easier CO_2 capture at reduced capital and O&M cost. In addition, a number of firms are working on improved CO_2 capture systems, with most efforts in the area of enhanced or advanced amine systems. It is too early in the development process to verify or quantify the potential cost and performance benefits of these new design efforts.

Another concern is the fact that there is currently no large combustion turbine commercially available that is capable of burning the hydrogen rich gas that would result from an IGCC plant with CCS.

SCPC/USCPC

While proven carbon capture technology is available for SCPC/USCPC plants (currently limited to amine systems), there are currently no SCPC/USCPC facilities in the world that perform CCS. Depending on the carbon capture technology used, it is estimated that carbon capture and compression could add 65 - 100% to the capital cost of the plant and the cost of electricity. These costs do not include the costs for installation of wells and/or pipelines for sequestration of the captured and compressed CO_2.

A number of projects are currently underway to try to improve the capture of CO_2 from SCPC/USCPC units in terms of removal efficiency and capital and O&M expenditures. Generally, these projects are targeting 90% capture of CO_2, although there is a general belief that the optimal/achievable reduction level will be less. EPRI and Alstom are working on a chilled ammonia (chemical absorbent) system. A 5 MW slipstream chilled ammonia pilot system will go into operation in Wisconsin in the fall of 2007. According to EPRI, the goal for the project is to reduce the cost for CO2 capture and compression by approximately 66% versus the cost of conventional amine systems. While the exact costs and efficiency gains of the chilled ammonia system are not known at this time, it is known that the system efficiency will decrease in warmer climates.

Babcock & Wilcox (B&W) is currently working on a design for a 500 MW oxygen fired, recirculating gas stream (oxy-fired) boiler for Sask Power in Canada. This unit would use oxygen from an air separation unit (ASU) instead of air for combustion. This use of oxygen means that less NOx is formed (approximately 65% less) in the combustion process and that the resulting flue gas is mainly CO_2 (up to approximately 80%). The flue gas stream, after removal of particulates, SO_2 and moisture, would be recirculated through the boiler, removing a portion (20 - 35%) of the CO_2 with each pass. B&W expects to start testing the design at their 30 MW Clean Environment Development Facility (CEDF) in Alliance, Ohio in June of 2007. Net power output before CCS from the 500 MW unit is expected to be on the order of 350 MW. Additional power will be required to compress and sequester the captured CO_2.

In addition, a number of vendors are working on enhanced/advanced amine systems that they believe will outperform current amine systems.

NGCC

While carbon capture technology is available for NGCC plants (currently limited to amine systems), there are currently no NGCC facilities in the world that perform CCS. Depending on the carbon capture technology used, it is estimated that carbon capture and compression could add 40 - 80% to the capital cost of the plant and the cost of electricity. These costs do not include the costs for installation of wells and/or pipelines for sequestration of the captured and compressed CO_2.

B. Environmental: There are currently no environmental laws, rules or procedures in place for CCS projects. Issues that need to be addressed include, but are not limited to:

- How will geologic sequestration be permitted over the long-term, including demonstration studies and the duration of the sequestration permit (i.e. 5 year, life of facility, etc.)
- What measurement, monitoring and verification (MMV) techniques and requirements will be placed on the project
- How will the liability associated with the sequestered CO_2 be addressed
- How will the property rights issues associated with the sequestered CO_2 be addressed
- Will the injection of CO_2 into a deep saline aquifer prohibit the future use of water from that aquifer should in-land desalination prove to be cost-effective or necessary to address future water needs

C. Economic: The capital and O&M impacts of CCS are significant and will result in substantial increases in the cost of electricity.

IV. Background data and assumptions used:

1) Carbon Capture Research. U.S. Department of Energy <http://www.fossil.energy.gov/programs/sequestration/capture/>

2)Carbon Capture and Sequestration Technologies, MIT. <http://sequestration.mit.edu/>

3) Carbon Dioxide storage prized. STATOIL. <http://www.statoil.com/statoilcom/SVG00990.NSF?OpenDatabase&artid=01A5A730136900A3412569B90069E947>

4) Carbon Sequestration. National Energy Technology Laboratory. <http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html>

V. Any uncertainty associated with the option (Low, Medium, High)

High, as the integration of power generation and CCS is a developing and undemonstrated technology and there are currently no laws, rules and procedures are established to address CCS.

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other source groups: None at this time.

Mitigation Option: Negotiated Agreements in Prevention of Significant Deterioration (PSD) Permits

I. Description of option

Summary of Option

Agreements regarding mitigation of air quality and air quality related value impacts negotiated between PSD permit applicants and parties other than the permitting authority should be incorporated into the PSD permit and made federally enforceable. If the other party is a federal land manager, there should not have to be a formal declaration of adverse impact before the agreement is made part of the permit.

Background

A primary goal of the PSD program is to protect air quality and air quality related values in areas that attain the National Ambient Air Quality Standards, specifically certain National Parks and Wilderness areas (i.e., "Class I" areas). If representatives of a proposed new source are willing to mitigate the predicted impacts of the new facility, then the permitting authority should honor this intent to reduce air pollution impacts at Class I areas by including mitigation measures in a PSD permit.

This issue arose in the context of federal land manager (FLM) review of the Desert Rock Energy Facility permit application. Federal land managers responsible for "Class I" areas are responsible for reviewing PSD permit applications for new sources to determine if that source would cause or contribute to an adverse impact on visibility or other air quality related values. In the immediate Four Corners area, Mesa Verde National Park and Wemminuche Wilderness Area are the closest Class I areas, and would be impacted the greatest by the Desert Rock Energy Facility. However, there are a total of 15 Class I areas that could be impacted by the facility.

Typically, FLMs address potential adverse impacts through consultation with the permit applicant and permitting authority before the permit is proposed, and before any formal adverse impact finding. When it becomes apparent through the modeling analysis that a facility *may* have an adverse impact, applicants are generally willing, and actually prefer, to discuss changes to address those adverse impacts, through tightening down the control technology, obtaining emission offsets, or other methods. State permitting agencies have generally incorporated the agreed-upon mitigation measures directly into the PSD permit, which as a practical matter, makes those agreements enforceable. This process allows for consultation in the case of suspected adverse impacts and avoids delays in permitting or denial of a permit, which may result from a formal finding of adverse impact.

The permitting authority for the Desert Rock Energy Facility is the Environmental Protection Agency (EPA) Region 9, because the facility would be located on the Navajo Reservation, where neither the State of New Mexico (or Arizona) nor the Navajo Nation have permitting authority. For over two years, the National Park Service and the U.S. Forest Service worked closely with Desert Rock representatives, EPA and tribal representatives to ensure the potential impact of the proposed facility were carefully analyzed. When it became evident that emissions from the facility could adversely impact visibility in several Class I areas, the energy company suggested mitigation measures intended to produce a net environmental improvement in the area, notwithstanding construction and operation of the Desert Rocky Energy Facility. Negotiations ensued and resulted in an agreement in principle on substantive mitigation measures in April of 2006. In July, 2006, EPA issued a proposed PSD permit for the facility but did not include the agreed-upon mitigation measures. EPA reasoned that mitigation measures should not be included as part of the permit absent a formal declaration of adverse impact by the FLM.

Without the terms of the agreement in principle included as part of the PSD permit, there is no mutually acceptable way to ensure the specific mitigation measures will be enforceable, and therefore, no assurance that adverse impacts to air quality related values in Class I areas will be avoided throughout the life of the facility.

It is unacceptable that the EPA, in July 2006, issued a proposed PSD permit for the facility but did not include the agreed upon visibility mitigation measures. The so called brown curtain of “regional haze” already present which blankets the Four Corners Area blocks visibility. Not only is it ugly, it indicates degradation of the air quality. Visibility mitigation must be enforceable; therefore, visibility measures must be included in the permitting of Desert Rock and any other future coal fired power plants in the Four Corners Area.

II. Description of how to implement

The permitting authority for a given facility would be responsible for including any agreed-upon mitigation measures into a PSD permit. Usually the permitting authority is the state agency responsible for air pollution control; in some cases, however, the EPA is the permitting authority.

Regarding the actual negotiation of any mitigation measures, information regarding the mitigation measure and its effects is exchanged in the permitting process. In some instances the applicant may supply additional information in the form of an air quality modeling analysis and/or control technology analysis to demonstrate to the FLM the effectiveness of the mitigation measures in reducing impacts to AQRVs at the Class I area(s) in question.

III. Feasibility of the option

By agreeing to a mitigation measure, a permit applicant has implicitly affirmed the feasibility of the measure. Incorporation into a permit is feasible for the permitting authority as long as the measure does not contradict any statutory or regulatory provision.

IV. Background data and assumptions used

The PSD program is created at 42 U.S.C. §§7470-7492; implementing regulations are codified at 40 C.F.R. §51.166 and 40 C.F.R. §52.21.

V. Any uncertainty associated with the option

No uncertainties known.

VI. Level of agreement within the work group for this mitigation option

To Be Determined

VII. Cross-over issues to the other Task Force work groups

None

Mitigation Option: Clean Coal Technology Public Education Program

I. Description of the mitigation option

The goal of this option is to educate all stakeholders, particularly the wider public, as to the cost/benefits of the latest clean coal technology during the permitting process for new coal based power generation facilities in the Four Corners. The public who then participates in the hearings and other steps of the permitting process, would be educated and know the pros and cons of the various technological options available to those proposing the project.

According to the Department of Energy, coal will continue indefinitely to be one of the least expensive sources of electric power in the United States. The Four Corners region has abundant coal resources and many stakeholders who wish to capitalize on that abundance to produce energy, jobs and revenue. Technologies for transforming coal to energy vary enormously in cost, and pollution, including release of global warming gases. Research into improved (cleaner) technologies continues, see President Bush’s new commitment to the Clean Coal Power Initiative as one example. The public in the Four Corners area needs to be informed and frequently updated as to the status of research and testing in clean coal technology so they can ask educated questions and make educated political decisions and/or demands on policy-makers in the agencies permitting power generation installations in the Four Corners area. This mitigation option lays out a plan for the on-going education of Four Corners stakeholders with regard to the latest, cleanest, safest technologies for converting our generous resource into energy.

This option would require the primary permitting agency for a proposed project to designate early in the process a non-political ‘clean coal technology scientist/advocate’ whose responsibility it would be to prepare documentation in layman’s terms on the latest research and feasibility of clean coal technology and where the proposed technology stands in relation to the current ideal. This individual would make presentations at hearings, be available by phone/internet for consultation with stakeholders, including the media, submit factual information pieces to the Four Corners media on clean coal technology, speak at community meetings, etc. In other words, the scientist/advocate would design and conduct an extensive public relations campaign to education the public during the permitting process.

Many institutions, including the Department of Energy, and educational institutions, conduct research in clean coal technology on an ongoing basis and NGOs like San Juan Citizens Alliance make themselves experts on the issues and could be called upon to educate the public at any given point. The obstacle here is how to ensure that the latest knowledge reaches the lay public when they can use it during the permitting process of new coal-based power plants and/or updates of older units. One way is to tie public education into the EPA permitting process. (Other ideas are welcome.) This option places an additional burden on the EPA in time, energy and cost and therefore indirectly on those proposing the new or updated power plants on to whom the additional costs of this step would be passed.

Participation of an educated public in the permitting process will lead to better long-term decision-making for the Four Corners area.

II. Description of how to implement

A. Mandatory or voluntary:
Mandatory

B. Indicate the most appropriate agency(ies) to implement:

The lead permitting agency, typically the EPA. The Department of Energy might be another appropriate agency; however, it is hard to envision how they could be motivated enough to know when and where their expertise is needed if not tied to the permitting process.

EPA is strongly encouraging companies proposing to build to power plants to meet with the local citizens in nearby communities and regional areas to discuss their plans including their projected emissions if the facility has been announced. In addition, if they are constructing near a non-attainment area for any pollutant, EPA believes it is important to meet with local air planning officials in the non-attainment area. The companies need to be willing to lay everything on the table with respect to technology, emissions, and comparisons to other similar facilities nationwide. The companies are better off actually doing these types of meetings before they even send in the permit application. Oftentimes, people are not opposed to a new cleaner EGU, but they want something done about those older existing units in the area. This hopefully will help educate the community on what the company would like to construct.

Remember once the permitting application arrives and the State proposes the permit for public comment.....some State regulatory requirements may require them to treat any meeting where comments are made about the facility's proposed permit and technology into the public record. Therefore, it would be encouraged that any meetings with the community to occur prior to the permit being public noticed.

Another option for sponsoring a Clean Coal meeting in the 4 Corners area is to invite speakers from Dept. of Energy, EPA, National Labs doing coal related work, and State permitting officials. It would also be okay to invite independent experts. Obviously, the issue becomes funding for such a meeting. Generally, a DOE and/or EPA rep will not cost you anything. Many technology vendors know the clean coal technology in depth and would participate.

Another option is to talk to state Air Quality Bureau chief about applying for special projects funds from EPA to host such an event in the future. It is not certain what type of funds DOE may have available, but they may have funding for such a meeting as well. Another option is for a company to fund as part of an enforcement settlement agreement, or for a consortium of the mining companies and power utilities to fund the meeting location, but the State to do all of the planning and agenda development for the meeting.

It would be strongly encouraged that the state environment department go through the actual permitting process at any meeting clearly showing in a process flowchart the specific points for public comment opportunities since it would be the state process that they would be following. The state environment department also needs to educate the public on the types of comments that actually are considered valid or significant comments.....(examples are great) versus the general "not in my backyard" comments.

Options for on funding, implementation, and a CCT public educational program within existing state PSD permitting programs:

- **Establish a federal/state agency MOU**: A memorandum of understanding (MOU) would provide a mechanism for CCT public information transfer during the PSD permit application. It could facilitate the selection of an independent engineer/ scientist on clean coal technology from nearby leading universities such as Colorado School of Mines or from independent national labs such as National Energy Technology Laboratory or from reputable CCT research non-for profit scientific institution such as Union of Concerned Scientists. The engineer/scientist would provide the public with status on CCT research/demonstration/commercialization as well as comparative advantages or disadvantages of these technologies with the proposed power plant technology (e.g., SCPC plant).
- **Develop and maintain a CCT education/information transfer web-portal**: New commercial power generation technological advancement occur over a relatively long time frame. An easily accessible and updatable source of CCT information and educational material can be provided through a web portal. Argonne has developed a variety of energy web portals, many with public

outreach and some with educational elements (http://ocsenergy.anl.gov/, http://www.onlakepartners.org/). A web based outreach platform can provide CCT educational material on demand in layperson language and can provide public outreach tools for more informed and effective public involvement. Advancements in the clean coal technology could be updated on a regular basis. The state permitting agency could assume web-portal maintenance with an option for independent oversight and feedback from CCT experts. These experts (an engineer/scientist) can be retained to further support these efforts in person at public meetings during breakout public CCT education sessions.

III. Feasibility of the option

A. Technical:
Feasible, these people exist in the Four Corners area; Bill Green is an example of one. The Department of Energy undoubtedly could recommend local or regional experts.

B. Environmental:
Not relevant, no impact

C. Economic:
Retaining such a scientist/advocate will cost money but the reasonable expenses for this individual could be passed by the permitting agency to the organizers of the proposed power generation facility

This may require a regulatory and fee changes by state agencies......include a requirement for such a meeting in the State rules including a fee requirement for the permit applicant to fund the meeting location/facility to host such a meeting in the Regional area of the proposed facility. It would need to be researched and discussed to ensure that it's not prohibited by the CAA.

The ideas for funding of clean coal technology education program (within existing state PSD permitting programs):

- To implement such an effective clean coal technology education program a funding mechanism needs to be worked out between states and EPA. Options include but are not limited to:
    - The permitting fee for the power plan can be increased in order to pay for the the public education outreach program (e.g., web-portal and/or CCT expert).
    - Some non-for profit foundation involved in public education can be contacted to obtain a grant to build the webportal as well as pay for the compensation to experts/scientists.
    - It may be possible to find independent experts/scientists who will be able to provide their time for free for public good but there will still be a need of compensation for travel and lodging.

D. Political:
There is likely to be political resistance to spending additional dollars in this way. Additionally, the effort to educate the public on clean coal technology should be on ongoing effort, not dependent on proposal of power plants; however, it is difficult to figure out how to tie such an independent effort to the motivation and funding that it would take to get it to actually happen.

IV. Background data and assumptions used

Assumptions:
1. Coal continues to be abundant in the Four Corners area and in demand in power generation facilities
2. Stakeholders continue to desire to construct power generation facilities in the Four Corners area using coal, as opposed to transporting it out to other areas for use.
3. A standardized cost-effective perfectly clean technology for use of coal in power generation is years away.

V. Any uncertainty associated with the option (Low, Medium, High)

The only uncertainty that exists involves the degree of success the scientist/advocate would have in educating the public given the apathy sometimes exhibited by the public around these issues

VI. Level of agreement within the work group for this mitigation option

VII. Cross-over issues to the other Task Force work groups

Mitigation Option: Utility-Scale Photovoltaic Plants

I. Description of the mitigation option

Future Large-scale photovoltaic power plants (solar energy plants) could be built to accommodate future energy demands and offset some of the current coal-based coal fired power demands

Large-scale Photovoltaic power plants would consist of many PV arrays working together. PV electricity generation does not consume fuel and produces no air or water pollution.

The Electric Power Research Institute (EPRI) announced in July 2007 the beginning of a new project to study the feasibility of concentrating solar power in New Mexico. Unlike conventional flat-plate solar or photovoltaic panels, concentrating solar power (CSP) uses reflectors to concentrate the heat and generate electricity more efficiently. There are four utility-sized CSP plants in the U.S. today; one in Nevada and three in California. Initiated by New Mexico utility PNM and with subsequent interest from other regional utilities, the project will be directed and managed by EPRI. PNM has expressed interest in building a CSP plant in New Mexico by 2010. The feasibility study for a power plant of the 50-500 megawatt (MW) size range is expected to be finished by the end of 2007. The Four Corners area is one of the best areas for solar energy production in the United States and would be an ideal location for a new solar energy plant. For example, in Farmington, NM a flat-plate collector on a fixed-mount facing south at a fixed tilt equal to latitude, sees an avg. of 6.3 hours of full sun. The solar plant could help New Mexico meet renewable energy portfolio standards. San Juan County also has a renewable energy school focusing on solar energy system design and installation. The plant could potentially be an educational/technical resource for the college.

Benefits:

- Utilities can build PV plants much more quickly than they can build conventional fossil or nuclear power plants, because PV arrays are fairly easy to install and connect
- Unlike conventional power plants, modular PV plants can be expanded incrementally as demand increases
- Utilities can build PV power plants where they're most needed in the grid, because siting PV arrays is usually much easier than siting a conventional power plant
- Solar energy is clean energy and uses the sun for fuel.

Tradeoffs:
Burdens:

- Photovoltaic systems produce power only during daylight hours, and their output thus can vary with the weather. Utility planners must therefore treat a PV power plant differently than they would treat a conventional plant.
- Using current utility accounting practices, PV-generated electricity still costs more than electricity generated by conventional plants in most places, and regulatory agencies require most utilities to supply the lowest-cost electricity

II. Description of how to implement

A. Mandatory or voluntary

Mandatory (could be added as part of Renewable Energy Portfolio system)

May become more cost effective and implemented voluntarily as the technology continues to mature and power generation stakeholders see economic advantages to solar power.

B. Indicate the most appropriate agency(ies) to implement

State and Federal Governments can pass legislation requiring larger Renewable Energy Portfolios

III. Feasibility of the option

A. Technical –

PV Technology is available and technically feasible

B. Environmental –

PV systems have little adverse environmental impact

C. Economic –

Cost of PV systems to generate power is still more expensive than conventional fossil-fuels

DOE, the Electric Power Research Institute, and several utilities have formed a joint venture called *Photovoltaics for Utility-Scale Applications* (PVUSA). This project operates three pilot test stations in different parts of the country for utility-scale PV systems. The pilot projects allow utilities to experiment with newly developing PV technologies with little financial risk.

IV. Background data and assumptions used

1. DOE Energy Efficiency and Renewable Energy, Solar Energy Technologies Program http://www1.eere.energy.gov/solar/utility_scale.html

2. PVUSA Solar: a Renewable Ventures Project, http://www.pvusasolar.com/

V. Any uncertainty associated with the option:

VI. Level of agreement within the work group for this mitigation option: To Be Determined.

VII. Cross-over issues to the other Task Force work groups

Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

Mitigation Option: Biomass Power Generation

I. Description of the mitigation option

Power Generation using biomass fuels can potentially reduce net CO_2 emissions and other criteria pollutants from 4 Corners area power generation if displacing traditional coal-fired generation and is an option for future power plants in the area. Power from biomass is a proven commercial electricity generation option in the United States. With about 9,733 megawatts (MW) in 2002 of installed capacity, biomass is the single largest source of non-hydro renewable electricity. [1, 2]

Biomass used for energy purposes includes: Leftover materials from the wood products industry, Wood residues from municipalities and industry, Forest debris and thinnings, Agricultural residues, Fast-growing trees and crops, Animal manures. [2]

An aggressive Renewable Portfolio Standard was set in the 2007 NM legislative session. It includes 20% of power generation from renewables by 2020 (for large utilities) and 10% by 2020 (for rural electric cooperatives).
Biomass may be a necessary part of power generation to meet these standards.

In addition a 2005 executive order outlined Greenhouse Gas Emission Reduction Targets. These included reductions of NM Greenhouse gases to 2000 levels by 2012. Biomass power generation may be an alternative source of energy that can offset some of the CO_2 emissions from fossil fuel-based combustion.

Benefits

Biomass combustion to produce electricity generates negligible Sulfur Dioxide and it has been shown to produce less Nitrogen Oxide emissions than coal-fired combustion. CO_2 is absorbed during biomass growth cycle in photosynthesis and then released during combustion, so the direct combustion of the biomass feedstock can be considered to have a net 0 effect on CO_2 emissions. If the biomass fuel can be planted, matured, and harvested in shorter periods of time compare to the natural growth plants then the recycling of CO_2 in the environment can be reduced to close to one – third.

Other benefits include rural economic growth, increased national energy security, and using waste products that would otherwise have to be disposed. Using biomass fuel to generate electricity will reduce the greenhouse gas methane in the environment because if discarded in the landfill, the decomposition of biomass fuel generates methane.

Tradeoffs

- Land required for growing biomass.
- Higher nitrogen content of biomass fuel can contribute to higher NO_x emission such as in the case of fertilizer used to grow biomass fuel.
- N_2O emissions from fertilizer to grow biomass, if used.
- Energy emissions to grow, collect, and transport biomass fuel to plant
- Vehicle and dust emissions from transport trucks
- Energy emissions to dispose of waste
- The particulate emission from the biomass power generating power plant is a real concern. However the particulate emission can be controlled using readily available PM control technologies.

Burdens

For biomass to be economical as a fuel for electricity, the source of biomass must be located near to where it is used for power generation. This reduces transportation costs — the preferred system has transportation distances less than 100 miles.[3]

II. Description of how to implement

A. Mandatory or voluntary

Voluntary. Biomass may offset some of the coal based power generation.
May be necessary under new Renewable Portfolio Standard requirements for New Mexico & Colorado

B. Indicate the most appropriate agency(ies) to implement

Industry Research and Development, State and Federal Policy Support

III. Feasibility of the option

A. Technical – Biomass power generation is a proven commercial technology. Co-firing with fossil fuels may be the most feasible option at this time

B. Environmental – Biomass power generation has some significant advantages over fossil-fuel power generation. As demonstrated by some of the public hearings and objections to a new 35-megawatt plant, proposed to be built in Estancia, NM by Western Water and Power Production LLC., biomass may be a challenging technology to implement.

C. Economic –

A typical coal-fueled power plant produces power for about \$0.023/kilowatt-hour (kWh). Cofiring inexpensive biomass fuels can reduce this cost to \$0.021/kWh, while the cost of generation would be increased if biomass fuels were obtained at prices at or above the power plant's coal prices. In today's direct-fired biomass power plants, generation costs are about \$0.09/kWh. In the future, advanced technologies such as gasification-based systems could generate power for as little as \$0.05/kWh. For comparison, a new combined-cycle power plant using natural gas can generate electricity for about \$0.04-\$0.05/kWh at fall 2000 gas prices.[3]

IV. Background data and assumptions used

1. US DOE Energy Efficiency and Renewable Energy, Biomass Program
http://www1.eere.energy.gov/biomass/technologies.html

2. EIA RENEWABLE ENERGY 2002,
http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/table5.html]

3. US DOE Energy Efficiency and Renewable Energy, State Energy Alternatives
http://www.eere.energy.gov/states/alternatives/biomass.cfm

4. Electricity From: Biomass
http://powerscorecard.org/tech_detail.cfm?resource_id=1

V. Any uncertainty associated with the option: High.

VI. Level of agreement within the work group for this mitigation option: To Be Determined.

VII. Cross-over issues to the other Task Force work groups

Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

Mitigation Option: Bioenergy Center

I. Description of the mitigation option

Sunflower Electric Power Cooperative is planning a bio-energy center adjacent to their coal fired electric plant in rural Kansas[1].Three new 700 MW units are planned to supplement the existing 360 MW unit. The bioenergy center promises some CO2 mitigation along with energy efficient and low pollution auxiliary business enterprises. The bioenergy center concept involves a feedlot, dairy, anaerobic digester, algae reactor, ethanol plant, biodiesel plant, and the coal plant. Methane, electricity, ethanol, and biodiesel will be produced. The wastes (water, manure, biogas, nitrogen, phosphorus, flue gas, glycerol, CO2, wet distiller's grain, and ammonia) are used for inputs for the processes, rather than being discarded.

The anaerobic digester processes manure to produce methane to power the ethanol plant. The algae reactor consumes CO2 from the coal plant flue gas, and nitrogen and phosphorus from the anaerobic digester. The reactor then produces oil-rich protein for biodiesel production, with the residue used for livestock feed. The ethanol plant will consume corn and grain sorghum, and produce wet-distillers grain for livestock feed.

Locally, there could be variations on this theme. Excess corn fodder biomass, not fed to livestock, could be burned in the power plant. Only the grain is useful in ethanol production with current technology. Livestock could be omitted and the ethanol plant powered with natural gas.

Benefits: Any burned biomass has close to zero net effect on CO2 emissions from the coal fired power plant. Energy efficient businesses produce ethanol and biodiesel for sale. Local economic growth is enhanced, with increased national energy independence. Waste products are recycled that would otherwise have to be disposed.

Tradeoffs:
Land is needed to grow grain crops
Nitrate run-off from needed fertilizer
Ancillary energy usage, and lowering of CO2 net efficiency, to cultivate, harvest, and transport the crop, and remove waste products

II. Description of how to implement

A. Mandatory or voluntary: Voluntary.
It should be more feasible to plan such an adjunct facility at the proposed Desert Rock Power Plant, rather than at the existing power plants. Livestock and grain crops could be expanded at the NAPI, resulting in short transportation distances. Sithe Global is required to provide financing for local environmentally beneficial projects as an offset for tax benefits. This could help fund the feasibility studies for this project and a portion of the construction costs.

B. Indicate the most appropriate agency(ies) to implement
Navajo Nation, San Juan County, State of New Mexico economic development departments

III. Feasibility of the option

A. Technical – Co-firing biomass in coal plants is proven technology. Ethanol plants are being constructed at a rapid pace. There is a local construction company with extensive experience with ethanol plants. Each bio-energy component has been commercialized to some degree, but the challenge is the integration of these components in an energy center.

B. Environmental – VOC emission output from an ethanol plant could be mitigated by vapor capture routed to the power plant, or to a thermal oxidizer. The thermal oxidizer could accommodate vapors from the biodiesel plant. A portion of the power plant and thermal oxidizer CO2 emissions would be mitigated by the algae reactor. Expanded feedlot activities have associated groundwater, ozone layer (methane), and odor impacts.

C. Economic – Detailed economic modeling is needed along with the engineering studies to provide input to a viable business plan. A renewable energy project should attract grant money and gain tax benefits. Labor infrastructure at the Desert Rock construction site could be leveraged to construct, then operate the bio-center.

IV. Background data and assumptions used

1. "Farming for Energy" Sunflower Electric's Bioenergy Center in Kansas – EnergyBiz Magazine, Jan./Feb. 2007 -- www.energycentral.com

2. Kansas Technology Enterprise Corporation -- http://www.ktec.com/index_Flash.htm

3. Four Corners Air Quality Task Force Mitigation Option "Biomass Power Generation"

V. Any uncertainty associated with the option (Low, Medium, High) High

VI. Level of agreement within the work group for this mitigation option To be discussed.

VII. Cross-over issues to the other Task Force work groups

Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

Mitigation Option: Nuclear Option

I. Description of the mitigation option

Nuclear reactor power generation should be considered as a mitigation option. We should not assume that it is too politically controversial for consideration. The mitigation options would lack balance if the taskforce were not to consider a future nuclear power plant. Such a plant would have virtually zero air emissions and global warming impact.

The U.S. Nuclear Regulatory Commission is adding staff to consider up to 30 nuclear units in fiscal 2008. This was motivated by the Energy Policy Act of 2005, which has invigorated the power industry to come forward with new plans. A new NRC office has been created solely for licensing and oversight of new reactor activities, with a current staff of 240. Many of these units will be in the south and southeast, where utilities have prior nuclear experience. NRC has streamlined their processes so standard design certifications will be approved, and the safety design hurdle will not be raised continually. Many of these applications will be active pump/valve cooling designs that meet the stringent safety requirements of standard design certifications.

These designs include the GE AWBR (Advanced Boiler Water Reactor), the Areva EPR (Evolutionary Power Reactor), and the Mitsubishi advanced pressurized water reactor. Bechtel is working on standard, pre-engineered modular designs, so that units can be replicated quickly and cost effectively. Construction time is approximately four to five years. If fifteen units were to be built from now until 2020, there would be a need for 30,000 new high-paying craft jobs. Several utilities are committing to these designs because of the certainty they will be completed on schedule with low risk financing, and their operating experience at similar plants.

There is promise for a family of passive cooling reactors, where gravity/density differences provide equivalent convection cooling protection to electrically powered valves and pumps. These designs would be simpler and less expensive than current active pump designs. Much design work has been done, although there is not currently such a unit in operation. General Electric is offering its ESBWR (Economically Simplified Boiling Water Reactor) and Westinghouse its AP1000, an advanced passive reactor. TVA and Entergy are considering use of this technology. Plants of this type will be among those soon licensed by the NRC.

Nuclear plants have lower maintenance costs (about 1.7 cents per kwh, v.s. 3 - 5 cents for a fossil fuel units). Operating experience has advanced greatly over the 30 years since Three Mile Island, with plants running at 90% capacity -- up from 70% in the 1970s.

Opposition will come from perceived plant safety and spent fuel issues. Regional storage of spent fuel already exists in New Mexico. It is likely that Yucca Mountain will be licensed for long term storage. New Mexico should participate in research for the safe long term storage of spent nuclear fuel. There is strong congressional and public recognition that nuclear power generation should be part of the energy portfolio, along with increased renewables, to address climate change. There is also a 20-30% group that opposes both existing and future nuclear power generation. This level of opposition would also be expected in New Mexico, and must be considered in any political process to license a nuclear plant locally. Worldwide, especially in China and India, there is a very active nuclear buildout in progress. Nuclear power generation is actively expanding worldwide, and about to in the United States.

A realistic approach would keep our options open politically, while closely monitoring the re-emergence of the nuclear industry in the United States over the next 5 – 10 years. We should especially follow the operating experience of the new passive cooling reactors which should be on-line in less than ten years.

New Mexico is already in an area of low seismic activity. The additional safety advantage of a passive reactor design should lower public opposition significantly. Much of the anticipated surge of nuclear construction is by existing utilities that already operate conventional nuclear plants. It makes economic sense for many of them to continue in this direction. That argument does not hold in New Mexico, and we should embrace the construction of one or more passive nuclear power reactors as this technology matures.

We would expand our use of local coal reserves with the new Desert Rock power plant, and enjoy very low air emissions from that plant, except for the increased carbon footprint. Longer term (10 – 20 years), as power needs increase, we should consider a passive reactor nuclear plant instead of another coal fired plant. Some existing local coal fired units may approach the end of their design life and be retired. That retired power could be replaced by nuclear generation, with zero air emissions and carbon footprint.

A nuclear building program in the Four Corners would greatly enhance the growth of a local and regional high technology professional and vocational workforce. San Juan College would step up with new programs to educate the vocational workforce needed to build and operate a nuclear plant. The college should also benefit from creative financing support similar to that proposed for Desert Rock. The Four Corners and New Mexico would be recognized as an energy focal point in the U.S., with an exceptional balance of conventional, renewable, and nuclear energy generation, along with our strong base in oil/gas production.

Benefits: Zero air emissions impact; No carbon footprint; Cost effective electricity generation; Foster high technology educational and employment basis in the Four Corners; Proximity to current New Mexico and future Nevada spent fuel storage site.

Tradeoffs: Minority negative public opinion related to plant safety and spent fuel containment.

Differing Opinion: While it may be true that nuclear power plants have almost no carbon dioxide emissions (except in construction and in mining, processing and supplying the uranium fuel) and low global warming impact, there are other enormous liabilities which make them, in my opinion, the least desirable alternative to replace fossil fuel-fired power plants.

The availability of fissionable uranium (U-235) is not discussed. The supply will be quite limited, especially if the rate of usage increases significantly. One proposed solution, going to breeder reactor technology, would involve transport of radioactive materials to and from reprocessing plants, entailing enormous problems of safety and security.

The stated maintenance cost of 1.7 cents per Kwh for nuclear plants is deceptive. In all likelihood it does not include the cost of decommissioning the facility at the end of its useful life, nor the totally unknown cost of eventual "permanent" storage of the radioactive waste products. It also does not include any portion of the massive and continuing federal subsidies for nuclear R&D ($145 billion between 1947 and 1998 according to one source).

The issue of permanent storage of radioactive wastes (spent fuel) is not adequately discussed. The federal government and the nuclear industry have had half a century to develop permanent storage facilities; it seems they are no closer to a solution than when they started. Yucca Mountain is not close to viable, the latest blow being a federal court decision upholding the Nevada State Water Engineer's authority to deny the federal government's use of groundwater at the site. Even if a permanent storage facility is eventually developed, there is a major moral issue. I do not believe we have the right to impose an almost perpetual guardianship role on future generations (8,000 generations if the estimate of a 200,000 year storage time for plutonium wastes is accurate).

<u>II. Description of how to implement</u>
A. Mandatory or voluntary
B. Indicate the most appropriate agency(ies) to implement

<u>III. Feasibility of the option</u>
A. Technical –
B. Environmental –
We would expand our use of local coal reserves with the new Desert Rock power plant, and enjoy very low air emissions from that plant, except for the increased carbon footprint. Longer term (10 – 20 years), as power needs increase, we should consider a passive reactor nuclear plant instead of another coal fired plant. Some existing local coal fired units may approach the end of their design life and be retired. That retired power could be replaced by nuclear generation, with zero air emissions and carbon footprint.
C. Economic –
Nuclear plants have lower maintenance costs (about 1.7 cents per kwh, v.s. 3 - 5 cents for a fossil fuel units). Operating experience has advanced greatly over the 30 years since Three Mile Island, with plants running at 90% capacity -- up from 70% in the 1970s.

<u>IV. Background data and assumptions used:</u>
Reference: Energybiz magazine Vol. 4, Issue 3 (May 07, June 07) "Agency Gets Ready for Nuclear Renaissance" -- "Repackaging the Nuclear Option" -- "GE Gears Up." Vol. 4, Issue 4 (July 07, August 07) “Bechtel sees Nuclear Surge” and “The Nuclear Balance Sheet.”

<u>V. Any uncertainty associated with the option</u>: TBD
<u>VI. Level of agreement within the work group for this mitigation option</u>: To Be Determined.
<u>VII. Cross-over issues to the other Task Force work groups:</u>
Cross over with the Energy Efficiency, Renewable Energy, and Conservation Section

OVERARCHING: POLICY

Mitigation Option: Reorganization of EPA Regions

I. Description of the mitigation option

The Four Corners geographic area is under the jurisdiction of three different regions of the Environmental Protection Agency: Colorado and Utah are in Region 8, headquartered in Denver; New Mexico is in Region 6, headquartered in Dallas; and Arizona (and the Navajo Nation, which is in both Arizona and New Mexico) is in Region 9, headquartered in San Francisco.

Due to the abundance of coal and oil and gas in the San Juan Basin energy development in the area is likely to continue. It is becoming increasingly well-documented that the majority of the pollution experienced in the Four Corners area is coming from coal-fired power plants on or near reservation lands in New Mexico as well as oil and gas development throughout the region. The EPA staff engaged in addressing environmental impacts from oil and gas development, and responsible for actually permitting or overseeing permitting of stationary sources (power plants) needs to be located where the pollution is happening and be responsible to the recipients of that pollution as well as to hold its generators accountable.

A permanent EPA human presence within the area of energy development and pollution would sensitize EPA personnel to the issues within the Four Corners area. Creating an interregional office of the EPA with jurisdictional authority in order to include within a single jurisdiction the pollution generating sources and the public lands and communities they impact would improve EPA effectiveness in oversight and permit processing by facilitating communication and focusing feedback.

II. Description of how to implement

Create a permanent inter-region office within the EPA chartered to focus on, and located in, the Four Corners region. The office would assume all regional duties with respect to the Four Corners area, and have responsibility for overseeing state and tribal permitting, permitting stationary sources in the absence of state or tribal permitting, and any activities relating to oil and gas development currently performed by the various regions.

III. Feasibility of the Option

EPA Headquarters, as well as the three regions involved, would need to approve this option. The states and tribes would need to support this option as well.

IV. Background data and assumptions

The statement by Colleen McKaughan of Region 9 to the Durango Herald epitomizes our perception of the sensitivity of Region 9 personnel to the issues in the Four Corners region. As quoted in the Durango Herald on September 15, 2006, Ms. McKaughan, an air-quality expert with the federal Environmental Protection Agency's Region 9, said the Four Corners region has air so clean that it can absorb additional pollutants without harm. She said the EPA had no significant concerns about the proposed coal-fired Desert Rock plant.

V. Any uncertainty associated with the option There is a high level of uncertainty in getting something like this passed politically and how long it would take is an unknown.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues Oil and Gas Work Group, Other Sources Work Group.

OVERARCHING: MERCURY

Mitigation Option: Clean Air Mercury Rule Implementations in Four Corners Area

I. <u>Description of the mitigation option</u>
States and tribes are presently drafting regulations (some such as NM and CO now have completed rules, see appendix on NM & CO) to meet the Clean Air Mercury Rule (CAMR) while simultaneously meeting their mission to protect public health and the environment. For states, this means allocating mercury allowances to electric generating facilities to operate. CAMR may eventually have profound effects on the amount of mercury reduced from the affected facilities.

States participating in the Task Force might work in concert to determine if even greater reductions are possible than initially scheduled in CAMR. Some examples of working in concert might include:

- "Incentivizing" early mercury reductions at CAMR-affected facilities;
- Retiring any excess allowances that may exist (Colorado has in effect a "Colorado Citizens' Trust" to effectively permanently set aside excess allowances);
- Addressing the concerns for local mercury impacts ("hot spots") from new and proposed facilities in the Four Corners area by requesting that State air quality permitting agencies consider this hot spot criterion in their decision to approve/disapprove facilities' air quality permit requests (as individual state budgets and their "set aside allowances" may be inappropriate indicators of the impacts the local area might receive from power plants in Four Corners);
- Promoting additional mercury studies (e.g., air deposition) that would benefit Four Corners area (could/should be tied to option #5);
- Requiring early installation of mercury CEMs at facilities (to better gauge effectiveness of various co-control efforts);
  - For example, Mercury CEMs will be installed on 2 of the 4 units at San Juan by 12/31/07 and the other 2 units by 12/31/08.
- Developing more stringent control requirements for facilities in Four Corners Area;
- Other examples as identified.

II. <u>Description of how to implement</u>
<u>A. Mandatory or voluntary:</u>
Could be either mandatory or voluntary depending on the specifics of the option.

Differing Opinion: Since many of Four Corners Area lakes, streams, and rivers are currently under a mercury advisory, mandatory control of mercury is necessary. The health of humans and other living beings is at risk

<u>B. Indicate the most appropriate agency(ies) to implement:</u>
States' environmental (permitting) agencies

<u>III. Feasibility of the option</u>
<u>A. Technical:</u> Some of the technical options may be difficult to implement, especially depending on the timing. That is, CAMR plans are due to EPA by November 2006 and hence options developed here may come too late. However, options developed here could be possibly used in the states' future allocation schemes and/ or approaches surrounding CAMR.
<u>B. Environmental:</u> N/A
<u>C. Economic:</u> Difficult to ascertain as this depends on the specifics of the option developed.

IV. Background data and assumptions used

CAMR information and data are plentiful; however, the long-term application and effectiveness of various strategies to reduce mercury from power plants is difficult to predict.

Basic Information on New Mexico CAMR:

- Rule applicability covers coal-fired EGUs (presently 4 units at San Juan Generating Station and 1 unit at Escalante Generating Station).
- Mandatory mercury monitoring by sources begins 1/1/09.
- Mercury limitations become effective 1/1/10.
- See Tables 1 and 2, below, for mercury emissions data and proposed limitations.
- Monitoring includes installing monitoring systems (CEMS or sorbent traps), certification, performance test, and recording, quality-assuring, and reporting data.
- Initial monitoring performance test is 12 months (calendar year 2009).
- State rules takes state "budget" and turns it into state "cap" with portions of the cap assigned to facilities as facility-wide emission limitations as well as EPA-recommended new source set-aside.
- State rules prohibit participation in trading and banking program.
- State rules establish emissions fees to support one full-time equivalent for implementation of the mercury rules.

Table 1: New Mexico Mercury Emissions Data	
New Mexico Mercury Emissions (1999 EPA data; Tons)	1.09
New Mexico Mercury Emissions (2004 TRI data; SJGS + Escalante; Tons)	0.389
New Mexico Mercury Budget (2010-2017; Tons per year)	0.299
New Mexico Mercury Budget (2018 and after; Tons per year)	0.118

Table 2: New Mexico Mercury Limitations (Per year)						
	2010-2017			**2018 and after**		
	Tons	Ounces	%	Tons	Ounces	%
Total "State Cap"	0.299	9,568	100 %	0.118	3,776	100 %
San Juan Generating Station	0.244	7,808	81.6 %	0.104	3,323	88 %
Escalante Generating Station	0.04	1,280	13.4 %	0.01	340	9 %
New Source Set-Aside	0.015	480	5 %	0.035	113	3 %

Basic Information on Colorado CAMR:

Overview: Colorado's Air Quality Control Commission adopted a rule specific to CO's Utility Hg Reduction Program on 2/6/07. This rule specifies 100% of the state's allowances be transferred into the State's General Account. The State allocates allowances to units based on annual actual emissions, up to Model Rule allocations with an option to access additional allowances based on need through a safety-valve. In addition, the rule requires phased reductions over time on a rolling 12-month average basis, exempting low mass emitters and new units with existing permits in place:

• 2012: Pawnee and Rawhide 0.0174 lb/GWh or 80% inlet Hg capture;
• 2014: 0.0174 lb/GWh or 80% inlet Hg capture; and
• 2018: 0.0087 lb/GWh or 90% inlet Hg capture.

This rule allows for averaging of units at the same plant. The rule also provides soft-landing, requiring Best Available Mercury Control Technology installation if units demonstrate to the State that they cannot meet the performance standard. Finally, the rule includes a provision associated with retirement of allowance accrual, beginning in 2016, 2019 and every five years thereafter, if no separate rulemaking is commenced prior.

Trading: Yes, but allocations are made based on actual emissions.

Allowance Allocations: Up to 95% in phase I and 97% in phase II, with the remainder used for new units. However, actual allocations are made based on actual emissions, which are reduced over time due to state-only Hg emission standards. Therefore allocation amounts are also expected to decrease over time.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium – again, the long term application and effectiveness of various strategies to reduce mercury from power plants is difficult to predict.

VI. Level of agreement within the work group for this mitigation option

TBD.

VII. Cross-over issues to the other Task Force work groups

TBD.

Mitigation Option: Federal Clean Air Mercury Rule (CAMR) Implementation on the Navajo Nation

I. Description of the mitigation option

The Environmental Protection Agency (EPA) promulgated the Clean Air Mercury Rule (CAMR) on May 18, 2005. CAMR established a mechanism by which mercury (Hg) emissions from new and existing coal-fired power plants (EGUs) are capped at nation-wide levels of 38 tons/year effective in 2010 and 15 tons/year effective in 2018. EPA then established Hg emission levels for each state and for Indian country in cases where there are existing EGUs; this includes the Navajo Nation. State and Tribal plans to implement and enforce Hg emission levels were to be submitted to EPA by November 17, 2006. State plans can be more stringent than the EPA Model Rule and may or may not allow trading or banking of emissions allowances.

In cases where a State or Indian Tribe does not have an approvable plan in place by the prescribed deadline of March 17, 2007, EPA may implement a Federal plan by May 17, 2007. In order to facilitate this action, EPA published proposed rules on December 22, 2006. These rules are expected to be finalized by May 17, 2007, and will be used to implement CAMR on the Navajo Nation. A major shortcoming of these EPA rules is the lack of provision for meaningful public participation in the process to develop and allocate specific Hg emission limits for existing and proposed EGUs on Navajo Nation lands. This is significant since the Navajo Nation mercury emissions budget is larger than that of either Arizona, New Mexico, or Utah, and almost as large as the budget for Colorado.

The Navajo EPA, Region 9 EPA, and the operating agencies for the Four Corners Power Plant and the Navajo Generating Station – Arizona Public Service Company (APS) and the Salt River Project Agricultural Improvement and Power District (SRP), respectively – have already had discussions regarding a potential allocation methodology for the Navajo Nation. A meeting was held on July 10, 2006, at which Region 9 EPA presented a "strawman" proposal which differed significantly from the EPA model Rule with respect to the amount and disposition of the new source set-aside portion. This proposal has not been well-received by APS and SRP. The degree to which the air quality agencies in the surrounding, contiguous, and sometimes overlapping States of Arizona, Colorado, New Mexico and Utah have been aware of these early meetings is not known. From all appearances it seems that much greater effort should go towards facilitating adequate public participation in this process. The prime responsibility for achieving this rests with Region 9 EPA.

At a minimum the process for allocation of mercury emissions limits to EGUs in Navajo lands should be at least as open to public participation as the most transparent State CAMR process has been. For the Navajo Nation this might include informational meetings and public hearings in Window Rock and Page, Arizona, and Farmington, New Mexico. Final decisions on nature and location of meetings should be negotiated among the various jurisdictional agencies.

II. Description of how to implement

A. Mandatory or voluntary

This should be mandatory. In the past, public participation has been a cornerstone of EPA policy and in fact is mandated in many of their regulations.

B. Indicate the most appropriate agencies to implement

Region 9 EPA, with assistance and cooperation of Navajo EPA and air quality agencies in affected States.

III. Feasibility of the option

A. Technical: Entirely feasible

B. Environmental: Feasible

Economic: Feasible; minor administrative costs to conduct public meetings and hearings
Political: Medium feasibility. Some advocacy to Region 9 EPA may be needed to implement this option.

IV. Background data and assumptions used
A small amount of information has been received from Region 9 EPA.
Clean Air Mercury Rule making process is in process so newer information may now be available

V. Any uncertainty associated with the option
Medium – responsibility to implement rests primarily with Region 9 EPA.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other Task Force work groups TBD

OVERARCHING: AIR DEPOSITION STUDIES

Mitigation Option: Participate in and Support Mercury Studies

I. Description of the mitigation option

Background

Rationale and Benefits: Methyl mercury is a known neurotoxin affecting humans and wildlife. Coal-fired power plants are the number one source of mercury emissions in the United States[1]. The Four Corners already is home to several power plants that are large emitters of mercury and additional coal-powered plants are proposed for the region. Individuals and community groups in the San Juan Mountains have expressed great concern about mercury emissions in our region and the existing mercury fish consumption advisories in several reservoirs. Studies of mercury in air deposition, the environment and in sensitive human populations (such as pregnant women) are necessary to set a baseline for current levels and to detect future impacts of increased mercury emissions on these sensitive human populations and natural resources, including the Weminuche Wilderness, a Federal Class I Area.

Existing mercury data for the Four Corners region: Total mercury in wet deposition has been monitored at Mesa Verde National Park since 2002 as part of the Mercury Deposition Network (MDN)[2]. Results show mercury concentrations among the highest in the nation. Mercury concentrations have been measured in snowpack at a few sites in the San Juan Mountains by the USGS[3] and moderate concentrations similar to the Colorado Front Range have been recorded. Mercury concentrations in sport fish from several reservoirs have exceeded the 0.5 microg/g action level resulting in mercury fish consumption advisories for McPhee, Narraguinnep, Navajo, Sanchez and Vallecito Reservoirs[4]. Sediment core analysis for Narraguinnep Reservoir show that mercury fluxes increased by approximately a factor of two after about 1970[5]. Finally, atmospheric deposition just to the surface of McPhee and Narraguinnep Reservoirs (i.e., not including air deposition to the rest of the watershed) is estimated to contribute 8.2% and 47.1% of total mercury load to these waterbodies, respectively[6].

Data Gaps: Very little data exists for the Four Corners Region with which to assess current risks and trends over time for mercury in air deposition, ecosystems, and sensitive human populations. Mercury amounts and concentrations in wet deposition at Mesa Verde National Park are not likely to portray the situation in the mountains where mercury may be deposited at higher concentrations and total amounts because of greater rates of precipitation and the process of cold condensation, which causes volatile compounds to migrate towards colder areas at high elevation and latitude[7]. No information about total mercury deposition from the atmosphere (i.e., including dry deposition) exists for low or high elevations in the Four Corners Region. Furthermore, analysis of sources of air deposition of mercury is lacking. Except for a handful of reservoirs, no information exists for incorporation of mercury into aquatic ecosystems and subsequent effects on food-webs. No systematic effort exists to document mercury impacts in a wide range of waterbodies over space and time. Lastly, impacts of mercury exposure to human populations are unknown.

Three new studies have begun or will begin in 2007, however. In 2007, the Mountain Studies Institute (MSI) will measure total mercury in bulk atmospheric deposition (collector near NADP station at Molas Pass), in lake zooplankton (invertebrates eaten by fish), and in lake sediment cores in the San Juan Mountains, a project funded by the U.S. EPA and USFS[8]. Dr. Richard Grossman is measuring mercury levels in hair collected from pregnant women in the Durango vicinity. Lastly, the Pine River Watershed Group (via the San Juan RC&D) recently was granted start-up funds to initiate event-based sampling of mercury in atmospheric deposition at Vallecito Reservoir and accompanying back-trajectory analyses to locate the source of these storm events.

Option 1: Install and operate a long-term monitoring station for mercury in wet deposition for a location at high elevation where precipitation amounts are greater than the site at Mesa Verde NP. Co-location of the collector with the NADP site at Molas Pass would provide data pertinent to Weminuche Wilderness and the headwaters of Vallecito Reservoir. This monitor would be part of the Mercury Deposition Network (MDN). Upgrading the NADP monitoring equipment at Molas Pass to include the MDN specifications would cost $5,000 to $6,000, while annual monitoring costs are $12,112 plus personnel as of September 2006.

Option 2: Install and operate a long-term monitoring station for mercury in total deposition (wet and dry) for at least one MDN station in the Four Corners Region. Speciated data will be collected and analyzed as is feasible. The MDN is currently developing this program and costs are anticipated at about $50,000 per year.

Option 3: Support multi-year comprehensive mercury source apportionment study to investigate the impact of local and regional coal combustion sources on atmospheric mercury deposition. This type of study would require additional deposition monitoring (i.e., recommendations 1 & 2 above). Speciated data will be collected and analyzed as is feasible. A mercury monitoring and source apportionment study was recently completed for eastern Ohio. (http://pubs.acs.org/cgibin/asap.cgi/esthag/asap/html/es060377q.html[9]). This study would build on the pilot study planned for Vallecito Reservoir. Costs TBD.

Option 4: Support a study of mercury incorporation and cycling in aquatic ecosystem food-webs, including total and methyl mercury in the food-webs of lakes and wetlands. This option includes studies that determine which ecosystems currently have high levels of total and methyl mercury in food-web components, how mercury levels in ecosystems change over time, where the mercury is coming from, and what conditions are causing the mercury to become methylated (the toxic form of mercury that bio-accumulates in food-webs). This information would allow tracking of mercury risks over time and space and serves as the basis for predicting future impacts. Existing reservoir studies and the upcoming MSI investigation serve as a starting point to build a collaborative and systematic approach. Costs TBD.

Option 5: Support continued studies of mercury concentrations in sensitive human populations in the region to understand what exposure factors increase likelihood of unhealthy mercury levels in the body. Dr. Richard Grossman's study serves as a starting point to continue this effort. Costs TBD.

Option 6: Form a multi-partner Mercury Advisory Committee that would work collaboratively to prioritize research and monitoring needs, develop funding mechanisms to sustain long-term mercury studies, and work to communicate study findings to decision-makers. The Committee would include technical experts and stakeholder representatives from States, local governments, land management agencies, watershed groups, the energy industry, etc.

II. Description of how to implement

See above. Studies would utilize the existing Mercury Deposition Network and expertise developed from past and ongoing studies. Investigators could include scientists from academia, non-profit, private and government organizations and agencies.

III. Feasibility of the Option

Technical -Very feasible; all technology exists or is in development for the above options.

Environmental – Very feasible. Harmful effects on the environment are negligible and permits for sample collection should be easy to obtain.

Financial – Uncertain. It is likely that a consortium of funding entities collaborate for these options. Potential partners include States, industry, US-EPA, USDA-Forest Service, US-Department of Energy, and local governments, watershed groups and public health organizations.

IV. Background data and assumptions used See introduction section

V. Any uncertainty associated with the option Funding uncertainty.

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other source groups Energy and Monitoring Groups

Citations:

[1] See http://www.epa.gov/mercury/about.htm.
[2] National Atmospheric Deposition Program (NADP). Mercury Deposition Network http://nadp.sws.uiuc.edu/mdn/. National Trends Network. http://nadp.sws.uiuc.edu/.
[3] Campbell, D, G Ingersoll, A Mast and 7 Others. Atmospheric deposition and fate of mercury in high-altitude watersheds in western North America. Presentation at the Western Mercury Workshop. Denver, CO. April 21, 2003.
[4] Colorado Department of Public Health and Environment website: http://www.cdphe.state.co.us/wq/FishCon/FishCon.htm and http://www.cdphe.state.co.us/wq/monitoring/monitoring.html.
[5] Gray, JE, DL Fey, CW Holmes, BK Lasorsa. 2005. Historical deposition and fluxes of mercury in Narraquinnep Reservoir, southwestern Colorado, USA. Applied Geochemistry 20: 207-220.
[6] Colorado Department of Public Health (CDPHE). 2003. Total Maximum Daily Load for Mercury in McPhee and Narraguinnep Reservoirs, Colorado: Phase I. Water Quality Control Division. Denver, CO. http://www.epa.gov/waters/tmdldocs/Mcphee-NarraguinnepTMDLfinaldec.pdf.
[7] Schindler, D. 1999. From acid rain to toxic snow. Ambio 28: 350-355
[8] See http://www.mountainstudies.org/Research/airQuality.htm.
[9] See http://pubs.acs.org/cgi-bin/asap.cgi/esthag/asap/html/es060377q.html

OVERARCHING: GREENHOUSE GAS MITIGATION

Mitigation Option: CO_2 Capture and Storage Plan Development by Four Corners Area Power Plants

I. Description of the mitigation option
Carbon sequestration refers to the provision of long-term storage of carbon in the terrestrial biosphere, underground, or the oceans so that the buildup of carbon dioxide (the principal greenhouse gas) concentration in the atmosphere will reduce or slow. In some cases, this is accomplished by maintaining or enhancing natural processes; in other cases, novel techniques are developed to dispose of carbon.

Emissions of CO_2 from human activity have increased from an insignificant level two centuries ago to over twenty five billion tons worldwide today (1). The additional CO_2, a major contributor to Greenhouse gases, contribute to the phenomenon of global warming and could cause unwelcome shifts in regional climates (1).

The contribution of CO_2 from the 2 major power plants in the 4Corners area is approximately 29,000,000 Tons of CO_2 per year. The proposed Desert Rock Energy Project would add an approximate additional 11,000,000 Tons of CO_2 per year.

Facilities in the Four Corners area should begin developing carbon sequestration plans to mitigate this important global issue. Four Corners area power plants should research & develop way to reduce their CO_2 emissions.

Benefits: CO_2 emissions reductions would reduce the Greenhouse Gases output of the 4Corners area. Carbon sequestration would slow the buildup of CO_2 emissions in the atmosphere. It would be a regional action to reducing the trends of global warming. Benefits would be environmental and economic. CO_2 capture and injection may have a beneficial use for enhanced oil recovery in the 4C area

Tradeoffs: no tradeoffs

Burdens:
The benefits of protecting the climate will be realized globally and far in the future; the cost of each GHG emissions reduction project is local and immediate.

Cost to power plants, administrative costs.

Sequestration, isolating the CO_2 emissions is cheap; however, capturing/storing is expensive.

II. Description of how to implement
A. Mandatory or voluntary
Combination of mandatory and voluntary
Voluntary: 4C area power plants should begin developing Carbon Sequestration Plans
Mandatory limits or allocations may be set by State and Federal regulators in the near future.

B. Indicate the most appropriate agency(ies) to implement
State and Federal Regulators can allocate Carbon budgets which will lead to more controls
Appropriate State/Federal agencies to help assess Carbon potential storage areas as part of planning process

III. Feasibility of the option

A. Technical: Technologies exist; many are in R&D phase.
B. Environmental: Capturing and storing CO_2 emissions is difficult.
C. Economic: Capturing CO_2 emissions is expensive.
D. Legal: Liability of CO_2 storage process

IV. Background data and assumptions used

1. Carbon Sequestration Technology Roadmap and Program Plan 2006, US DOE
2. CO2 emissions from Four Corners area power plants (4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV10)
3. San Juan Generating Station has a total 1798 MW generation capacity, and emits approximately 13,097,000 Tons CO_2/yr. Approx 7,300 Tons CO_2 per MW generation capacity. San Juan Generating Station CO_2 rationing by MW is used as an estimation for CO_2 emissions from Desert Rock Energy Facility. Based on this assumption, the CO_2 emissions from Desert Rock Energy Facility will be approximately 11,000,000 Tons/yr.
4. US DOE Carbon Sequestration Regional Partnerships:
http://www.fossil.energy.gov/programs/sequestration/index.html
New Mexico Partnerships
http://www.fossil.energy.gov/programs/projectdatabase/stateprofiles/2004/New_Mexico.html

V. Any uncertainty associated with the option

Medium.

VI. Level of agreement within the work group for this mitigation option.

To Be Determined.

VII. Cross-over issues to the other Task Force work groups

CO_2 emissions reduction Cross-over issue with other energy industries such as Oil & Gas. Oil & Gas industries could also be held responsible for developing Carbon sequestration plans.

CO_2 capture and injection may have a beneficial use for enhanced oil recovery in the Four Corners area.

Mitigation Option: Climate Change Advisory Group (CCAG) Energy Supply Technical Work Group Policy Option Implementation in Four Corners Area

I. Description of the mitigation option

The New Mexico Climate Change Advisory Group (CCAG) is a diverse group of stakeholders from across New Mexico. At the end of 2006, the group will put forth policy options for reducing greenhouse gas emissions in NM to 2000 levels by the year 2012, 10% below 2000 levels by 2020 and 75% below 2000 levels by 2050. 69 recommendations covering transportation, land use, energy supply, agriculture and forestry were made which if implemented would exceed emissions reduction target for 2020.

A GHG emissions inventory for New Mexico prepared by The Center for Climate Strategies (2) showed electricity generation to comprise 40% of the states GHG emissions. The electricity generation sector is a source contributor of GHG and there are many areas for potential reductions. In the future, if the proposed Desert Rock Energy Project comes online, the additional 11 million tons of CO2 from Desert Rock would increase the electricity generation portion of New Mexico GHG emissions to approximately 50%.

The energy supply technical work group drafted options for renewable portfolio standards and advanced coal technologies (1). These policy options should be applied to Four Corners area facilities. The contribution of CO_2 from the 2 major power plants in the 4Corners area is approximately 29,000,000 Tons of CO_2 per year. The proposed Desert Rock Energy Project would add an additional estimated 11,000,000 Tons of CO_2 per year (3).

Local State/Federal Regulating agencies should work with the existing and proposed power plants to collaborate to help realize the targets of the Climate Change Advisory Group. CO_2 sequestration technologies and other Greenhouse gas mitigation strategies should be assessed and implemented to meet the targets.

Benefits:
Environmental: reduction of greenhouse gas emissions to 2000 levels by the year 2012, 10% below 2000 levels by 2020 and 75% below 2000 levels by 2050. Mitigation of adverse climate change effects

Net economic savings for the state's economy

Tradeoffs: none
Burdens: Cost to existing and proposed power pants and administrators

II. Description of how to implement

A. Mandatory or voluntary
Combination of mandatory and voluntary

B. Indicate the most appropriate agency(ies) to implement
State and Federal Regulators:
Oil Conservation Division (NMOCD)
New Mexico Air Quality Bureau
New Mexico Energy, Minerals, and Natural Resources Division

Other Four Corner State Environmental Protection Agencies

III. Feasibility of the option

A. Technical: TBD

B. Environmental: TBD
C. Economic: TBD

IV. Background data and assumptions used

(1) New Mexico Climate Change Advisory Group (CCAG): http://www.nmclimatechange.us/
(2) Draft New Mexico Greenhouse Gas Inventory and Reference Case Projections, The Center for Climate Strategies, July 2005
(3) CO_2 emissions from Four Corners area power plants (4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV9)
(4) San Juan Generating Station has a total 1798 MW generation capacity, and emits approximately 13,097,000 Tons CO_2/yr. Approx 7,300 Tons CO_2 per MW generation capacity. San Juan Generating Station CO_2 rationing by MW is used as an estimation for CO_2 emissions from Desert Rock Energy Facility. Based on this assumption, the CO_2 emissions from Desert Rock Energy Facility will be approximately 11,000,000 Tons/yr.
(5) Carbon Sequestration Technology Roadmap and Program Plan 2006, US DOE

V. Any uncertainty associated with the option Medium.

VI. Level of agreement within the work group for this mitigation option

To Be Determined.

VII. Cross-over issues to the other Task Force work groups

Greenhouse Gas (GHG) emissions reduction Cross-over issue with other energy industries such as Oil & Gas.

OVERARCHING: CAP AND TRADE

Mitigation Option: Declining Cap and Trade Program for NO_x Emissions for Existing and Proposed Power Plants

I. Description of the mitigation option

Cap and trade is a policy approach to controlling large amounts of emissions from a group of sources at costs that are lower than if sources were regulated individually. The approach first sets an overall cap, or maximum amount of emissions per compliance period, that will achieve the desired environmental effects. Authorizations to emit in the form of emission allowances are then allocated to affected sources, and the total number of allowances cannot exceed the cap.

Individual control requirements are not specified for sources. The only requirements are that sources completely and accurately measure and report all emissions and then turn in the same number of allowances as emissions at the end of the compliance period.
For example, in the Acid Rain Program, sulfur dioxide (SO_2) emissions were 17.5 million tons in 1980 from electric utilities in the U.S. Beginning in 1995, annual caps were set that decline to a level of 8.95 million allowances by the year 2010 (one allowance permits a source to emit one ton of SO_2). At the end of each year, EPA reduces the allowances held by each source by the amount of that source's emissions (1, EPA Clean Air Markets).

A declining cap and trade program means that the cap would be slightly lowered over time to reduce the total NOx emissions in the Four Corners area. A declining cap and trade program would be effective for the Four Corner areas' electric generating units.
The power plants in the area have continuous emissions monitors. We can measure accurately each plant's NOx emissions. In 2005 the NO_x emissions from San Juan Generating Station were 27,000 tons. The Four Corners Power Plant emitted 42,000 tons (2). Desert Rock Energy facility would add an approximate 3,500 tons/yr (2). NO_x emissions from electricity generating units (EGUs) will continue to be reported and recorded under the EPA Acid Rain Program (3). So the data is available. For each of these facilities the costs for additional controls and NO_x emissions reductions is different.

Electric Generating Units (EGUs) will be defined as it is EPA's Clean Air Interstate Rule:
(a) Except as provided in paragraph (b) of this definition, a stationary, fossil-fuel-fired boiler or stationary, fossil fuel fired combustion turbine serving at any time, since the start-up of a unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.
(b) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (a) of this definition starting on the day on which the unit first no longer qualifies as a cogeneration unit.

The program will cover all EGUs.

The Four Corners area declining cap and trade program would cap NO_x levels from EGUs at current levels. The cap could be lowered 5% every 10 years or a collaboratively agreed on level.

The Declining cap and trade program would include all EGUs in the Four Corners area, and could also possible be extended to oil & gas sources. New sources could obtain offsets.

There should be some discussion regarding how the cap would be set; as well as how to protect against hot spots.

Benefits: The cap will prevent NO_x emissions from the Four Corners area sources from increasing. Regardless of new power plants, sources will have to find a way to keep overall NO_x emissions below the declining cap.

The program will reduce NO_x emissions in the Four Corners area.
Power Plants would continue to look at new ways to reduce emissions.

Differing Opinion: Cap and trade is a band aid approach to reduction of emissions. It may look good on paper, but does nothing to enhance the air quality. Cap and trade should not be an option for power plant or oil and gas emissions in the Four Corners Area. Extensive improvement of the air quality and consideration for the health and welfare of the people and the environment should be the top priority.

Tradeoffs: None

Differing Opinion: The trade off of cap and trade is that the numbers look good, but in reality, the emissions are still in existence.

Burdens:
Regulatory agency needs to be able to collect, verify all emissions information and be able to enforce rule

II. Description of how to implement
A. Mandatory or voluntary
Mandatory

B. Indicate the most appropriate agency(ies) to implement
State Air Quality Agencies and Federal EPA

III. Feasibility of the option
A. Technical: NO_x emissions are measured using CEMS by large Power Plants. Complete and verified emissions measurements are reported by the Four Corners area power plants and is available on the EPA Clean Air Markets: Data and Maps National Database: http://cfpub.epa.gov/gdm/

B. Environmental: NO_x control technologies are available.
C. Economic: The design and operation of the program are relatively simple which helps keep compliance and administrative costs low. Cost savings are significant because regulators do not impose specific reductions on each source. Instead, individual sources choose whether and how to reduce emissions or purchase allowances. Regulators do not need to review or need to approve sources' decisions, allowing them to tailor and adjust their compliance strategies to their particular economics (1). Power Plants may need retrofits or to buy or sell credits.

* Cumulative Effects Work Group: How would a 5% declining cap and trade program for NO_x in the Four Corners area affect visibility and ozone levels?

IV. Background data and assumptions used

1. EPA Clean Air Markets – Air Allowances
http://www.epa.gov/AIRMARKET/trading/basics/index.html

A cap and trade program also is being used to control SO_2 and nitrogen oxides (NO_x) in the Los Angeles, California area. The Regional Clean Air Incentives Market (RECLAIM) program began in 1994. [1]

2. NO_2 emissions from Four Corners area power plants
(4CAQTF_PowerPlant_WorkGroup_FacilityDataTableV9)
*NO_x emissions from existing power plants obtained from EPA Acid Rain database
*NO_x emissions from proposed Desert Rock Energy Facility from AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01)

3. EPA Clean Air Markets: Data and Maps National Database: http://cfpub.epa.gov/gdm/

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option To Be Determined.

VII. Cross-over issues to the other Task Force work groups
Declining Cap and Trade program would cross-over with Oil & Gas work group.

Mitigation Option: Four Corners States to join the Clean Air Interstate Rule (CAIR) Program

I. Description of the mitigation option

EPA finalized the Clean Air Interstate Rule (CAIR) on March 10, 2005. It is expected that this rule will result in the deepest cuts in sulfur dioxide (SO_2) and nitrogen oxides (NOx) in more that a decade (1).

The Clean Air Interstate Rule establishes a cap-and-trade system for SO_2 and NO_x based on EPA's proven Acid Rain Program. The Acid Rain Program has produced remarkable and demonstrable results, reducing SO_2 emissions faster and cheaper than anticipated, and resulting in wide-ranging environmental improvements. EPA already allocated emission "allowances" for SO2 to sources subject to the Acid Rain Program. These allowances will be used in the CAIR model SO2 trading program. For the model NOx trading programs, EPA will provide emission "allowances" for NOx to each state, according to the state budget. The states will allocate those allowances to sources (or other entities), which can trade them. As a result, sources are able to choose from many compliance alternatives, including: installing pollution control equipment; switching fuels; or buying excess allowances from other sources that have reduced their emissions. Because each source must hold sufficient allowances to cover its emissions each year, the limited number of allowances available ensures required reductions are achieved. The mandatory emission caps, stringent emissions monitoring and reporting requirements with significant automatic penalties for noncompliance, ensure that human health and environmental goals are achieved and sustained. The flexibility of allowance trading creates financial incentives for electricity generators to look for new and low-cost ways to reduce emissions and improve the effectiveness of pollution control equipment (1).

While most of the states are in the Eastern half of the US, Texas is participating in the CAIR program. Four Corners states could also participate and realize the emissions reduction benefits of CAIR.

SO_2 and NO_x contribute to the formation of fine particles and NO_x contributes to the formation of ground-level ozone. Fine particles and ozone are associated with thousands of premature deaths and illnesses each year. Additionally, these pollutants reduce visibility and damage sensitive ecosystems (1).

By the year 2015, the Clean Air Interstate Rule will result in (Eastern US benefits) (1):
-- \$85 to \$100 billion in annual health benefits, annually preventing 17,000 premature deaths, millions of lost work and school days, and tens of thousands of non-fatal heart attacks and hospital admissions.
-- nearly \$2 billion in annual visibility benefits in southeastern national parks, such as Great Smoky and Shenandoah.
-- significant regional reductions in sulfur and nitrogen deposition, reducing the number of acidic lakes and streams in the eastern U.S.

Based on an assessment of the emissions contributing to interstate transport of air pollution and available control measures, EPA has determined that achieving required reductions in the identified states by controlling emissions from power plants is highly cost effective (1).

States must achieve the required emission reductions using one of two compliance options: 1) meet the state's emission budget by requiring power plants to participate in an EPA-administered interstate cap and trade system that caps emissions in two stages, or 2) meet an individual state emissions budget through measures of the state's choosing (1).

CAIR provides a Federal framework requiring states to reduce emissions of SO_2 and NO_x. EPA anticipates that states will achieve this primarily by reducing emissions from the power generation sector.

These reductions will be substantial and cost-effective, so in many areas, the reductions are large enough to meet the air quality standards.

The Clean Air Act requires that states meet the new national, health-based air quality standards for ozone and PM2.5 standards by requiring reductions from many types of sources. Some areas may need to take additional local actions. CAIR reductions will lessen the need for additional local controls (1).

This final rule provides cleaner air while allowing for continued economic growth. By enabling states to address air pollutants from power plants in a cost effective fashion, this rule will protect public health and the environment without interfering with the steady flow of affordable energy for American consumers and businesses.

CAIR Timeline:
Promulgate CAIR Rule 2005, State implementation Plans Due 2006, Phase I Cap in Place for NOX, Phase I Cap in Place for SO2, Phase II Cap in Place for NOx and SO_2 (1). Caps will be fully met in 2015 to 2020, depending on banking.

The Four Corners area has existing and proposed power plants with significant NO_x and SO_2 emissions. The problem occurs over a relatively large area, there are a significant number of sources responsible for the problem, the cost of controls varies from source to source, and emissions can be consistently and accurately measured. Cap and Trade programs typically work better over broader areas. The Four Corners area as well as each state would realize a more successful Cap and Trade program from being a part of a large interstate program such as CAIR.

By joining the EPA CAIR program, the 4 Corner states of New Mexico, Colorado, Arizona, and Utah will also benefit from the interstate SO_2 and NOx emissions reductions.

Need some discussion on how to set cap, and protect against hot spots.

<u>Benefits:</u>
"If states choose to meet their emissions reductions requirements by controlling power plant emissions through an interstate cap and trade program, EPA's modeling shows that (for eastern states):

- In 2010, CAIR will reduce SO_2 emissions by 4.3 million tons -- 45% lower than 2003 levels, across states covered by the rule. By 2015, CAIR will reduce SO2 emissions by 5.4 million tons, or 57%, from 2003 levels in these states. At full implementation, CAIR will reduce power plant SO_2 emissions in affected states to just 2.5 million tons, 73% below 2003 emissions levels.
- CAIR also will achieve significant NOx reductions across states covered by the rule. In 2009, CAIR will reduce NOx emissions by 1.7 million tons or 53% from 2003 levels. In 2015, CAIR will reduce power plant NOx emissions by 2 million tons, achieving a regional emissions level of 1.3 million tons, a 61% reduction from 2003 levels. In 1990, national SO_2 emissions from power plants were 15.7 million tons compared to 3.5 million tons that will be achieved with CAIR. In 1990, national NO_x emissions from power plants were 6.7 million tons, compared to 2.2 million tons that will be achieved with CAIR (1)."

<u>Tradeoffs:</u> None
<u>Burdens:</u> Administrative costs on regulating agencies, including how to determine state or regional level cap; emissions control upgrade costs or purchasing allowances to power plants

<u>II. Description of how to implement</u>
A. <u>Mandatory or voluntary</u>

Mandatory emission caps, stringent emissions monitoring and reporting requirements with significant automatic penalties for noncompliance, ensure that human health and environmental goals are achieved and sustained (1).

B. Indicate the most appropriate agency(ies) to implement
State Air Quality Agencies and Federal EPA

III. Feasibility of the option

A. Technical: NOx emissions are measured using CEMS by large Power Plants. Complete and consistent emissions measurement and reporting by all sources guarantees that total emissions do not exceed the cap and that individual sources' emissions are no higher than their allowances

B. Environmental: NO_x, SO_2 control technologies are available.

C. Economic: The design and operation of the program are relatively simple which helps keep compliance and administrative costs low (2).

Cost savings are significant because EPA does not impose specific reductions on each source. Instead, individual sources choose whether and how to reduce emissions or purchase allowances. EPA does not review or need to approve sources' decisions, allowing them to tailor and adjust their compliance strategies to their particular economics (2).

The flexibility of allowance trading creates financial incentives for electricity generators to look for new and low-cost ways to reduce emissions and improve the effectiveness of pollution control equipment (1).

IV. Background data and assumptions used

1. EPA Clean Air Interstate Rule: http://www.epa.gov/cair/
2. EPA Clean Air Markets – Air Allowances
http://www.epa.gov/AIRMARKET/trading/basics/index.html
3. "EPA Enacts Long-Awaited Rule To Improve Air Quality, Health" Rick Weiss, Washington Post, Friday, March 11, 2005; Page A01 http://www.washingtonpost.com/wp-dyn/articles/A23554-2005Mar10.html
4. The White House – Council on Environmental Quality, Cleaner Air,
http://www.whitehouse.gov/ceq/clean-air.html

V. Any uncertainty associated with the option

Low – Program is based on a proven cap and trade approach
Need mechanism to be assured that a significant portion of actual reductions are achieved in the Four Corners area to assure the environmental benefit.

VI. Level of agreement within the work group for this mitigation option

To Be Determined

VII. Cross-over issues to the other Task Force work groups

Clean Air Interstate Rule would cross-over with Oil & Gas work group

OVERARCHING: ASTHMA STUDIES

Mitigation Option: Chronic Respiratory Disease Study for the Four Corners area to determine relationship between Air Pollutants from Power Plants and Respiratory Health Effects

I. Description of the mitigation option

This option would involve conducting a chronic respiratory disease study for the Four Corners area to determine the relationship between air pollutants from power plants and respiratory health effects. On going studies are necessary to continue to evaluate health risks associated with the large number of combustion emission sources in the area, primarily the two large coal-fired power plants in the area. Cumulatively, the two largest power plants in the area emit approx 66,000 tons/yr of nitrogen oxides (1). Nitrogen oxides are key precursor emissions to ozone.

Background

The NM Department of Health conducted a pilot project that linked daily maximum 8-hour ozone levels with the number of asthma-related emergency room visits at San Juan Regional Medical Center located in northwestern NM. The ozone and ER asthma data were collected for the period of 2000 - 2003. The number of emergency room visits in the summer increased 17% for every 10 ppb increase in ozone levels. This relationship occurred particularly following a two day lag and was statistically significant. These results are in general agreement with studies in other states and provide a foundation for tracking asthma-ozone relationships over time and space in NM (2).

The New Mexico Environment Department Air Quality Bureau operates and maintains three continuous ozone monitors in San Juan County. The eight-hour ozone design value in San Juan County has been maintained below the National Ambient Air Quality Standard for ozone of 0.08 ppm. The final eight-hour ozone design value for 2005 for San Juan County (San Juan Substation and Bloomfield monitors) was 0.072 ppm. The 2006 eight-hour ozone design value for San Juan County Substation monitor was 0.071 ppm. The 2006 eight-hour ozone design value for the San Juan County Bloomfield monitor was 0.069 ppm.

The Colorado Department of Public Health and Environment (CDPHE) has also researched asthma and links to environmental conditions. In a recent paper, “Holistic Approaches for Reducing Environmental Impacts on Asthma”, CDPHE, discusses staff researcher’s efforts to bring clarity to any identifiable linkage between environmental conditions and asthma. CDPHE investigated asthma rates throughout the state and compared these data against known and anecdotally reported information. Findings indicate that regions of Colorado do appear to have a higher incidence of asthma rates. In addition, some of the identified regions were not previously anticipated (e.g., rural communities), highlighting the need for further investigations (4).

The study describes asthma as a serious, chronic condition that affects over 15 million people in the United States. Asthma is a disease characterized by lung inflammation and hypersensitivity to certain environmental “triggers” such as pollen, dust, humidity, temperature and various environmental pollutants (dust, ozone, etc.), among others. Colorado has a particular problem with the occurrence of this condition, but the reasons for this are not well understood. Statewide there are an estimated 283,000 people with asthma, a figure that well exceeds national expectations. (4).

The CO-benefits risk assessment (COBRA) model is a recently developed screening tool that provides preliminary estimates of the impact of air pollution emission changes on ambient particulate matter (PM) air pollution concentrations, translates this into health effect impacts, and then monetizes these impacts

(5). A model such as this could be expanded to include other forms of air pollution such as ozone and be customized for the Four Corners Area.

Overarching modeling results should be cross-checked with local hospital inventory results and compared with other locations in the United States.

Benefits: Study would allow Four Corner area planning agencies to make better decisions and give the public a better idea of risk assessments

Tradeoffs: None

Burdens: Resources needed to conduct study

II. Description of how to implement

A. Mandatory or voluntary
Conduct coordinated outreach to obtain grant funding for the study.
(Study to be conducted by the end of 2009, with model development for assessing situation annually)

B. Indicate the most appropriate agency(ies) to implement
The states, the Environmental Protection Agency (EPA), and American Lung Association collaboration.

The need for these studies is obvious and the cost should be passed on to the utilities (and therefore the customers). However, even if these new studies find a significantly negative relationship between chronic respiratory disease and air pollutants, we already have proof that air pollutants increase the incidence of asthma. This mitigation option should include plans to utilize the study results for actively engaging policy-makers and changing regulations and enforcement, especially in geographic hot spots.

III. Feasibility of the option (indicate if assistance is needed from Cumulative Effects and/or Monitoring work groups)

Technical: The state and federal health organizations should be able to develop a 4C area model to assess the relationship between air pollutants from power plants and respiratory health effects

Environmental: Need for further modeling of Four Corners area customized to assessing respiratory health effect relationship to air pollutants from power plants. Existing COBRA model may be used as a starting point.

Economic: Grant funding would be required

*Monitoring work group: Assess whether or not we have the adequate data from monitoring stations to assess asthma situation. VOC and NOx emissions are contributors to ozone. Do we have good VOC data in the 4C area?

*Cumulative Effects work group: Assess the ozone trends in the 4C area. On average are ozone levels increasing or decreasing? Where are locations in the Four Corners area with the highest ozone concentrations? What are the relative contributions from power plants compared to oil and gas & other sources?

IV. Background data and assumptions used

(1) EPA Clean Air Markets – Data and Maps Query (2004 2005 2006 Facility & Unit Emissions Reports)
(2) New Mexico Department of Health Ozone Study
(3) New Mexico Environment Department – Ambient Ozone Level Data

(4) Holistic Approaches for Reducing Environmental Impacts on Asthma, Paper # 362, Prepared by Mark J. McMillan, Mark Egbert, and Arthur McFarlane, Colorado Department of Public Health and Environment.
(5) User's Manual for the CO-Benefits Risk Assessment (COBRA) Screening Model, US EPA, June 2006

V. Any uncertainty associated with the option Medium

VI. Level of agreement within the work group for this mitigation option To Be Determined

VII. Cross-over issues to the other Task Force work groups Oil and Gas and Other Sources Work Groups

OVERARCHING: CROSSOVER

Mitigation Option: Install Electric Compression

I. Description of the mitigation option

Overview

- Electric Compression would involve the replacement or retrofit of existing internal combustion engines or proposed new engines with electric motors. The electric motors would be designed to deliver equal horsepower to that of internal combustion engines. However, the limitation of doing so is predicated by the electrical grid that would exist in a given area to provide the necessary capacity to support electrical compression.

According to projections, at least 12,500 new gas wells will be drilled in the San Juan Basin over the next 20 years. It is said that this gas field is loosing pressure and compression on thousands of wells is necessary. Pollution emissions from production engines are rapidly increasing. To date, there is no cumulative emissions measurement.

Using BLM figures, an average gas powered wellhead compressor at 353,685 hp-hr per year at 13.15g per hp-hr = 4,650,957 g/year of NO_x. This is just an example of NO_x emissions. This figure does not account for other compounds in exhaust emissions such as VOCs, carbon monoxide, etc. This is equivalent to a 17 car motorcade running non-stop, circling your house 24 hours per day.

Gas powered wellhead compressors and pumpjacks are being installed in close proximity to inhabited homes and institutions. The City of Aztec required electric compressors, although that ordinance was not enforced, on wellhead engines within the city limits prior to 2004 when the ordinance was revised. Electric engines were required in order to protect citizens from noxious emissions from gas fired engines near homes. Electric engines are thought to be quieter than gas fired engines; therefore reducing noise pollution also.

Gas fired engines are being installed on wells in close proximity to existing electric lines. Electric engines should be required on all sites near power lines especially near homes. In areas where there is no electricity, best available technology must be implemented such as 2g/hp/hr engines, catalytic converters, etc.

Air Quality/Environmental

- Elimination of criteria pollutants that occur with the combustion of hydrocarbon fuels (natural gas, diesel, gasoline). Displacement of emissions to power generating sources (utilities).

Economics

- The costs to replace natural gas fired compressors with electric motors would be costly.
- The costs of getting electrical power to the sites would be costly. It could require a grid pattern upgrade which could costs millions of dollars for a given area.
- A routine connection to a grid with adequate capacity for a small electric motor can be $18K to $25K/site on the Colorado side of the San Juan Basin.
- A scaled down substation for electrification of a central compression site can range between $250K and $400K.
- Suppliers/Manufacturers would have to be poised to meet the demand of providing a large number of electrical motors, large and small.

Tradeoffs

- While the sites where the electrical motors would be placed would not be sources of emissions, indirect emissions from the facilities generating the electricity would still occur such as coal fired power plants.
- Additional co-generation facilities would likely have to be built in the region to supply the amount of electrical power needed for this option. This would result in additional emissions of criteria pollutants from the combustion of natural gas for turbines typically used for co-generation facilities.
- There would need to be possible upgrades in the electrical distribution system. However, the limitation of doing so is predicated by the electrical grid that would exist in a given area to provide the necessary capacity to support electrical compression

Burdens

- The cost to replace natural gas fired engines with electrical motors would be borne by the oil and gas industry.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary, depending upon the results of monitoring data over time.
B. Indicate the most appropriate agency(ies) to implement: State Air Quality agencies.

III. Feasibility of the option

A. Technical: Feasible depending upon the electrical grid in a given geographic area
B. Environmental: Factors such as federal land use restrictions or landowner cooperation could restrict the ability to obtain easements to the site. The degree to which converting to electrical motors for oil and gas related compression is necessary should be a consideration of the Cumulative Effects and Monitoring Groups. Indirect emission implications for grid suppliers should be considered (e.g., coal-fired plants).
C. Economic: Depends upon economics of ordering electrical motors, the ability of the grid system to supply the needed capacity and the cost to obtain right of way to drop a line to a potential site.

IV. Background data and assumptions used

The background data was acquired from practical application of using electrical motors in the northern San Juan Basin based upon interviews with company engineering and technical staff.

V. Any uncertainty associated with the option

Medium based upon uncertainties of obtaining electrical easements from landowners and/or land management agencies.

*A cumulative emissions inventory on all oil and gas field equipment is necessary
*If possible, a calculation of pollution related to electric power generation is needed for comparison to pollution emitted from gas powered engines.

VI. Level of agreement within the work group for this mitigation option

TBD.

VII. Cross-over issues to the other source groups

Oil and Gas Work Group
Cumulative Effects Work Group
Power Plant Work Group

OVERARCHING: CROSSOVER OPTIONS

Mitigation Option: Economic-Incentives Based Emission Trading System (EBETS) (Reference as is from Oil and Gas: see Oil and Gas Overarching Section)

Mitigation Option: Tax or Economic Development Incentives for Environmental Mitigation (Reference as is from Oil and Gas: see Oil and Gas Overarching Section)

FOUR CORNERS AREA POWER PLANTS FACILITY DATA TABLE

This data table was prepared by the Power Plants Work Group as a resource to help develop mitigation options. Facility data information was compiled from a variety of sources (see references). The last update of the table was August 2007. The Table, along with other resource information on Four Corners area power plants, is also available on the Task Force Website on the Power Plants Work Group Page, http://www.nmenv.state.nm.us/aqb/4C/powerplant_workgroup.html

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010 [10]
San Juan Generating Station [1]	PNM Resources (Owner/Operator)	Coal	ARP, EPA 9, Western Systems Coordinating Council	NMED - AQB	4 units, 1798 MW	PM- ESP	PM – 673 tons (2005)		PM – baghouse	13,097,406 tons (2005)	PM - 670 tons/yr
						SO_x - Wet Limestone	SO_2 – 16,570 tons (2005)	SO_2 – 16,179.3 tons (2004), 16,569.5 tons (2005) [4]	SO2 – enhanced scrubbing		SO2 - 8,900 tons/yr
						NO_x – Low-NOx burners / Over-fired air	NO_x – 26,809 tons (2005)	NO_x – 26,880.2 tons (2004), 26,809.0 tons (2005) [4]	NO_x – low-NO_x burners/ over-fired air / neural net		NOx - 18,500 tons/yr
						Hg – Wet scrubber	Hg – 766 lbs (2005)	CO_2 – 13,147,181.0 tons (2004), 13,097,410.1 tons (2005) [4]	Hg – activated carbon. Hg – CEMs		Hg - 275 lbs/yr
Four Corners Power Plant [2,3]	Arizona Public Service Company (Owner/Operator)	Coal	ARP, EPA 9	EPA Region 9, Navajo Nation EPA	5 units, 2040 MW	Units #1 - #3:	PM – 1,187 tons (2000-2005 annual average)		Considering available technologies for future regulatory changes [3]	15,913,105 tons (2000-2005 annual average)	N/A
						PM - Wet venturi scrubbers	SO_2 – 12,500 tons (2005)	SO_2 – 18,771 tons (2004), 12,554.2 (2005) [4]			

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010
Four Corners Power Plant [2,3] (cont.)						SOx - Dolomitic lime wet scrubbing	NO_x – 42,000 tons (2000-2005)	NO_x – 40,742 tons (2004), 41,743.4 tons (2005)			N/A
						NO_x – Low-NOx burners	Hg – Approx. 550-600 lbs/yr	CO_2 – 15,106,255 tons (2004), 16,015,408.7 tons (2005) [4]			
						Hg – Venturi scrubber					
						Units #4 & #5:					
						PM – Baghouses					
						SOx – Lime slurry wet scrubbing					
						NOx – Low-NOx burners					
						Hg – Wet scrubber, baghouses					
Proposed Desert Rock Energy Facility [5, 12]	Sithe Global Power, LLC (proposed owner/operator)	Coal		EPA Region 9, Navajo Nation EPA	2 units, 1500 MW [5]	PM – Baghouse [6, 12][1]	PM (TSP/PM) – 570 Tons/yr [6,12][3]		Hg – activated carbon if control < 90% and cost < $13,000/lb**	Approx. 12,700,000 tons/yr[8]	N/A
							PM_{10} – 1,120 Tons/yr [6, 12][4]				
						SOx –Wet Limestone FGD [6, 12][1]	SO_2 – 3,319 Tons/yr [6, 12]				
						NOx – low-NOx burners/ over-fired air / SCR [6,12]	NO_x – 3,325 Tons/yr [6, 12]				

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010
Proposed Desert Rock Energy Facility [5, 12] (cont.)						Hg – SCR +baghouse +FGD[2] [6, 12]	Mercury – 114 lbs/ yr [12]				N/A
							CO – 5,529 Tons/yr [12]				
						Hydrated Lime Injection & Wet Limestone FGD [12]	Lead – 11.1 Tons/yr [12] Flourides – 13.3 Tons/yr [12]				
						Hydrated Lime Injection & Wet Limestone FGD [12]	H_2SO_4 – 221 Tons/yr [12]				
Bluffview Power Plant [4]	City of Farmington (Owner/Operator) (Started 28-JUL-05)	Pipeline Natural Gas / Cogeneration	ARP, EPA 6		60 MW	Dry Low NOx Burners, Selective Catalytic Reduction		SO_2 – 0.7 tons/yr (2005) [4]		145997.3 tons (2005) [4]	N/A
								NO_x – 58.5 tons/yr (2005) [4]			
Milagro [4]	Williams Field Services (Owner/Operator)	Pipeline Natural Gas / Cogeneration	ARP, EPA 6		2 units, 61 MW [11]			SO_2 – 2.6 tons (2004), 2.5 tons (2005) [4]		498823.3 tons (2005) [4]	N/A
						NO_x – Dry Low-NOx burners		NO_x – 97.6 tons (2004), 110.2 tons (2005) [4]			

Facility	Operator	Fuel	EPA Programs / Region [4, 10]	Regulator	MW	Present Control Technologies	Emission Inventory Data	EPA Acid Rain Program Data and Maps [4]	Planned Facility Upgrades	Greenhouse Gas Info (CO_2)	Estimated Emissions after upgrades 2010
Animas Power Plant [9]	City of Farmington (Owner/Operator)	Pipeline Natural Gas / Cogeneration	EPA 6, Western Systems Coordinating Council		51 MW [9]		SO2 – 0 (2005, turbine only) NOx – 54 Tons (2005, turbine) VOC – 54.3 Tons (2005, turbine) CO – 5.1 Tons (2005, turbine)				N/A
Bloomfield Generation [4]	Ameramex Energy Group, Inc. (Owner/Operator)		ARP, EPA 6								N/A
Navajo Dam Hydro Plant [9]	City of Farmington (Owner/Operator)	Water			30 MW [9]						N/A
Mustang Energy Project[7][5]	Proposed	Coal			300 MW		PM - 185 tons/yr SO_2 – 250 tons/yr NO_X - 125 tons/yr			Approx. 2,000,000 tons/yr[8]	N/A

[1] May 23, 2006 edit, info provided by Mike Farley (PNM), and in SJGS presentation for 4CAQTF, "SJGS Emissions Control Current and Future" http://www.nmenv.state.nm.us/aqb/4C/Docs/SanJuanGeneratingStation.pdf
[2] http://www.aps.com/general_info/AboutAPS_18.html [dl 5/29/06]
[3] APS Four Corners Power Plant tour handout (received 5/10/06), supplemental info provided by Richard Grimes (APS), in May 31 table edit
[4] EPA Clean Air Markets – Data and Maps Query (2004 2005 2006 Facility & Unit Emissions Reports)

[5] SITHE GLOBAL Desert Rock Energy Project FACT SHEET #1 DEC 2004 [dl 5/29/06]
[6] Application for Prevention of Significant Deterioration Permit for the Desert Rock Energy Facility, prepared by ENSR International May 2004
[7] Reference to Dave R. edits 6/2/06
[8] Desert Rock Energy Project Draft EIS Ch. 4.0 – Environmental Consequences May 2007
[9] Farmington Electric Utility Fact Sheet http://206.206.77.3/pdf/electric_utility/feus_fact_sheet.pdf (6/16/06) / NMED
[10] Info provided by Mike Farley (PNM)
[11] http://www.emnrd.state.nm.us/EMNRD/MAIN/documents/SER1_electricity.pdf
[12] AMBIENT AIR QUALITY IMPACT REPORT (NSR 4-1-3, AZP 04-01), Table 1, EPA Region 9 Air Programs: http://www.epa.gov/region09/air/permit/desertrock/#permit

[1] Subject to BACT - Best available control technology [6]
[2] Mercury (Hg) and HCL have been targeted under future regulation under maximum available control technology (MACT) [6]
[3] PM is defined as filterable particulate matter as measured by EPA Method 5.
[4] PM10 is defined as solid particulate matter smaller than 10 micrometers diameter as measured by EPA Method 201 or 201A plus condensable particulate matter as measured by EPA Method 202. EPA is treating PM10 as a surrogate for PM2.5.
[5] Outside of Scope of Work, Not located in 4CAQTF study area

POWER PLANTS: PUBLIC COMMENTS

Power Plants Public Comments

Comment	Mitigation Option
I have been concerned for many years about the air quality of the Four Corner's region because of the coal fired power plants in N.M. I attended two of the Four Corner's air quality forums in the past and was disturbed by their reports. As a nurse, I am especially concerned for the health of the Native Americans and other people who reside close to the power plants because of their incidence of lung disease. As a resident of La Plata canyon for 20+ years with a high mercury level, I am concerned about my own health and notice more air pollution, lack of visibility, every time I hike in the mountains. I believe for everyone's health, alternative sources of energy; e.g. solar, wind energy is a much better solution and would still serve as a revenue source to the Navajo nation. Desert Rock should not be built and the others should be phased out as planned many years ago or at least upgraded to standards that were set by the Clinton administration.	General Comment
We do NOT need another power plant in the 4 Corners. I notice the dirty air in this area all of the time and especially on weekends. Drive up from Albuquerque and see the air get dirtier. Also, go out from the 4 Corners and notice the beautiful blue skies as you progressively leave the area. I teach school and stress to my students they need to take care of the this planet earth because there is no spare earth. I would like to stress to everyone else that this needs to be done. Solar, wind and other energy sources should be used.	General Comment
It saddens me and concerns me for our children's futures and the native American leaders who think that this is progress and prosperity for their people. The leaders are once again selling out their people for the promise of temporary jobs and profits. How can we as a educated people agree to allow this plant in today's environment? Mercury in our children's blood and more carbons in the air are a horrible price to pay for short term gains in energy downstream. How can Governor Richards speak of the environment while he is silent on this issue. I will not be able to attend any public meetings and would appreciate my view forwarded if possible. I am a mother, grandmother and previous medical office manager. Most importantly, I am a voter.	General Comment
It breaks my heart to think that another coal fired plant may be added to our "pristine" 4 corners area. Even in Pagosa Springs we have some hazy smog some days, and when driving south and west of Farmington, that horrible yellow-brown cloud can be seen for miles! I was shocked to see that poisonous cloud in Monument valley, and northwest Utah. It's all pervasive now so I can't imagine what it will be like with more coal -spewing plants. We must use non polluting energy sources for the health of all of us!	General Comment

Comment	Mitigation Option
Desert Rock Energy LLC (Desert Rock) appreciates the opportunity to submit the following comments on the Four Corners Air Quality Task Force Draft Report. Desert Rock supports the Task Force's efforts to promote air quality mitigation in the Four Corners area. Desert Rock is committed to air quality mitigation, and has designed the proposed Desert Rock Facility to minimize impacts while providing needed electricity and additional economic development to the Navajo Nation. As detailed in the Draft Task Force Report, the proposed Desert Rock Facility is a 1,500 MW mine mouth power plant being developed by Sithe Global Power, Desert Rock Energy Company, and the Dinè Power Authority (an enterprise of the Navajo Nation). It is designed to burn low BTU, low sulfur subituminous Navajo coal. The plant will be located at an elevation of 5,415 feet. It will be one of the most efficient plants in the US, with two supercritical pulverized coal-fired boilers operating at a net heat rate of 8,983 Btu/kWh. The plant will be required to operate with very low emission rates, including 0.06 lb/MMBtu for both NOx and SO2 and 0.01 lb/MMBtu for filterable PM, all on a 24-hour average. The plant will also use dry cooling to reduce water consumption by 80 percent. EPA has stated that the Desert Rock Facility will have the lowest emission rates of any coal-fired project in the US. These emission rates will be even lower than emission rates associated with IGCC. Desert Rock is committed to engaging in regional air quality improvement initiatives. In fact, Desert Rock has already invested significant time and resources participating in such initiatives. Desert Rock has worked with the National Park Service, the National Forest Service, EPA, the Navajo National Environmental Protection Agency, and other governmental stakeholders to create a mitigation plan that will offset all SO2 emissions from the facility and further reduce mercury impacts. Below is a description of this regional effort: 1. Desert Rock Energy has agreed to a Voluntary Regional Air Quality Improvement Plan with the US EPA, US Forest Service, National Parks Service, and the Navajo Nation Environmental Protection Agency. 2. The Improvement Plan requires Desert Rock to reduce regional SO2 emission and visibility impacts by one of three (3) mechanisms: 1) Regional SO2 Control, 2) Regional NOx Control, or 3) Procurement and retirement of SO2 Allowances. a. Under an SO2 control-sponsored project, the implementation of this plan will result in a net improvement of the local environment. The plan, not only will totally offset the SO2 emissions of Desert Rock (3,315 tons of SO2), it will also remove an additional 330 tons of SO2 from the local atmosphere, for a total reduction of 110%. b. If an SO2 control project cannot be developed, Desert Rock may implement a NOx control-sponsored project which will remove NOx emissions in the region by 100% of Desert Rock NOx emissions plus approximately an additional 7500 tons. c. If Desert Rock is not able to invest in capital projects at other plants to reduce SO2 or NOx emissions, Desert Rock has reserved capital to purchase and retire up to $3,000,000 per year in SO2 allowances for the life of the project. The acquisition of these allowances is beyond those that are required under the Acid Rain program.	General Comment

Comment	Mitigation Option
3. Mercury control of at least 80% will be achieved. Additional investments in Mercury control technology to reach a target of 90% control will be made subject to plan limitations. If the 90 % control target is met, it will reduce mercury emissions an additional 50 percent from approximately 160 lbs per year to approximately 80 lbs per year. 4. The local area will benefit from Desert Rock's annual environmental contributions that may be available subject to plan limitations. Such contributions could be used to advance the local environmental science and planning as well as sponsor projects that reduce greenhouse gas emissions, add further mercury control, increase monitoring, support the Four Corners Task Force, or contribute to any other environmental project determined to be of great value to the region. Desert Rock objects to the language in the Draft Report stating that "[t]he uncertainty [about the mitigation plan] involves how stakeholders can be assured the measures will actually happen." Desert Rock has made a public commitment to implement this mitigation plan and, in order to reassure all stakeholders of its commitment, is in the process of working with Federal agencies and the Navajo Nation to ensure that this mitigation plan is federally enforceable. The Desert Rock Facility will therefore be held accountable for fulfilling its mitigation commitments. In light of the mitigation plan, the Draft Report is incorrect in saying that "[w]hile the Desert Rock Energy Facility is using newer environmental emission control technology that on average have higher reduction efficiencies than existing facilities, the proposed power plant will still be adding substantial NO2, SO2, particulate, and other emissions to the Four Corners Area." It is quite likely that, because of the mitigation plan, either SO2 or NOx emissions in the area will actually be reduced. Although there will be a very small increase in emissions of other pollutants, the amounts are so small that the Plant will not have an appreciable impact on air quality in the Four Corners area. Discussion of CO2 Emissions Desert Rock believes that global climate change is a very serious issue and is committed to working with governments and industries to develop laws and policies - and most importantly, advanced technologies - that will reduce anthropogenic emissions of CO2 and other greenhouse gases. Indeed, as discussed below, we are actively exploring options that may allow us to capture and sequester CO2 emissions from the plant at some point in the future. We are concerned, however, about the discussion of CO2 emissions in the Draft Report. The Report is designed to address air quality issues in the Four Corners area, and it is simply misleading to suggest that CO2 is an air quality issue. CO2 emissions in New York and New Delhi will have precisely the same impact on climate change in the Four Corners Region as CO2 emissions from Desert Rock. By addressing CO2 without making a clear distinction between air quality (which is largely a local and regional issue) and climate change (which is entirely a global issue), the Report will actually be misleading to many readers who are not fully informed about the nature of climate change.	

Comment	Mitigation Option
IGCC and Desert Rock The Draft Report includes a discussion of Integrated Gasification Combined Cycle (IGCC) technology that is not appropriate for the Desert Rock Facility. We are concerned that it will mislead readers into thinking that IGCC would be a better environmental choice for the Four Corners area, when this is simply not the case. The EPA Report cited in the Report does not address the issues involved in building an IGCC plant (or a modern supercritical pulverized coal plant) with the type of coal available in the Four Corners area or at an altitude anywhere near the elevation of the Desert Rock Facility. Not only technical experts with Desert Rock Energy, but other technical experts have concluded that there would be serious technical challenges involved in trying to operate an IGCC plant at a site like the Desert Rock Facility. The Report suggests that, at a minimum, Desert Rock should have been required to evaluate IGCC as part of the BACT process. Desert Rock did, in fact, evaluate the potential use of a range of modern coal technologies including IGCC. Nothing more would be learned by formally including such an evaluation in the BACT process. Desert Rock determined that the use of modern supercritical pulverized coal boilers is the best option, not only in terms of cost and reliability, but from an environmental standpoint as well. This technology is proven, reliable, and highly efficient and, in combination with an extensive array of pollution control equipment, will be a leader in reducing emissions from coal combustion. EPA has again stated that the Desert Rock Facility will have the lowest emissions rate of any coal-fired project in the US. As discussed below, there would be no material difference in emissions - including CO2 and other green house gas emissions - with an IGCC plant at the Desert Rock site assuming current IGCC technology performance. Though IGCC is an evolving technology, IGCC does not currently meet the need for reliable and economical power production. There are only four operating coal-fired IGCC plants in the world, two in the United States both which use petroleum coke and not coal as the fuel source. Other IGCC projects in the US were built as small scale (less than 300 megawatts) demonstration projects with substantial government funding and some faced such severe operating problems that they never reached commercial operation. Even the facilities that did achieve commercial operation have not met projections for cost, efficiency, reliability and environmental performance. The "next generation" of IGCC plants, currently in development, with commercial operation dates planned in the 2011-2015 period, are in the 300-600 megawatt range. It remains to be seen if the next generation of IGCC plants will meet the cost and reliability targets needed to provide reliable, low cost power. There are also many engineering issues that remain to be solved in using low BTU high ash coals such as those found in New Mexico to fuel IGCC plants. Reliability - The IGCC units currently in operation have a poor reliability records. It remains to be seen if the next generation of IGCC plants will face similar reliability issues. The "integrated" part of IGCC refers to the integration of a gasifier and a combined cycle power plant to transform the	

Comment	Mitigation Option
coal into syngas and combust that syngas to produce electricity. This integration introduces numerous additional potential engineering points of failure and, as a result, there is a record of poor performance. Several of the IGCC units in operation have been able to reach the 80% reliability level but only after five to ten years of operation. In contrast, supercritical technology proposed for Desert Rock has a proven performance record of 90% or better, beginning in its first year of operation. Cost - Projections of life cycle capital and operating costs for IGCC plants in the 600 to 2,000 megawatt range are substantially higher than supercritical technology. These have demonstrated that the cost of a 1,500 megawatt IGCC plant is approximately 30-40% higher than a similarly-sized supercritical pulverized coal plant. Desert Rock would cost $1 billion more built using IGCC technology. Efficiency - The technology proposed for the Desert Rock Facility is highly efficient, meaning substantially less coal is used to produce the same amount of electricity with fewer emissions than older, conventional coal fired power plants. Desert Rock's proposed technology is also more efficient than current IGCC plants. For example, the technology proposed for the Desert Rock Facility is approximately 15% more efficient than the present IGCC facilities in Florida and Indiana, meaning it will use 15% less coal to produce a similar amount of electricity on an average annual basis. In comparison to recently filed air permit applications for the "next generation" IGCC plants, the Desert Rock Facility will have comparable efficiencies when the IGCC efficiency losses of operating at above 5,000 ft above sea level are taken in account. Emissions - Due to the high efficiency of the Desert Rock Facility's generating technology and the extensive array of pollution control equipment incorporated into its design, the plant's emission rates compare very favorably to existing IGCC units and are expected to be similar to the "next generation" IGCC plants. IGCC plants do not produce any less greenhouse gasses than a supercritical plant with similar efficiency Desert Rock is also designing the facility to have "future proofing" characteristics, which allow for augmentation of the initial extensive array of emissions control equipment and with more advanced control equipment when the new equipment is demonstrated to be commercially viable. Summary on IGCC - Desert Rock carefully considered all options available before concluding that supercritical pulverized coal technology is the best choice for the facility. The Desert Rock Facility's supercritical design helps to ensure a reliable power supply and lower fuel cost for customers, while being highly protective of public health and the environment. While IGCC is expected to become a viable large scale electric generation technology in the future, it currently lacks the reliability, efficiency, economics, and scale that supercritical technology provides with no material difference in emissions including greenhouse gases Carbon Sequestration and Desert Rock Sithe Global Power, LLC continues to study the technological and commercial implications of carbon capturing and sequestration (CCS) in	

Comment	Mitigation Option
power plant applications. With respect to the Desert Rock Facility, we have participated in numerous discussions with the Department of Energy, various national laboratories, and the major equipment suppliers to evaluate the technological feasibility and economic viability of a large scale CCS project. After extensive discussions, we have been unable to identify a commercially feasible solution. As of today, the major equipment suppliers are unwilling to offer performance guarantees for a large scale CCS project. In addition, an appropriate mechanism to recover the cost of implementation, including the cost of development, installation and operation, has not yet been implemented. As a result, Desert Rock is not in a position to incorporate CCS at this time. Desert Rock intends to continue to participate in the development of CCS and will consider the implementation of CCS once the technology and commercial framework are in place. The major equipment suppliers have an economic incentive to complete the development of the necessary technology. The Task Force can provide a great deal of assistance to help create and promote an appropriate commercial framework. Thank you for the opportunity to provide the above comments on the Draft Task Force Report. Desert Rock is again committed to air quality mitigation and appreciates the Task Force's efforts. If you have any questions or we can be of assistance, please let us know. Sincerely, Dirk Straussfeld Executive Vice President Desert Rock Energy Company, LLC Three Riverway Suite 1100 Houston, Texas 77056 Phone: (713) 499-1155 Fax: (713) 499-1167	

Comment	Mitigation Option
A Mitigation Option should be added for Nuclear technology. We should not assume that it is too controversial for consideration. The U.S. Nuclear Regulatory Commission is staffing up to consider up to 30 nuclear units in fiscal 2008. This was motivated by the Energy Policy Act of 2005, that has invigorated the power industry to come forward with new plans. A new NRC office has been created solely for licensing and oversight of new reactor activities, with a current staff of 240. The most activity for these units will be in the south and southeast, where utilities have on-going nuclear experience. NRC has streamlined their processes so standard design certifications would be approved, and the safety design hurdle would not be raised continually. Most of these applications will be active pump/valve cooling designs that meet the stringent safety requirements of standard design certifications. There is promise for a family of passive cooling reactors, where gravity/density differences provide equivalent cooling protection. These designs would be simpler and less expensive than current active pump designs. Much design work has been done, although there is not currently such a unit in operation. Nuclear plants have lower maintenance costs (about 1.7 cents per kwh, v.s. 3 - 5 cents for a fossil fuel units). Operating experience has advanced greatly over the 30 years since Three Mile Island, with plants running at 90% capacity -- up from 70% in the 1970s. Benefits: Zero air emissions impact; No carbon footprint; cost effective electricity generation; foster high technology employment basis in Four Corners; proximity to future Nevada spent fuel storage site Tradeoffs: Negative public opinion; spent fuel containment Reference: Energybiz magazine Vol. 4, Issue 3 (May 07, June 07) "Agency Gets Ready for Nuclear Renaissance" -- "Repackaging the Nuclear Option" -- "GE Gears Up"	Proposed Power Plant - Desert Rock Energy Facility
I feel this (and perhaps one or two other power plants options) should be incorporated by reference into the monitoring section. There is a lot of good writing here.	Negotiated Agreements in Prevention of Significant Deterioration (PSD) Permits
The monitoring of degrading power plants deserves dual attention; both in this section and in the monitoring section for emphasis.	Negotiated Agreements in Prevention of Significant Deterioration (PSD) Permits
The Electric Power Research Institute (EPRI) today announced the beginning of a new project to study the feasibility of concentrating solar power in New Mexico. Unlike conventional flat-plate solar or photovoltaic panels, concentrating solar power (CSP) uses reflectors to concentrate the heat and generate electricity more efficiently. There are four utility-sized CSP plants in the U.S. today; one in Nevada and three in California. Initiated by New Mexico utility PNM and with subsequent interest from other regional utilities, the project will be directed and managed by EPRI. PNM has expressed interest in building a CSP plant in New Mexico by 2010. The feasibility study for a power plant of the 50-500 megawatt (MW) size range is expected to be finished by the end of 2007. The Four Corners area is one of the best areas for solar energy production in the United States and would be an ideal location for a new solar energy plant. For example, in Farmington,	Utility-Scale Photovoltaic Plants

Comment	Mitigation Option
NM a flat-plate collector on a fixed-mount facing south at a fixed tilt equal to latitude, sees an avg. of 6.3 hours of full sun. The Solar plant could help New Mexico meet renewable energy portfolio standards. San Juan County also has a renewable energy school focusing on solar energy system design and installation. The plant could potentially be an educational/technical resource for the college.	
I would emphatically like to see this option included in the final report.	Reorganization of EPA Regions
The need for these studies is obvious and the cost should be passed on to the utilities (and therefore the customers). However, even if these new studies find a significantly negative relationship between chronic respiratory disease and air pollutants, we already have proof that air pollutants increase the incidence of asthma. This mitigation option should include plans to utilize the study results for actively engaging policy-makers and changing regulations and enforcement, especially in geographic hot spots.	Chronic Respiratory Disease Study for the Four Corners area to determine relationship between Air Pollutants from Power Plants and Respiratory Health Effects

Other Sources

Other Sources: Preface

Overview

The Other Sources Work Group was charged with analyzing emissions mitigation strategies from all industrial, residential and transportation sectors that have emissions that significantly impact air quality in the Four Corners region. Although the work group was small, participation in the group involved state, local and tribal air quality agencies, industry representatives, public citizens, and representatives of environmental organizations.

Organization

The members of the Other Sources Work Group decided to focus on four main topic areas:

1. Transportation, including mobile sources
2. Land use, development, and planning
3. Burning
4. Alternative energy and fuels

Mitigation options for transportation issues included the following: including multi-modal transportation options in the 2035 transportation plan, including the Four Corners region into the Clean Cities designation for the Western Slope, encouraging local organizations to push for new projects and ordinances for transportation issues, developing requirements for anti-idling, school bus retrofits, increasing taxes for dirtier vehicles, developing a regional inspection and maintenance program, retrofitting or replacing oil and gas fleet vehicles, and looking at the Reid vapor pressure of fuels.

For land use, development and planning, the group discussed the consistency of regulations between jurisdictions for construction and sand and gravel operations, developing a regional planning organization for the region, phasing of projects to minimize blowing dust from bladed tracts of land, and developing a fugitive road dust plan.

Burning is handled very differently among the different jurisdictions in the Four Corners region. Mitigation options discussed for burning included public education and outreach, regulating agricultural burning in the Colorado portion of the region, providing a subsidy for cleaner fuels for residential heating, and using filter traps on wood stoves.

The alternative energy and fuels options were developed in conjunction with the Power Plants work group, and are included in the Energy Efficiency, Renewable Energy and Conservation section of this document.

Mitigation Option: Phased Construction Projects

I. Description of the mitigation option
Construction projects remove large quantities of vegetation leaving bare earth open to wind erosion, as well as to other environmental and biological degradation. Phasing these projects, large and even single residential development could lessen this environmental problem. Phasing re-vegetation would also result in decreased wind erosion.

Since phasing includes both small and large projects, this is something that individuals can have a part in as well as participating in for the larger community.

Benefits:

- Air quality – Particulate matter would decrease, protection of scenic views and economic benefits for tourism

- Environmental – Globally desertification is a big concern. The decrease in wind-blown particulates could delay man-made local desertification.

- Economic—construction would be phased according to building. Therefore, upfront costs would be also coordinated with sales, rather than all at the project beginning. Construction loans would also be phased.

Burdens:

- Developers may see change in methods as a threat to free enterprise.

- Construction managers would have to keep grading machinery on site locations throughout the project.

II. Description of how to implement

A. Mandatory or voluntary

Both. Mandatory for new construction. Incentives for individual homeowners to plant vegetation on disturbed sites.

B. Indicate the most appropriate agency(ies) to implement

Counties and towns in land use regulations, building permits. Local and state agencies may also implement programs for free compost or vegetation (e.g., native trees or shrubs for lot sizes over 1 acre).

III. Feasibility of the option

A. Technical – High
B. Environmental – High
C. Economic – High – may result in higher costs for construction projects in some areas.

IV. Background data and assumptions used

Help from monitoring work group to collect data downwind of

V. Any uncertainty associated with the option (Low, Medium, High) – Low

VI. Level of agreement within the work group for this mitigation option.

VII. Cross-over issues to the other source groups

Oil and gas and power plant work groups may look at phased development and revegetation for new projects.

Mitigation Option: Public Buy-in through Local Organizations to push for transportation alternatives and ordinances

I. Description of the mitigation option, including benefits and burdens.
Involve existing local organizations in supporting alternative transportation options. Go to meetings of existing organizations and discuss how they can help to promote clean air. Examples of the type of projects local organizations might support include bike paths, bike racks on buses, carpool lanes, and ride-share.

Benefits of applying this option might include reduced traffic congestion, reduction of fuel use, and boosts to local neighborhood economies. Burdens would be minimal though there may some tax increases may be necessary to fund the projects.

II. Description of how to implement
This would be a voluntary option. Agencies and task force members would implement by participation in local meetings. Publicity to encourage participation in organizations and support for alternatives might also be used. States could use these partnerships as early action compacts for State Implementation Plans.

III. Feasibility of the option
This option would be easy to implement because it is voluntary. While there may be some minimal cost for agencies to participate in local meetings it would be within their mission and a positive use of tax dollars.

IV. Background data and assumptions
The simplicity of this option requires no background analysis. It is assumed that individuals would make the effort to partner with local organizations.

V. Any uncertainty associated with the option
There is little uncertainty that this would be a viable and effective option.

VI. Level of agreement within the Work Group for this option
All work group members agree that this is a worthwhile option.

VII. Crossover issues to other workgroups
Involvement in planning for employee ridesharing may crossover to the Power Plant and Oil and Gas groups.

Mitigation Option: Regional Planning Organization for the Four Corners Region

I. Description of the mitigation option
The Four Corners region has a number of different jurisdictions and requirements. The air quality issues in the region are more widespread than local jurisdictions or agencies can address without working together as a regional planning organization (RPO). What occurs in one jurisdiction affects other jurisdictions, especially with respect to air quality. Although any one jurisdiction may have a very good program, that would be unlikely to have a widespread effect throughout the Four Corners region. The synergies of a region are much greater. In not duplicating efforts, costs will be lessened. States and local jurisdictions must be committed to the work of the RPO. RPO membership should be limited to those who have regulatory authority (e.g., towns, cities, counties, tribal governments, states).

II: Description of how to implement
Members could be appointed by local and/or state governments. Officers could be voted in by the members. Member entities would include the cities/towns of Durango, Farmington, Aztec, Cortez, Bloomfield, and Pagosa Springs; the tribes of Navajo Nation, Southern Ute, Ute Mountain Ute, Jicarilla Apache; and the counties of San Juan and Rio Arriba in New Mexico and Montezuma, La Plata and Archuleta in Colorado.

Meetings of the regional planning organization would be held on a regular schedule (perhaps quarterly) and open to the public. It is important that the governors of the Four Corners states support the organization. Local agencies would brief the governors and the state agencies on the need for a work of the organization. It is possible that this organization could be set up similarly to a Council of Governments organization. One way to begin the conversation to establish the RPO would be to ask the League of Women Voters or other task force members to present this idea to the Northwest New Mexico Council of Governments. Funding could be joint from states, tribes, local governments, and potentially EPA grants.

Another option would be to house this RPO within the Western Governors Association, perhaps similarly to the Western Regional Air Partnership with a scope limited to the Four Corners region.

III. Feasibility of option
If there are 2 or 3 local champions that are willing to dedicate time and energy, this could work. Also, support of the state agencies and governors would be critical.

IV. Background data and assumptions used Assume local governments will be willing to work together on these issues.

V. Any uncertainty associated with the option (Low, Medium, High) Medium, depending on local support.

VI. Level of agreement within the workgroup for this mitigation option Strong.

VII. Cross-over issues to other source groups
No, although it is similar in focus to the Overarching mitigation option on Reorganization of EPA Regions.

Mitigation Option: Develop Public Education and Outreach Campaign for Open Burning

I. Description of the mitigation option

This option involves the development of a public education and outreach campaign that would target the practice of open burning. The goals of this mitigation option are to 1) educate the public on the health dangers associated with open burning, 2) educate the public on the environmental/air quality damages of open burning, and 3) decrease the usage of open burning in the targeted communities.

Open burning is a more serious threat to public health and the environment than what was previously believed. Burning household waste produces many toxic chemicals and is one of the largest known sources of dioxins in the nation. Dioxins are highly toxic, long-lasting organic compounds that are extremely dangerous, even at low levels. Dioxins have been linked to serious health problems, including cancers and developmental and reproductive disorders. Other air pollutants such as particulate matter, sulfur dioxide, lead, mercury and hexachlorobenzene also affect adults and children with asthma or other lung diseases. Diseases related to the nervous system, kidneys and liver have also been linked to these pollutants.

II. Description of how to implement

A. Mandatory or Voluntary: This program would be a voluntary program hosted by local agencies or environmental groups.

B. Indicate the most appropriate agency(ies) to implement: Public Health, Environmental

III. Feasibility of the option

A. Technical: There are many similar open burning education campaigns present in Colorado, therefore it would not be difficult to receive technical support for the option.
B. Environmental: Since we are aware of the environmental dangers associated with open burning, there is much research available to use in educating the public.
C. Economic: Depending on the budget of the agencies, this program should not be prohibitive or expensive.

IV. Background data and assumptions used

1. Data on emissions from open burning was pulled from the EPA's Municipal Solid Waste Web site (www.epa.gov/msw)

V. Any uncertainty associated with the option (Low, Medium, High)

Medium

Mitigation Option: Automobile Emissions Inspection Program

I. Description of the mitigation option

Automobile emissions inspection/maintenance (IM) programs are a traditional mobile source strategy to control automotive emissions. They improve air quality through the identification and repair of high emitting vehicles. Vehicles that are repaired pollute less, improving air quality. They also get better fuel economy that contributes to reducing green house gas emissions.

Inspection/maintenance programs have been used to control automobile emissions since the early 1970s. They were originally used in New Jersey, Arizona and other states as early as 1974. They have been predominantly implemented in areas that are, or have been, out of attainment for ozone or carbon monoxide.

It is estimated that in urban areas, such as Denver or Albuquerque, motor vehicles contribute one-quarter to one-half of all the anthropogenic hydrocarbon and nitrogen oxide emissions, and three-fourths of the carbon monoxide emissions. Even in rural areas, automobiles can be a source for these emissions. Control of these emissions will reduce ozone concentrations, dependent on factors such as the NOx/HC ratio, amount of solar radiation, and meteorology/air mass movement and vertical mixing. Of importance is the fact that mobile source hydrocarbon emissions generally are higher in ozone reactivity (ability to make ozone) than other sources, such as natural gas production, thus may be important to control.

Table 1
2007 Denver metro VOC and NOx inventories
(tons per day)

	Mobile Inventory	**Total Inventory**
VOC	117.5	479.4
NOx	119.3	336.5

Source: CDPHE, Early Action Compact (EAC)

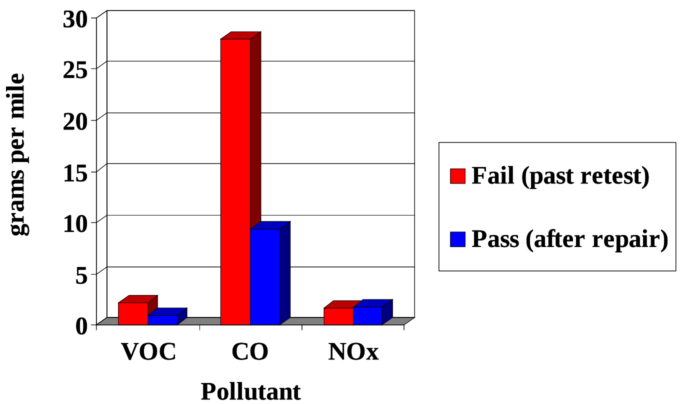
Repair Effectiveness

High emitting vehicles disproportionately contribute to mobile source emissions. Their repair is important in maintaining low overall mobile source inventories. Colorado inspection station data indicate that repairs to failing vehicles significantly reduce hydrocarbon emissions. Vehicles that failed their initial IM 240, and are later repaired, emit an average of 2.2 grams of hydrocarbons per mile. Upon passing a retest, these same vehicles emit an average of 1.0 gram of hydrocarbons per mile. This is a 57% reduction in the amount of hydrocarbons emitted by these vehicles.

Other emissions such as carbon monoxide, a weak ozone precursor, are similarly reduced. Motor vehicles that failed their initial IM 240 test, and are repaired, emit an average of 27.9 grams of carbon monoxide per mile. On a passing retest, these same vehicles emit an average of 9.4 grams of carbon monoxide per mile. This is a 66% reduction in the amount of carbon monoxide emitted by these vehicles. NOx emissions are not emphasized in Colorado's program and are basically unchanged. Adoption of tighter NOx emission cutpoints would result in greater NOx benefit.

The repair effectiveness results of Colorado's IM240 program are given in Figure 1.

Figure 1
2005 COLORADO IM240 TEST RESULTS
INITIAL FAILS VS FINAL PASSING TEST
ALL VEHICLES



On-Board Diagnostics

There are many different types of IM programs and IM tests. However, a simple cost-effective IM program is an on-board diagnostics (OBD) program, either as a stand-alone program for 1996 and newer model year vehicles, or one matched with an idle or other emissions test for 1995 and older vehicles. An OBD program can also be paired with an emissions test that measure a vehicle's emissions as well as examining their diagnostic codes. Examples of other emissions tests that may be paired with an OBD test are given in the attached appendix.

All 1996 and newer light duty vehicles are equipped with on-board diagnostics (OBD) technology. The intent of the OBD system is to monitor the vehicle's emissions control systems while the vehicle is in operation and detect potential problems as soon as they occur. Once a problem is detected, the system notifies the motorist by turning on a malfunction indicator light along with storing malfunction specific diagnostic information in the computer. The sensitivity of the system is programmed to detect a malfunction that may cause the vehicle's emissions to exceed 1.5 times its certification levels.

An OBD IM Program would require 1996 and newer model-year vehicles to undergo a periodic diagnostic check of all their stored trouble codes. If no malfunctions were identified the vehicle would pass. If malfunctions were identified, the vehicle would be required to be repaired. The following table identifies the IM benefit of an OBD-only program and an OBD program linked to an exhaust emissions test, in this case an IM240 test, for the Denver area fleet in 2007.

Table 2
OBD & OBD/IM240 Benefit
2007 Denver-Metro Fleet

	No I/M (gpm)		OBD only (gpm)	% Benefit		OBD w/IM240 (gpm)	% Benefit
HC	1.364		1.313	3.7		1.25	8.4
CO	13.627		12.832	5.8		11.959	12.2
NOx	1.392		1.334	4.2		1.315	5.5

Source: CDPHE, MOBILE 6 / 2007 Denver-metro fleet

<u>II: Description of how to implement</u>
An on-board diagnostics (OBD) program can be implemented as a contractor operated centralized IM program, or a decentralized inspection program, or decentralized inspection and repair program. State/local/or contractor staff would undertake program design, after authority for such a program is established through the state legislature and/or regulatory boards. Enforcement would be through state or local program enforcement staff. Registration denial would be the most effective way of maintaining program compliance.

<u>III. Feasibility of option</u>
An OBD program either with or without an emissions test is very feasible. Currently 32 states and the District of Columbia operate such a program, or will in the near future. Additionally, new innovative OBD features, such as self-standing, self-serve OBD kiosks, and loaner radio transponders are being implemented or are under development in Washington and California.

<u>IV. Background data and assumptions used</u>
Emission factors were generated by the U.S. EPA MOBILE 6b model. They reflect the Denver area fleet and transportation network for 2007. Repair effectiveness data is from the Colorado IM 240 program, and represents emission data derived from load-mode transient IM 240 testing. Inventories showing mobile source contribution are for the Denver metro area. Mobile sources' contribution is expected to be less in rural areas.

<u>V. Any uncertainty associated with the option (Low, Medium, High)</u>
Low. OBD Programs are proven strategies. A higher uncertainty exists for add-on elements such as implementation of self-standing, self-serve OBD kiosks, and loaner radio transponders. The greatest uncertainty is the integration of the data network with vehicle registration records and county clerk renewal processes. In states, such as Colorado, with existing IM Programs this is not an issue.

<u>VI. Level of agreement within the workgroup for this mitigation option</u> Good general agreement.

<u>VII. Cross-over issues to other source groups</u>
IM (inspection/maintenance) programs offer the ability to assist in controlling mobile source contributions to ozone formation, regional haze, air toxics, and global warming. There will be little cross-over issues with other groups. An IM program could affect gasoline vehicles used in oil and gas production, or other work covered by other groups, but generally there will be minimum cross-over.

As diesel vehicles and off-road vehicles are equipped with OBD features, they could conceivably be included in their own OBD programs. On-road diesels registered in the Front Range of Colorado currently participate in an opacity IM program.

Appendices

<u>Significant Emissions Tests</u>

On-Board Diagnostics
This technology is installed on 1996 and newer light-duty cars and trucks. It uses the vehicle's computer to identify potential emissions problems. If a problem exists, the system is required to warn the driver by displaying a warning light. Also, a "fault code" is simultaneously stored in memory identifying the problem area. Drivers are required to visit a test station periodically to have their vehicles "scanned" for fault codes This takes only a short amount of time. There is good accuracy in detecting potential problems with this test.

Idle Test
Initially used in New Jersey, Arizona and other states as early as 1974, emissions measurements take place while the engine is at the steady-state condition of idle. Over the years, minor changes were introduced and there are now six different idle test "types." Colorado first used this test in 1981 and still uses a modified version on heavy-duty vehicles, and older light-duty vehicles, in the Denver metropolitan program area. The major advantage of these tests is the relatively low equipment costs ranging from $15,000 to $20,000. The major drawback is a high level of false "passes" caused by newer technology on today's vehicles.

Acceleration Simulation Mode
In an attempt to increase accuracy, this newer class of steady-state test uses similar analytical equipment to the idle test, but also includes a dynamometer to "load" or "exercise" the vehicle at a constant speed. This test is designed primarily for states that are not in attainment for ozone.

A good example of the load applied to the vehicle during testing would be comparable to driving at a steady speed of 15 miles per hour on an eight percent grade hill, similar to the section of I-70 between the Morrison and Lookout Mountain exits, or at 25 miles per hour on a five percent grade hill, about half as steep as the previous example. The intent is to simulate an acceleration of the vehicle.

The two major positive elements of this test are the addition of nitrogen oxide emission measurements, and moderate equipment costs of $35,000 to $60,000.

Transient Tests
This class of test also utilizes a dynamometer but uses significantly more accurate analytical equipment and varies the vehicle speed during the inspection. The dynamometer load applied to the vehicle drive train is more similar to actual driving on a road. Test accuracy is the major positive element, with high equipment costs, often more than $100,000 being the major drawback. Because of the cost, transient tests usually are centralized due to economies of scale. The following major options are examples of transient tests.

IM 240
The IM 240 (Inspection and Maintenance, 240 seconds) is a shortened version of the Federal Test Procedure and is used in the Denver metropolitan program area. Vehicle speed is varied between 0 and 57 miles per hour. This test generally is considered to be the best predictor of the Federal Test Procedure.

IM 93
A shortened version of the IM 240, the IM 93 incorporates only the first 93 seconds. Top speed is approximately 36 miles per hour.

BAR 31
The BAR 31 (California Bureau of Automotive Repair, 31 seconds) is another loaded mode test, which has a maximum speed of 30 miles per hour and a driving time of 31 seconds, which can be repeated up to four times before failing the vehicle.

Other Predictive Options

Vehicle "Profiling"
Vehicle profiling runs in parallel with an existing inspection program. Using current inspection information, it is possible to predict whether a vehicle is likely to pass or fail based on the year, make and model. This increases the cost effectiveness of the inspection program by reducing the amount of resources needed for a full inspection test.

Low Emitter Profile
This method attempts to identify vehicles that are likely to be relatively "clean" vehicles or very low emitters. This can be done by analyzing current inspection data and predicting the probability that a certain year, make and model vehicle will pass the test.

High Emitter Profile
This method generally attempts to identify vehicles that are likely to be "dirty" or high emitters. Once identified, either through past inspection records of a specific vehicle, or because certain years, makes and models tend to be high polluters, targeted vehicles are subject to special treatment. Usually, this includes restricting the vehicle inspections to stations with higher quality control procedures and/or increasing the test frequency, e.g., substituting an annual inspection cycle for what would normally be a biennial cycle. Colorado does not use high emitter profiling in its inspection program.

Remote Sensing Clean Screen
Rather than trying to shorten or enhance a state's emission test, this technology attempts to "pre-screen" a vehicle as it drives by a remote sensing device placed on a roadside. If multiple readings indicate the car or truck is a low polluter, the vehicle owner is exempted for one test cycle from having to visit a traditional test station. The major benefit of this program is reduced inconvenience to owners of low polluting vehicles. A drawback is that some vehicles may be exempted that would normally fail the emissions test. However, by monitoring test conditions, this can be kept to a reasonable level that still meets air quality objectives. Additional issues are described in the body of this report.

Remote Sensing High Emitter Identification
As a vehicle drives by a remote sensing device, its emissions are measured. Vehicles with high enough emissions are required to come in for a confirmatory IM inspection.

Model Year Exemption
Another method of Low Emitter Profiling is exempting by model year. For instance, it is extremely unlikely that a new vehicle will fail an emissions test during the first few years from when it was manufactured. The case has been made that it is a waste of inspection resources and an owner's time to test those vehicles. Colorado exempts new cars from testing requirements for four model years.

Mitigation Option: Low Reid Vapor Pressure (RVP) Gasoline

I. Description of the mitigation option

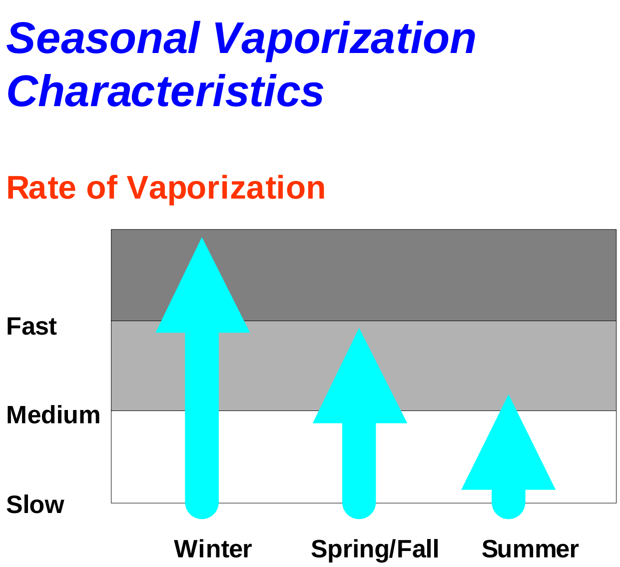
A major source of hydrocarbon emissions is the evaporative emissions produced by gasoline. Evaporative emissions occur during the refining process, through transportation and storage to the service station, and finally in refueling and operation of motor vehicles. The rate at which these emissions are produced is directly related to the fuel's volatility. The higher the volatility of the gasoline, the more volatile organic compounds (VOCs) are emitted at any given temperature.

One method to control gasoline evaporative emissions that contribute to ozone formation is to lower the volatility of gasoline, especially during the summer months. For most areas, summertime volatility is controlled by the U.S. Environmental Protection Agency (U.S. EPA). Under the Clean Air Act Amendments of 1990, the administrator of the U.S. EPA is charged with designating volatility standards for areas based on their air quality needs.

The U.S. EPA has set a gasoline volatility standard of 9.0 pounds per square inch (9.0 lbs.) for northern areas that meet the National Ambient Air Quality Standard for ozone. Air quality agencies with non-attainment areas may choose a different standard in their State Implementation Plan (SIP), or use the default standard set by the U.S. EPA.

Volatility outside the U.S. EPA controlled summer season (May 1st through September 15th) is generally controlled in most states by the American Society of Testing and Materials (ASTM) standards. These standards are set by national committees to reflect standards needed for good automotive operation and drivability.

Generally speaking, higher RVP is useful during the colder winter months to allow for easy cold weather starting and operation. Lower volatility is required during the warmer months, including summer, to prevent vehicle vapor locking and decreased drivability. The following chart shows this relationship.



SOURCE: Changes in Gasoline III

Air Quality Benefits of Lower Volatility Gasoline

As part of its efforts to reduce summertime ozone, the Denver area examined the benefits of lower volatility of gasoline. This analysis, part of Colorado's Early Action Compact (EAC) found that reducing gasoline RVP from 9.0 pounds per square inch (lbs.) to 8.1 lbs. would reduce mobile source evaporative emissions by 10 tons of VOC per day. Lowering gasoline volatility still further to 7.8 lbs. was found to reduce evaporative emissions by 13 tons of VOC per day. This represents a 7.8% to 10.2% VOC reduction in mobile source emissions.

Table 1
2007 Denver Metro VOC Inventories
(tons per day)

Reid Vapor Pressure	Mobile Inventory	Mobile Source Benefit	Total Inventory
9.0 lbs.	128	0	489
8.1 lbs.	118	10	479
7.8 lbs.	115	13	476

Source: CDPHE, Early Action Compact (EAC)

Cost

In examining the use of lower volatility gasoline to reduce VOC emissions, it was estimated that the price of gasoline would be expected to increase by one or two cents per gallon. For the Denver area it was estimated that this would equate to $8,600 per ton for 8.1 lb. RVP gasoline and $13,300 per ton for 7.8 lb. RVP gasoline. Because of high ozone measurements in the summer of 2005, and the fact that Denver had been originally been designated as a 7.8 lb. RVP area by the EPA administrator in the early 1990s (though had a received a series of waivers from this requirement), the U.S. EPA reestablished the 7.8 lb. RVP requirement for the Denver area starting with the summer of 2004.

Outside of the Denver area, all of Colorado continues to have a 9.0 lb. RVP maximum for gasoline sold between June 1st and September 15th. Most of Utah (outside of Davis and Salt Lake counties) also has this summer maximum, as does New Mexico and most of Arizona (outside of part of Maricopa County). The following chart, taken from EPA's report, "Study of Unique Gasoline Fuel Blends (Boutique Fuels) Effects on Fuel Supply and Distribution and Potential Improvements," U.S. EPA 2001, diagrams the various summertime fuel specifications for different regions of the U.S.

Summertime Gasoline Requirements

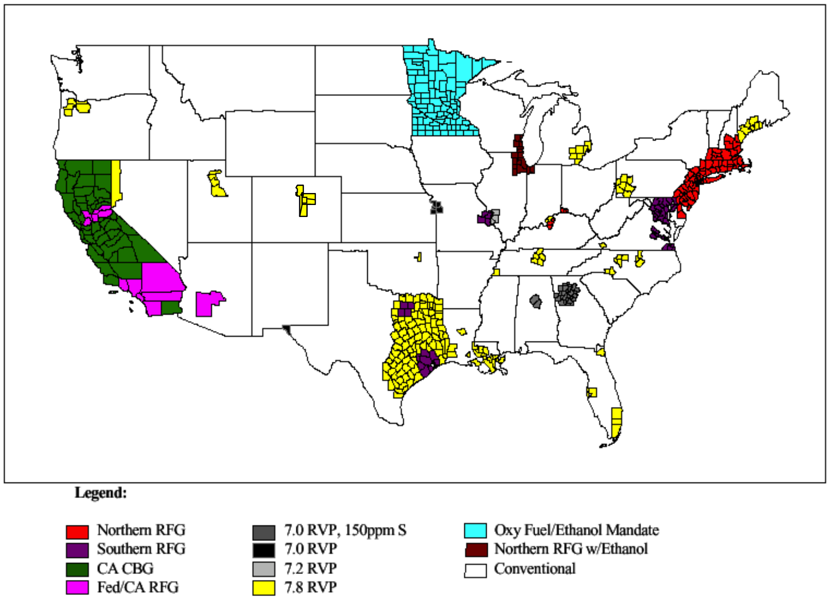


FIGURE II-1: Current Summer U.S. Gasoline Requirements

SOURCE: "Study of Unique Gasoline Fuel Blends ('Boutique Fuels'), Effects on Fuel Supply and Distribution and Potential Improvements" U.S. EPA Oct. 2001

<u>II: Description of how to implement</u>
Implementation of a low RVP program would be through State Implementation Plans. The various states would examine the options available, depending on air quality classification. If low RVP was required as a state program, the state would enforce the requirements. If it was an U.S. EPA program, the federal government would enforce.

<u>III. Feasibility of option:</u>
This option is fairly easy to develop and implement.

<u>IV. Background data and assumptions used</u>
A major assumption is that the Four Corners area will become nonattainment for summertime ozone, either as a result of elevated measurements, or the implementation of a new, lower, more rigorous ozone standard.

<u>V. Any uncertainty associated with the option (Low, Medium, High)</u> Low.

<u>VI. Level of agreement within the workgroup for this mitigation option</u> Good general agreement.

<u>VII. Cross-over issues to other source groups</u>
There does not seem to be much cross over.

Mitigation Option: Use of Reformulated Gasoline

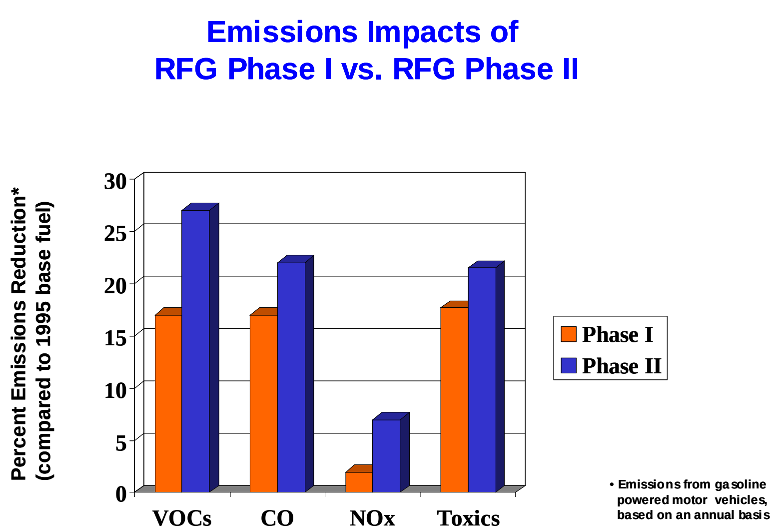
I. Description of the mitigation option

The use of reformulated gasoline (RFG) is an effective way of reducing ozone precursors from gasoline powered motor vehicles. Their use was first mandated in the nine most severe ozone nonattainment areas by the Clean Air Act Amendments of 1990. These areas included: Los Angeles, San Diego, Chicago, Houston, Milwaukee, Baltimore, Philadelphia, Hartford, and New York City. Others areas have since "opted" into the federal program. At last count, there are now 17 states and the District of Columbia that require its use. California implemented its own program beginning in 1992.

Reformulated gasoline is gasoline that has been reformulated to lower ozone precursors. While gasoline is generally formulated for the time of year or season, geographical location, altitude, and other conditions, reformulated gasoline is specifically formulated for emissions. Usually the distillation curve of the fuel (including Reid vapor pressure) is adjusted as well as other properties (light ends, olefin and aromatic content, etc.). By Clean Air Act requirement, an oxygenate, such as ethanol, is added. California reformulated gasoline goes an additional step in weighing hydrocarbon ozone forming reactivity in their performance-based standards.

Air Quality Benefits

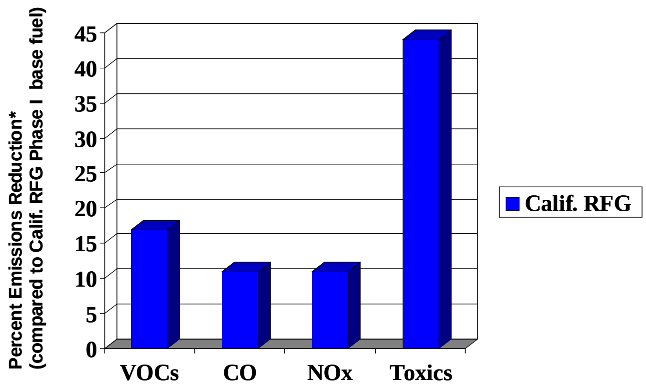
Under the original federal specifications, the use of federal Phase I reformulated gasoline (1995) was expected to reduce hydrocarbon and air toxic emissions by 15% compared to conventional gasoline. Phase II reformulated gasoline (2000) was mandated to reduce hydrocarbon and air toxic emissions by approximately 22%.



Source: US EPA,"Phase 11 Reformulated Gasoline: The Next Major Step Toward Cleaner Air", Nov 1999, except for air toxics, EIA/DOE

California (CA) reformulated gasoline is even a more stringent formulation. The latest Phase 3 reformulated gasoline standards, based on the CaRFG3 predictive model, are 11% to 17% lower in HC, CO, and NOx emissions and 44% for air toxics compared to the original Phase 1 specifications introduced in 1992, itself a low ozone and air toxics formulation with caps on olefin and benzene content.

Emissions Impacts of Calif. RFG Phase II/III vs. Calif. RFG Phase I



Source: Chevron: "Gas and Air Quality: Reformulated Gasoline", Chevron

California Phase 2 reform (introduced in 1996) was estimated by the California Air Resources Board (CARB) to be twice as effective as Phase I federal reform of the same era. Phase 3 reformulated gasoline is very similar to CA Phase 2 in emissions, but does not use methyl tertiary-butyl ether (MTBE), an oxygenate found to contaminate groundwater if released during fuel spills or leaks.

Cost

Reformulated gasoline is more expensive than conventional gasoline to produce (though this is less so with the implementation of federal Tier II conventional gasoline requirements beginning in 2005). The U.S. EPA estimated that Phase I federal reformulated gasoline typically cost between three and five cents per gallon more to produce than conventional gasoline, with Phase II reform costing an additional one to two cents. CARB estimated California reformulated Phase 2 gasoline to be between five and fifteen cents per gallon more expensive than conventional gasoline.

Supply issues come into play with reformulated gasoline. While most refineries can easily make it, their facilities may not always be optimized to produce it. California reform is even more subject to these limitations.

Approximately 30% of all gasoline now sold in the United States is reformulated. The following chart, taken from EPA's report, "Study of Unique Gasoline Fuel Blends (Boutique Fuels) Effects on Fuel Supply and Distribution and Potential Improvements," U.S. EPA, 2001, diagrams the various reformulated gasoline program areas, as well as summertime fuel specifications for different regions of the U.S.

Summertime Gasoline Requirements

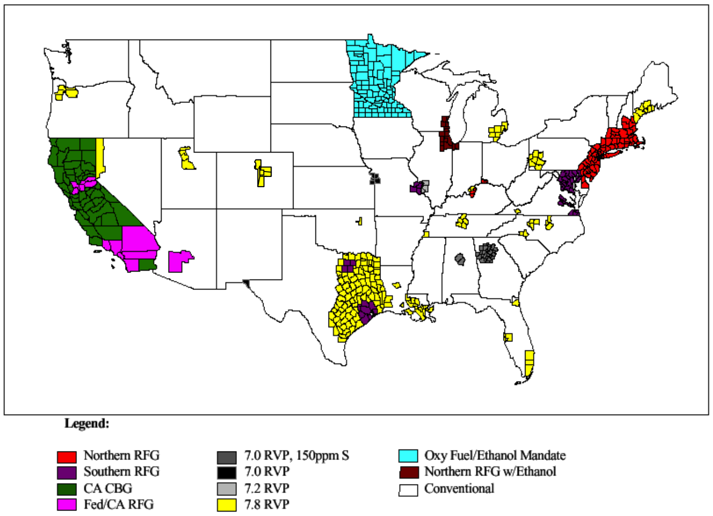


FIGURE II-1: Current Summer U.S. Gasoline Requirements

SOURCE: "Study of Unique Gasoline Fuel Blends ('Boutique Fuels'), Effects on Fuel Supply and Distribution and Potential Improvements" U.S. EPA Oct. 2001

II: Description of how to implement

Implementation of a RFG program would be through State Implementation Plans. The various states would examine the options available, depending on air quality classification. Typically a state will "opt" in to the federal reformulated gasoline program, with the federal government enforcing the program. If so desired the state may implement and enforce their own state RFG program. However, state programs must be identical to federal or California RFG programs.

III. Feasibility of option

This option is fairly easy to develop and implement.

IV. Background data and assumptions used

A major assumption is that the Four Corners area will become nonattainment for summertime ozone, either as a result of elevated measurements, or the implementation of a new, lower, more rigorous ozone standard.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium. The use of reformulated gasoline would require that there be available supplies. A major refiner close to the four-corners area, Valero's McKee refinery located in the panhandle of Texas, already manufactures reformulated gasoline for Texas and other reformulated gasoline markets. The question is whether it and other refineries have the capacity, at a reasonable cost, to produce enough RFG for the Four Corners area.

VI. Level of agreement within the workgroup for this mitigation option

Good general agreement.

VII. Cross-over issues to other source groups

There does not seem to be much cross over.

Mitigation Option: Idle Ordinances

I. Description of the mitigation option

Motor vehicle idling is a source of preventable mobile source emissions. Recognizing that most vehicles do not need to idle, many cities have passed local ordinances banning excessive vehicle idling, specifically for heavy-duty vehicles such as trucks and buses. Voluntary idling programs may also be used, especially for gasoline powered light-duty vehicles.

Most city ordinances set the maximum idling time at two to five continuous minutes. Some have longer time limits. In Maricopa County, Arizona the time limit is five minutes. In Denver and Aurora, Colorado the time limit is 10 minutes in any one-hour period. Philadelphia has a minimum two minutes. The Houston/Galveston nonattainment area has a minimum of five minutes from April 1st through Oct. 31st. Salt Lake City permits up to 15 minutes of continuous idling.

Emissions Reductions

Idling ordinances generally target heavier diesel trucks and buses and particulate (PM) emissions. However, there is no reason to preclude light-duty gasoline vehicles. All internal combustion vehicles emit pollutants and green house gases. It is estimated that larger trucks and buses burn from one-half to one gallon of fuel per hour of idling (1,2), all of which produce unnecessary emissions. Light-duty gasoline vehicle fuel consumption may be half to a quarter of this.

According to Air Watch Northwest, a consortium of air quality management agencies in Washington state, Oregon, and British Columbia (www.airwatchnorthwest.com), cars at idle emit a comparable amount of pollution to when it is driven (3). This is especially true when a vehicle is started cold, before its catalytic converter is warm enough to become effective. Once warm, a catalyst will stay warm for quite some time, so shutting down an engine to conserve fuel and limit emissions will generally have little effect on catalytic effectiveness when the vehicle is restarted.

The following tables list the average emission for vehicles at idle. The first two are for passenger cars and light trucks. The third table lists emissions for heavy-duty trucks and buses. Data is from April 1998. The acronyms used in the charts are listed below. All data is from U.S. EPA, and may be obtained at: http://www.epa.gov/otaq/consumer/f98014.pdf

LDGV	Light-duty gas vehicle
LDGT	Light-duty gas truck
HDGV	Heavy-duty gas vehicle
LDDV	Light-duty diesel vehicle
LDDT	Light-duty diesel truck
HDDV	Heavy-duty diesel vehicle
MC	Misc

U.S. EPA Estimated Idle Emissions
for Passenger Cars and Light Trucks

Summer Conditions (75 degrees F., 9.0 psi Rvp gasoline)

Pollutant	Units	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
VOC	g/hr	16.1	24.1	35.8	3.53	4.63	12.5	19.4
	g/min	0.269	0.401	0.597	0.059	0.077	0.208	0.324
CO	g/hr	229	339	738	9.97	11.2	94.0	435
	g/min	3.82	5.65	12.3	0.166	0.187	1.57	7.26
NOx	g/hr	4.72	5.71	10.2	6.50	6.67	55.0	1.69
	g/min	0.079	0.095	0.170	0.108	0.111	0.917	0.028

Winter Conditions (30 degrees F., 13.0 psi Rvp gasoline)

Pollutant	Units	LDGV	LDGT	HDGV	LDDV	LDDT	HDDV	MC
VOC	g/hr	21.1	30.7	44.6	3.63	4.79	12.6	20.1
	g/min	0.352	0.512	0.734	0.061	0.080	0.211	0.335
CO	g/hr	371	487	682	10.1	11.5	94.6	388
	g/min	6.19	8.12	11.4	0.168	0.191	1.58	6.47
NOx	g/hr	6.16	7.47	11.8	6.66	6.89	56.7	2.51
	g/min	0.103	0.125	0.196	0.111	0.115	0.945	0.042

U.S. EPA Estimated Idle Emissions
for Heavy –Duty Trucks and Buses

Engine Size	Emissions
Light/Medium HDDVs (8501-33,000 GVW)	2.62 g/hr (0.044 g/min)
Heavy HDDVs (33,001+ GVW)	2.57 g/hr (0.043 g/min)
HDD buses (all buses, urban and inter-city travel)	2.52 g/hr (0.042 g/min)
Average of all heavy-duty diesel engines	2.59 g/hr (0.043 g/min)

These average idle emissions may be compared to average vehicle emissions by comparing the first two tables with the table listed below. This data may be obtained at:
http://www.epa.gov/otaq/consumer/f00013.htm

U.S. EPA Emissions Facts
Average Annual Emissions and Fuel Consumption
for Passenger Cars and Light Trucks

Component	Car Emission Rate Fuel Consumption	Light Truck Emission Rate Fuel Consumption
HC	2.80 g/mi	3.51 g/mi
CO	20.9 g/mi	27.7 g/mi
NOx	1.39 g/mi	0.81 g/mi
CO2	0.915 lbs/mi	1.15 lbs/mi
Gasoline	0.0465 gal/mi	0.0581 gal/mi

As can be seen by a comparison of the above tables, for volatile organic compounds (VOCs), it will take eight minutes of idling to equal one mile of driving for an average automobile during the summer. For carbon monoxide (CO) this is approximately five and a half minutes, and, for nitrogen oxides (NOx) this is approximately seventeen and a half minutes.

Particulate Emissions
One reason to adopt idling ordinances or some voluntary program to reduce idling is the exposure to particulate emissions. One of the principle sources of particulate matter (PM) exposure is from diesel vehicles. This is of utmost importance when it comes to school-age children and their exposure to diesel school bus particulate and air toxic emissions. On average, children and adults may be exposed to excessive levels of PM from idling diesel trucks and buses. As the above table points out, an average heavy-duty diesel truck or bus will produce approximately 2.6 grams of particulates per hour. It should be noted that federal health-based PM standards are measured in the micrograms (not grams) range. The short term PM standard for PM_{10} is $150ug/m^3$ for a 24-hour average.

Technologies Used to Reduce Truck Idling
A number of strategies can be used to assist vehicles, mostly trucks and buses, from needing to idle while maintaining heating and cooling capacity. For larger trucks and buses, stand-alone direct-fired heating devices are available that cost from $1000 to $2000. Automatic engine idling devices may also be used that continue air conditioning when the engine is turned off at a cost of $1000 to $2000. Most expensively, small power generating auxiliary power units may be used, each costing from $5000 to $7000 (2).

At truck stops, fleet locations, and other stationary parking facilities, truck-stop electrification may be utilized. “Shore power” is provided directly to the parked truck, linking it to the power grid for all its electrical needs. This is estimated to cost $2500 per truck space and another $2500 per truck to modify so that it can receive the electricity (2).

References:
(1). U.S. EPA
(2). Philadelphia Diesel Difference Working Group
(3). Air Watch Northwest

II: Description of how to implement
Generally local government may adopt ordinances limiting vehicle idling, principally heavy-duty diesel truck or bus idling. School districts can modify their procedures to prevent excessive school bus idling. Trucking fleets, including oil and gas extraction fleets can also implement updated policies for their drivers.

Local air planning agencies, state, or local government can also implement voluntary programs, aimed at both light-duty gasoline vehicles as well as heavy-duty diesel vehicles. Voluntary programs can be established relatively easily and in a minimal amount of time. Infrastructure to promote auxiliary power for trucks to use at truck stops, distribution centers (think Walmart), etc., would take more time and money to accomplish.

III. Feasibility of option
This is a very feasible option. Idling ordinances and voluntary idling reduction programs have been established for a number of years in many locations.

IV. Background data and assumptions used
Emission estimates are generally those published by the U.S. EPA.

V. Any uncertainty associated with the option (Low, Medium, High)
Low. Idling ordinances and voluntary idling reduction programs are proven strategies.

VI. Level of agreement within the workgroup for this mitigation option
Good general agreement.

VII. Cross-over issues to other source groups
There will be little cross-over issues with other groups, except for fleets, such as involved in oil and gas extraction.

Mitigation Option: School Bus Retrofit

I. Description of the mitigation option

One of the most significant sources of particulate and air toxic exposures that young school-age children are exposed to are diesel school bus emissions. Older diesel school buses contribute a greater proportion of particulate (PM), as well as nitrogen oxide (NOx) and hydrocarbon (HC) emissions, compared to current buses built to the newest emission certification standards.

While the newest school bus emissions standards have just been implemented, school buses have long lives, permitting older higher emitting school buses to continue to expose children to high levels of diesel exhaust and to contribute to summertime ozone precursors. Reducing emissions from these buses will result in emission reductions that will last for years.

One method of reducing emissions from these older school buses is through school bus retrofit programs. Retrofit programs achieve their air quality benefit by improving the emissions characteristics of the existing school bus. Improvements may range from re-powering school buses with new replacement engines, or adding better emission control equipment, to using cleaner sources of fuel.

Emissions Reductions

PM Emissions

It is estimated by the U.S. EPA that oxidation catalytic converters retrofitted to buses reduce PM emissions by 20% to 30%, at a cost of $1000 to $2000 per bus(1). Retrofitting with a particulate trap reduces particulate matter by 60% to 90%, at a cost of $5000 to $10,000 per bus(1).

The use of ultra-low sulfur diesel fuel (required since 2006) allows these components to be added without the sulfur in diesel fuel contaminating the retrofitted equipment with a consequential loss in efficiency or damage. Ultra-low sulfur diesel fuel (maximum of 15 ppm sulfur content) is by itself expected to reduce particulate emissions by 5% to 9% (1).

Natural gas fueled school buses, if done correctly, can reduce particulate emissions by 70% to 90% at an additional cost of approximately $30,000 per bus(1). Replacement engines could reduce particulate emissions by 95% (2) as well as substantially reducing HC and NOx emissions.

Hydrocarbon and Carbon Monoxide Emissions

For ozone precursors, oxidation catalytic converters can reduce HC emissions by up to 50%. Carbon monoxide emissions may be reduced by up to 40%(2). Particulate traps will give some benefit, but are principally designed to lower particulate emissions.

The use of biodiesel fuel does reduce HC emissions, though its use will tend to increase NOx emissions (B20 up to 2%, B100 up to 10%(1)). Depending on the technology used, natural gas fueled school buses substantially lower NMHC. The U.S. EPA estimates NMHC emissions are reduced by 60%(1). NOx emissions, especially if lean-burn natural gas engines are used, may be lowered by a comparable amount. New technology replacement engines, built under the newest emissions certification standards would have substantial HC+NOx emission reductions.

The U.S. EPA has a technology Options Chart that they developed for their Clean School Bus USA Program. It lists the various technology options, their costs, and their benefits. It can be accessed at: http://www.epa.gov/cleanschoolbus/technology.htm.

Sources:
U.S. EPA Clean School Bus USA
Illinois Clean School Bus Program

Funding
There are various sources of funding for school bus retrofit programs. The U.S. EPA has annually funded retrofit programs. In 2007 they received seven million dollars under continuing resolution (H.J.R. 20) to fund projects nationwide. Eligible applicants that may apply for these funds include: state and local government, federally recognized Indian tribes, and non-profit organizations. Other sources of funding and grants include federal Congestion Mitigation and Air Quality (CMAQ) Program funds.

II: Description of how to implement
Local air planning agencies, state, or local government can implement these programs. Generally, they are funded through grants or other funding sources. They can be established relatively easily, with the needed outside infrastructure currently in place.

III. Feasibility of option
This is a very feasible option. School bus retrofit programs are operating throughout the United States.

IV. Background data and assumptions used
Emission reductions are generally those published by the U.S. EPA.

V. Any uncertainty associated with the option (Low, Medium, High)
Low. School Bus Retrofit Programs are proven strategies

VI. Level of agreement within the workgroup for this mitigation option
Good general agreement.

VII. Cross-over issues to other source groups
There will be little cross-over issues with other groups.

Mitigation Option: Subsidy Program for Cleaner Residential Fuels

I. Description of the mitigation option

Many families and individuals are forced by circumstances (economic, lack of availability, insufficient fuel delivery infrastructure, etc.) to use less than desirable fuels for cooking and heating. Many of these fuels, such as wood burning, emit high levels of toxic, or harmful, emissions, and carbon monoxide, hydrocarbon and organic compounds that are ozone precursors.

An option to reduce emissions that contribute to increased VOC, PM, CO, and air toxics is to promote the use of less polluting home heating and cooking fuels, especially electricity, propane, and natural gas in place of wood, coal, and kerosene. If wood is to continue to be used for home heating, at least a high efficiency EPA Phase II certified stove should be used.

Subsidizing Increased Cost of Fuel

Subsidizing the use of propane, natural gas, or electricity may allow low-income families to utilize these fuels in place of wood burning or other fuel sources, such as coal. Subsidy could be pegged to the economic need of the family, much like other welfare programs.

Home Heating

Replacing a traditional, non-certified wood stove with an oil furnace will reduce particulate (PM) emissions by over 99%, from 18.5 g/hr to 0.07 g/hr. Replacement with a natural gas furnace would reduce PM emissions even further to 0.04 g/hr (2).

The use of oil or gas furnaces in place of wood stoves would also have a substantial effect on carbon monoxide and emissions of hydrocarbons and other organic compounds, many of which have high ozone reactivities, as well as being fairly toxic gases. Encouraging the use of substituting electric or gas heat for cooking would similarly give a comparable emissions benefit.

New York State Environmental Protection Bureau estimates that a typical high efficiency (90%) gas or oil forced hot air furnace costs approximately $2690. This compares to a new EPA certified, catalytic equipped wood stove at approximately $2425, with a 72% efficiency rating (2).

Cleaner Wood Stoves

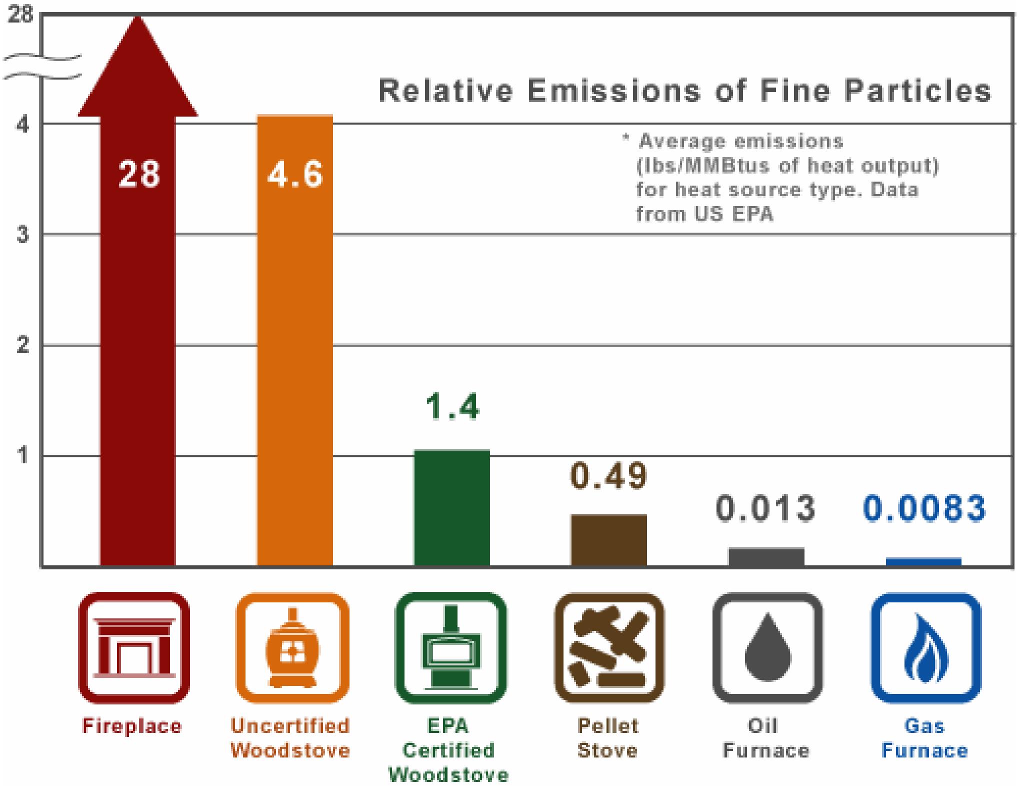
If a woodstove were used, it should be a new EPA certified one that would be expected to reduce fine particulate emission by 70% compared to an older non-controlled stove. Polycyclic aromatic hydrocarbons would be expected to go down from 0.36g/hr to 0.14 - 0.15 g/hr for EPA Phase I certified stoves to less than that for EPA Phase II certified stoves (2).

Nationwide, wood burning accounts for nine percent of home heating needs. However, it accounts for 45% of all particulate emissions from home heating (2). U.S. EPA Phase II standards are 7.5 g/hr PM for non-catalytic equipped stoves, and 4.1 g/hr PM for catalytic equipped ones (1,2). These standards are designed to reduce woodstove emissions by 60% to 80%(1).

In replacing an older uncontrolled stove with a new EPA certified stove, it is important to use an outside source of air for the heater box for combustion proposes. This prevents the stove from depleting a room's oxygen content, as well as preventing emissions from entering the house. Stoves should also have catalytic converters to ensure the lowest emissions. Common models currently may produce from 35,000 to 100,000 BTU, and are able to heat rooms from 400 to 2000, or more, square feet(3). US EPA has a website at: http://www.epa.gov/woodstoves, where more information may be obtained.

Chart One
Relative Emissions of Fine Particulates
(Grams per Hour)

U.S. EPA Chart



Source: U.S. EPA

Reference Sources:
(1). U.S. EPA
(2). New York State Environmental Protection Bureau
(3). Chimney Sweep, Inc.

II: Description of how to implement

This program may be organized much like Low Income Energy Assistance programs. A means test or other criteria could be established to prioritize available funding.

Funding this program, or set of programs, may include tax incentives, or other methods, such as voluntary grants from the natural gas extraction industry, mineral surtaxes, or drilling and permit fees. Enforcement penalties could also be used.

III. Feasibility of option

The program is very feasible. It would not only reduce emissions that could aggravate ambient ozone, PM, and CO, but would reduce toxic exposure to inhabitants of the house and nearby homes.

IV. Background data and assumptions used
It is assumed that there is a sufficient population that would benefit from an assistance program.

V. Any uncertainty associated with the option (Low, Medium, High)
Medium. Such a program, unless funded voluntarily as a public outreach program by industry, may require additional statutory authority, requiring legislative action, as well as well as regulatory development and adoption.

VI. Level of agreement within the workgroup for this mitigation option
Good general agreement. The option was agreed upon by the workgroup without dissent.

VII. Cross-over issues to other source groups
There are no cross-over issues identified at the present time.

Mitigation Option: Stage One Vapor Recovery

I. Description of the mitigation option:

Mandatory use of stage-one vapor recover systems will reduce evaporative emissions from service stations.

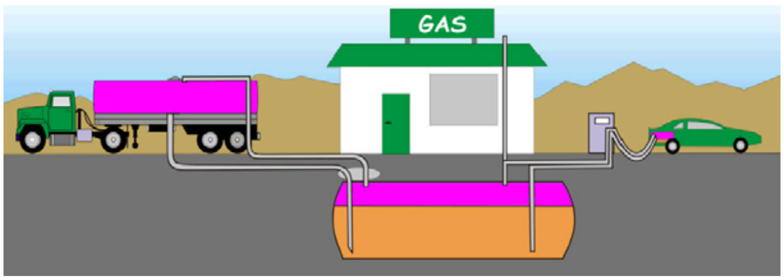
Refueling of underground service station tanks is a major source of evaporative hydrocarbon emissions. VOCs are released as the underground storage tank is refilled, when gasoline vapors in the tank's headspace are displaced. Sources estimate that 10-15 liquid gallons of gasoline are released from vapors displaced from the headspaces of various tanks, each time a gasoline transport truck fully unloads its products (1,2,3). Unless captured through a vapor recovery system, such as Stage I, these emissions will be released directly into the atmosphere.

In many areas, Stage I vapor recovery systems are required to control VOC emissions within the gasoline distribution system, from the refinery to the retail gasoline station. In the Denver metropolitan area, for instance, Stage I is required to control VOC releases that contribute to summertime ozone formation. Fire codes require the use of Stage I at service stations in other areas. But in many places their use is not required, and stations may, or may not, be using any vapor recovery stations, even if they are equipped with them. Stations that are equipped with Stage I vapor recovery systems may not be operating them. Other older stations may not even be equipped with vapor recovery systems.

The following diagram shows how Stage I works. In this diagram the fuel delivery truck unloads its product into the bottom of an underground storage tank through the refueling pipe. A second pipe then draws the vapors being displaced as the underground storage tank is being filling, and discharges them into the now emptying fuel delivery trucks compartment. The empty truck then returns to the refinery or terminal and releases the captured vapors into the refinery's or terminal's vapor recovery system, where they are condensed back into liquid gasoline and reused.

The same illustration also shows how Stage II vapor recovery systems work, by using the same principle, capturing the VOCs produced as an automobile is refueled. As the automobile is refueled, vapors displaced by the car's gasoline tank are drawn back through the dispensing pump back into the underground storage tank by a second refueling tube. There, they either condense into gasoline within the tank, or are directed into the refueling tanker truck, through the station's Stage I system when the underground tank is next refueled by the tank truck.

Stage I Vapor Recovery



Source: Calif. EPA, Nov.18, 2004

References:

"What You Should Know About Vapor Recovery", Michigan Department of Environmental Quality.
"Keeping It Clean: Making Safe and Spill-Free Motor Fuel Deliveries," Petroleum Equipment Institute, December 1992.
"New Hampshire Stage I/II Vapor Recovery Program", New Hampshire Department of Environmental Services.

Air Quality Benefits of Stage One Vapor Recovery

As part of its effort to reduce summertime ozone, the Denver metropolitan area requires the use of Stage 1 at all service stations. It is estimated that because of Stage I requirements, that perhaps 13.2 million pounds of VOCs (18.1 tons per day) are prevented from being emitted into the air*. Air toxics are also reduced.

Stage I vapor recovery systems are efficient. Up to 95%(1) of underground storage-tank refueling vapors are captured. Stage I is also cost effective. Vapors from the underground storage tanks are collected in the now empty tanker truck's compartments and taken back to the refinery or terminal, where they are condensed and reused. At $3.00 a gallon for gasoline seen in the summer of 2007, this equates to $2.1 million dollars worth of gasoline saved annually.

(1), Hensel, John, and Mike Mondloch,"Stage One Vapor Control In Minnesota", Minnesota Pollution Control Agency.

* Based on emission factors from the state of New Hampshire (11 lbs. VOC produced per 1000 gallons of gasoline vapors displaced), and 1.2 billon gallons of gasoline delivered to service stations in the Denver metropolitan area each year.

Cost

Many stations, while not operating their Stage I equipment are equipped with it. Others would have to be retrofitted. The Minnesota Pollution Control Agency estimates that retrofitting a station will cost up to $15,000 per station, with a more typical cost of approximately $10,000 per station. This is a very reasonable cost for the emissions benefits that can be derived.

II: Description of how to implement:
Implementation of Stage I vapor recovery would be through State Implementation Plans. A state could also adopt such as a program as a state-only program if not part of a SIP. The state would enforce the requirements.

III. Feasibility of option:
This option is fairly easy to develop and implement.

IV. Background data and assumptions used
A major assumption is that the four corners area will become nonattainment for summertime ozone, either as a result of elevated measurements, or the implementation of a new, lower, more rigorous ozone standard.

V. Any uncertainty associated with the option (Low, Medium, High):
Low.

VI. Level of agreement within the workgroup for this mitigation option:
Good general agreement.

VII. Cross-over issues to other source groups:
There does not seem to be much cross over.

Mitigation Option: Stage Two Vapor Recovery and Vehicle On-board Refueling Vapor Recovery Systems

I. Description of the mitigation option:
Mandatory use of Stage-II vapor-recover systems as well as programs designed to maintain vehicle's on-board refueling vapor recovery systems reduce evaporative emissions created during automobile refueling.

Automotive refueling is a major source of evaporative hydrocarbon emissions. As a vehicle's gas tank is filled gasoline vapors in the tank's headspace are displaced. It is estimated that when filling an empty 18-gallon fuel tank, 0.06 pounds of VOCs can be released (1,2), if such vapors are not captured by either a service station's Stage II vapor-recovery system, or for newer vehicles, the vehicle's on-board refueling vapor recovery system (this assumes that 30% of the vehicle's gasoline tank's headspace is composed of gasoline vapors and 70% by air) (2).

In a Stage II system, as an automobile is refueled, vapors displaced in the car's gasoline tank are drawn back through the dispensing pump back into the underground storage tank by a second refueling tube. There, they either condense into gasoline within the tank, or are directed into the refueling tanker truck, through the station's Stage I system when the underground tank is next refueled by the tank truck. The following illustration diagrams this.

Stage II Vapor Recovery System

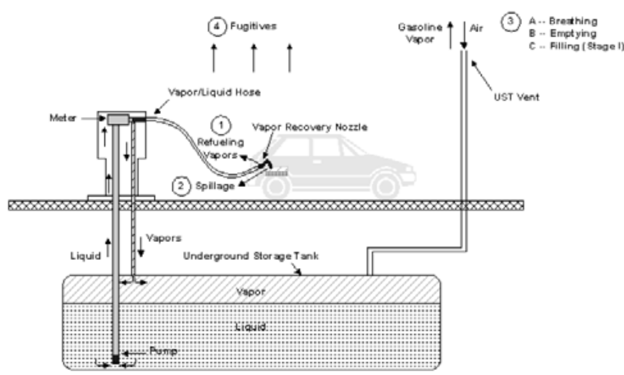
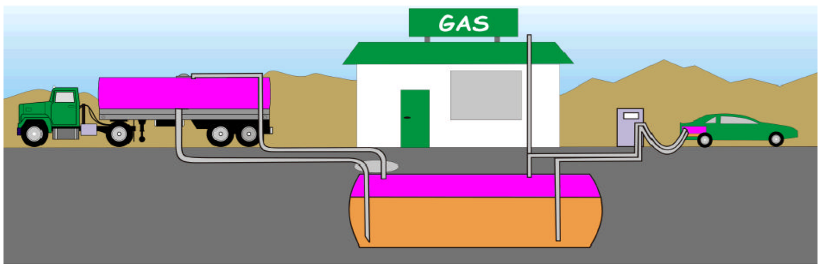


Figure 2. Controlled Stage II Process Operations with vapor recovery system.

Source: "Stage II Vapor Recovery Issue Paper", U.S. EPA, August 12, 2004.
http://www.ct.gov/dep/lib/dep/air/stageII/stage2issuepaper.pdf

Another illustration also shows how Stage II works in conjunction with Stage I. Vapors from the automobile's gasoline tank are routed back into the headspace of the station's underground storage tank. In this diagram the fuel delivery truck unloads its product into the bottom of an underground storage tank through the refueling pipe. A second pipe then draws the vapors being displaced as the underground storage tank is being filling, and discharges them into the now emptying fuel delivery trucks compartment. The empty truck then returns to the refinery or terminal and releases the captured vapors into the refinery's or terminal's vapor recovery system, where they are condensed back into liquid gasoline and reused.

Stage I & II Vapor Recovery Systems



Source: Calif. EPA, Nov. 18, 2004

References:
"New Hampshire Stage I/II Vapor Recovery Program", New Hampshire Department of Environmental Services.
"Stage II Vapor Recovery Issue Paper", U.S. EPA, August 12, 2004.

Air Quality Benefits of Stage II Vapor Recovery Systems
As part of its effort to reduce summertime ozone, many metropolitan areas across the nation with ozone concerns have adopted the use of Stage II vapor recovery systems at service stations. Stage II vapor recovery systems can be efficient. Depending on the frequency of inspection and equipment maintenance, up to 95%(1) of refueling vapors may be captured. In reducing VOCs, many air toxics, such as benzene and 1,3 butadiene are also reduced.

Modeling conducted by Mobiles Sources Program, Air Pollution Control Division, of the Colorado Department of Public Health and Environment, indicate that implementation of a Stage II vapor recovery program in the Denver Metropolitan area would reduce overall mobile source VOCs by 5.5% in the year 2007, and by 3.8% in the year 2012, when more vehicles are equipped with on-board vapor recovery systems.

On-board Refueling Vapor Recovery (ORVR) systems
On-board refueling vapor recovery (ORVR) systems work by routing escaping vapors from the fuel tank; through a charcoal canister that absorbs VOCs. The trapped VOCs are then pulled from the canister into the engine where they are burnt. ORVR systems have become standard equipment on light-duty automobiles beginning in 1998, and light duty trucks (trucks 1-2 starting in 2001, and trucks 3-4 in 2004).

As stated before, as the fleet penetration of on-board refueling vapor recovery systems increases, the emissions benefit from Stage II decreases somewhat. Currently, in the Denver metropolitan area, 54% of all gasoline motor vehicles now are equipped with on-board vapor recovery systems. As more of the fleet is equipped with on-board refueling vapor recovery systems, the effectiveness of Stage II is reduced. However, working together, they will both reduce refueling losses in the near to medium term, as shown in CDPHE's MOBILE6 modeling results. It should be pointed out that as ORVR systems deteriorate, refueling losses increase. At some point in the future, it may be necessary to implement some sort of inspection program to find and have fixed broken ORVR systems, maintaining the air quality benefits of these systems.

The U.S. EPA in their report "Stage II Vapor Recovery Issue Paper (August 12, 2004) includes a diagram (Figure 5, page 16 - shown below), of the refueling emissions trends for a hypothetical State. From inputs contributed by the American Petroleum Institute, this illustration shows four different scenarios; Stage II vapor recovery controls only (the blue line); on-board refueling vapor recovery only (the red line); Stage II vapor recovery controls with on-board refueling vapor recovery, where the ORVR interferes with the Stage II controls (the green line); and 4) Stage II vapor recovery controls and on-board refueling vapor recovery, where the ORVR does not interfere with the Stage II controls (the black line). The chart diagrams the years from 2005 through 2035 (1).

As seen in this diagram, a state with an existing Stage II vapor recovery program with an 85% effectiveness (blue line) will have a fraction of the refueling VOC emissions as a state that does not (the red line) in the year 2005. As more vehicles are equipped with ORVR systems, this advantage decreases, with at some point before 2015, the benefits of both control measures being equal. The blue line increases over time because of the increase in vehicle miles travels and does not include the effect of ORVR. However, before this time (2015), Stage II vapor recovery programs will give large benefits.

The other two scenarios shown represent decreasing VOCs over time with both control measures. There has been some research showing that Stage II can potentially interfere with on-board refueling vapor recovery systems. This is represented by the green line, where there is some increase in emissions as a result. However, all new Stage II systems certified by the state of California must show no interference with the ORVR. Using these approved systems, total VOCs are reduced for both Stage II and ORVR (the black line), where until 2025 there is a noticeable improvement having both systems.

Refueling Emissions Trends for Four Scenerios:

1) Stage II controls only (Blue Line), 2) On-board Refueling Vapor Recovery (ORVR) only (Red Line), 3) Stage II & ORVR with compatibility issues (Green Line), 4) Stage II & ORVR with no compatibility issues (Black Line)

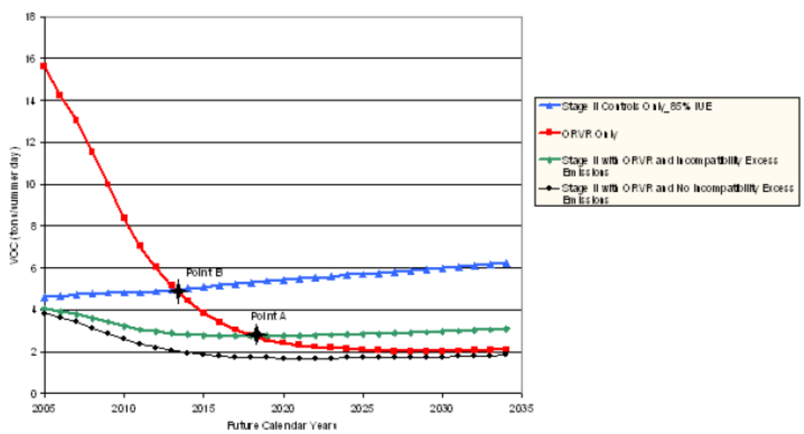


Figure 5. General emissions trends expected for refueling emissions in future calendar years for a hypothetical State (based on API studies).

Source: "Stage II Vapor Recovery Issue Paper", U.S. EPA, August 12, 2004.
http://www.ct.gov/dep/lib/dep/air/stageII/stage2issuepaper.pdf

(1) "Stage II Vapor Recovery Issue Paper", U.S. EPA, August 12, 2004.

Cost

There are costs to retrofit service stations with the necessary plumbing and equipment. In some cases this will be a major renovation to the station. Additionally, there will be on-going costs associated with operating and maintaining the Stage II vapor recovery system and equipment.

The state of New Hampshire, which has an operational Stage II vapor recovery program, estimates that the cost of Stage II installation at between $18,000 and $30,000 per station, depending on the station (1). They estimate on-going annual maintenance costs to be $1000 to $4000 per station yearly (1). Stage II requirements affect any station in that state that sells or has throughput of more than 420,000 gallons of gasoline annually (1).

(1) Environmental Fact Sheet, "New Hampshire's Gasoline Vapor Recovery Program - Protecting the Air We Breathe" New Hampshire Department of Environmental Services, 2004.

II: Description of how to implement:

Implementation of Stage II vapor recovery would be through State Implementation Plans. The state would enforce the requirements.

III. Feasibility of option:

This option is moderately hard to develop and implement. Gasoline service stations that are already plumbed for Stage II, and do not have to tear up concrete to put in vapor recovery plumbing are relatively easy to upgrade. Stations that need extensive work to install will be more difficult. Industry will not be supportive of this option.

IV. Background data and assumptions used

A major assumption is that the four corners area will become nonattainment for summertime ozone, either as a result of elevated measurements, or the implementation of a new, lower, more rigorous ozone standard.

V. Any uncertainty associated with the option (Low, Medium, High):

Low.

VI. Level of agreement within the workgroup for this mitigation option:

Good general agreement.

VII. Cross-over issues to other source groups:

There does not seem to be much cross over.

OTHER SOURCES: PUBLIC COMMENTS

Other Sources Public Comments

Comment	Mitigation Option
Dear Task Force Representative: I work for the Ute Mountain Tribe's Environmental Programs Department. We are about to partner with the EPA and the USGS to monitor radionuclides in the air and water around White Mesa, Utah where there is the only operating uranium mill in the nation. They are increasing production dramatically at the mill. We have significant concerns about radioactive dust blowing around out there. Any assistance that you or your staff could provide, funding if possible, would be a great thing. In the end we will have a publicly available, peer-reviewed report published by USGS and EPA. This could be a very important piece of the 4 corners air quality puzzle for you. My contact information is: Scott Clow, Water Quality Specialist, Ute Mountain Ute Tribe, PO Box 448, Towaoc, CO 81334, (970) 564-5431, scute@fone.net Thanks for considering this. Sincerely, Scott	
The last mitigation option makes me think that it is time to start considering regulating wood and coal burning stoves all-together. We have a tendency in the 4 corners to believe that we are small-fry, but continued urbanization is delivering us many big-city problems. In all, oil, gas and power plants tend to overshadow the cumulative impacts of residential activities. Our county governments should consider mitigation options accordingly.	
It is not enough to address the larger sources of air pollution in the Four Corners area. The efforts of this task force must also address the cumulative effects of the smaller sources.	
This is a great option. The Farmington/Aztec/Bloomfield area is an urban corridor, and the Durango/Bayfield area is quickly becoming so as well. We could easily reduce emissions and highway miles traveled if we were to expand upon park-and-ride systems (I believe I saw an ad for one between Ignacio and Durango) and also municipal transit.	Public Buy-in through Local Organizations to push for transportation alternatives and ordinances
Public outreach is great (often people are unaware of the health problems due to burning), but it may not reach the few and highly resistant people who burn regularly (both commercial and residential). As a resident, I would like to be able to call the sheriff and have enforcement that is effective (a fine, for example).	Develop Public Education and Outreach Campaign for Open Burning
The worst offending vehicles pass because their owners know how to beat the system on testing. Just enforce laws about taking cars off the road that visually are not in compliance. Add a tax based on engine size or exempt smaller engines and low weight vehicles.	Automobile Emissions Inspection Program
IM Programs will only work if all areas in that region are included. If they are not then owners of car will find ways to get around the program. Most of the owners that would do this are the owners of the cars that are the problem. Another way to make sure that your program is effective is to make sure that there is a assistance program for owners that can not afford to get their car emissions fixed.	Automobile Emissions Inspection Program

Comment	Mitigation Option
The IM programs will only be effective for our purposes if they are implemented in all areas. Also, the emissions programs for cars need stricter standards, thus making it economically infeasible to own larger engine, less efficient vehicles. There will always be those who find their way around the laws. However, if those laws are stricter, actually enforced, and applied throughout the Four Corners area then more problem vehicles will be taken off the road.	Automobile Emissions Inspection Program
On a voluntary basis, people could "adopt/subsidize" other vehicles that are not meeting emissions specs. Maybe this adoption could be tax deductible or a tax credit. How do we address the high emitting, newer vehicles (ie large trucks/cars)from the LEV (low emission vehicles)? Maybe a taxing structure would help both reduce the demand for new higher polluting vehicles, and help get high polluting older (the old "beater") vehicles off the road by helping to pay for their improvement/replacement.	Automobile Emissions Inspection Program
I would like City (and County if possible) ordinances to restrict idling. A rule that everyone follows will make it easier to get everyone on board the "no idling" plan. Public outreach also has to follow to teach people why idling causes problems and how "no idling" make make a difference. Signage at parking areas/unloading areas boat ramps, water filling stations/hydrants, the post office, grocery stores and other parking lots and etc. can remind drivers to turn off their engines.	Idle Ordinances
School bus retrofit--Let's do it! Then add public outreach to encourage more students to ride the bus, and we reduce emissions because the parents are not lined up in their cars to pick up/drop off their kids at school.	School Bus Retrofit
Though indirectly related to this topic, homes need to be upgraded weatherized and insulated so that we decrease the amount of fuel needed. Public outreach might help teach people how to build a clean fire. And people are burning trash in their wood stoves (similar to open burning). Coal is often used for heating and is particularly high in emissions, and seems to be equal to open burning.	Subsidy Program for Cleaner Residential Fuels

Energy Efficiency, Renewable Energy and Conservation

Energy Efficiency, Renewable Energy and Conservation: Preface

The Task Force identified a need for an Energy Efficiency, Renewable Energy, and Conservation (EEREC) mitigation option section for the Task Force report. Since this category had cross over among the groups, each group contributed to this section of the report. The Other Sources and Power Plants Work Groups met together at the November 8, 2006 Task Force meeting and briefly at the February 8, 2007 meeting to discuss EEREC as a topic. Louise Martinez, Bureau Chief of Energy Efficiency Programs with the New Mexico Energy, Minerals, and Natural Resources Department, gave a presentation on New Mexico Clean Energy Programs in the work group breakout session. New Mexico has a comprehensive set of renewable energy incentives to attract new projects and developers. The Four Corners area has a very strong solar energy resource and potential for energy efficiency improvements which both could offer environmental and health benefits.

Energy use is increasing in the Four Corners Area and in the U.S. as a whole. New generation will be required to meet additional energy demands. The work group on EEREC discussed that we could use the proactive NM position on clean energy as an example of a model to help write mitigation options for developing clean energy in the 4 Corners. Options focused on not only industry but also consumer behaviors. Three general areas were identified for options. Twenty-one mitigation options were brainstormed for the EEREC section; 18 were drafted.

Efficiency is important because efficiency is getting more out of each bit of energy we use. The result can be a direct benefit by reducing emissions from power plants or other sources and getting work done for less money. Efficiency has an indirect benefit by reducing the demand for additional energy production.

The work group brainstormed and drafted several options relating to efficiency. Options written included the following: Improved efficiency of home & industrial lighting; home audits for energy efficiency, as well as green building and energy efficiency incentives. An option was also written to improve county & city planning efforts. One option on power generation energy efficiency at existing power plants was written and included in the Existing Power Plants mitigation option section.

Renewable energy is important because it can benefit air quality by complementing and offsetting existing fossil fuel energy use and generation with clean energy sources. The work groups wrote options on better utilizing the solar resources in the Four Corners; expanding renewable portfolio standards to the Four Corners area municipalities and power cooperatives; creating/improving net-metering agreements with the electric utilities; and several others. A few policy options were written concerning importing and using only clean energy locally. One option tying together renewable energy and energy efficiency was written on “The Use and Credit of Energy Efficiency and Renewable Energy in the Environmental Permitting Process.” An option discussing the viability of biomass as an energy source to mitigate air pollution was also drafted in addition to an option for a bioenergy center.

Conservation, or using less energy, is also important because it reduces air pollution. Burning fossil fuels directly or using electricity generated by fossil fuel combustion results in increased air pollutants. Decreasing energy consumption correlates to decreased emissions. Options focusing on conservation centered around energy use. Options that could improve conservation efforts and reduce emissions included smart metering, direct load control, time based pricing, and residential bill structure changes. The work group discussed the need for more education of the public & industry on these issues. An option for an “Outreach Campaign for Conservation & Wise Use of Energy” was drafted. The San Juan VISTAS program, a voluntary emissions reduction program emphasizing energy efficiency, was discussed as a possible model for all sectors of industry and the community to work together to improve air quality through cost effective strategies in the Four Corners area.

ENERGY EFFICIENCY

Mitigation Option: Advanced Metering

I. Description of the mitigation option

Overview

Advanced Metering is the integration of electronic communication into metering technology to facilitate two-way communication between the utility and the customer equipment. Increasing electric energy prices and a growing awareness of the need to reduce the environmental impact of electric energy consumption are directing the industry, legislators and regulators to turn to Advanced Metering technologies for solutions. Strategic deployment of Advanced Metering Systems will facilitate or enable sustainable and cost-effective Energy Efficiency (EE) and Demand Response (DR) programs while at the same time providing a platform for cost-reducing innovations in the areas of customer service, reliability, operations and business practices.

Partly due to the time lag between when energy is consumed and when the consumption is billed, and partly because there is no tangible commodity to associate with their monthly electric bill, most end-use customers have a difficult time relating their monthly electric bill with their daily energy use patterns. Consequently, a critical component of effective and sustainable EE and DR programs is the ability to provide energy use information to customers in an understandable, timely and useable manner. An Advanced Metering System with its two-way communication system provides an infrastructure for sending and receiving timely energy use and pricing information and, if desired, load control signals directly to customers and end-use equipment.

Advanced Metering Systems supports both EE and DR programs. The primary objective of EE programs is to reduce the total amount of energy used annually by consumers. (DR focuses on shifting energy use to off peak hours and does not necessarily result in energy conservation). EE programs, therefore, are typically focused on consumer education, the use of more energy efficient equipment and other measures such as building improvements to reduce energy losses and waste.

Environmental Benefits - Advanced metering provides indirect benefit to the environment by providing real-time tools to enable the customer to make informed decisions around energy use and conservation. Energy conservation displaces a portion of electric generation and can lead to lower emissions of carbon dioxide (CO_2), nitrogen oxides (NO_x), sulfur dioxide (SO_2, and particulate matter (PM-10). In addition, reduced operation of generating plants means less water use and a reduction in the amount of natural resources (fossil fuels) being extracted from the earth. It can also help prevent or delay the need for building new power plants or other new energy infrastructure.

Economic- Direct operational benefits may result, including reduced monthly metering read costs; reduced meter read to billing time; reduced costs related to unaccounted for energy, energy diversion and energy theft; and reduced time to restore service following an outage.

Other benefits may include:

Increased customer satisfaction due to real time access to energy use information and other meter data by customer service personnel

Increased customer satisfaction due to the availability of accurate real time outage information and reduced outage times

The ability to apply innovative rate structures

Trade-offs - Capital costs to install Advanced Metering Systems can be more costly than conventional meters. Several years may be required for payback of Advanced Metering Systems.

II. Description of how to implement

Mandatory or Voluntary: Could be either voluntary or mandatory. Utilities have demonstrated that voluntary dynamic pricing programs can generate demand response and energy conservation. However, these programs tend to attract only modest levels of participation, in large part because they are narrowly targeted and passively marketed.

The public utility commission is the most appropriate entity to implement.

A differing opinion comment was received on this option during the Task Force Report Public Comment Period: "Advanced metering for home owners will not work. It will only enrich the electric companies who will use the data to set rates higher when people need the energy. An alternative is rolling blackouts on house ACs like that used in the Houston, TX area." See the public comments received for EEREC in the appendix to this section.

III. Feasibility of the option

A. Technical: Good feasibility. Programs have been applied and demonstrated at utilities across the country. Advanced metering systems are commercially available.

B. Environmental: Medium feasibility. Prices and advanced metering systems can be used to modify customer behavior to use less electricity within individual homes and businesses during peak hours, but metering by itself does not save energy. Instead, metering should be viewed as a technology that enables optimized performance and energy efficiency, and provides the information necessary for customers to make more-informed decisions regarding their energy use.

Should energy conservation take place, air emissions, water and fossil fuel use can be reduced through generation displacement. Additionally, EE and DR programs may allow utilities to hold off adding new generation assets, thereby, improving opportunities for employment of more advanced, demonstrated and cost-effective clean coal and renewable energy technology.

C. Economics: Advanced metering systems must be designed, managed, and maintained to cost-effectively meet site specific needs. Applications analysis must consider both initial costs (i.e. purchase and installation) and on-going operations costs (e.g., data analysis, system maintenance, and resulting corrective actions).

IV. Background data and assumptions used

Gillingham, K., R. Newell, and K. Palmer, The Effectiveness and Cost of Energy Efficiency Programs, Resources Publication, Fall 2004, pgs. 22-25, www.rff.org/Documents

Federal Energy Regulatory Commission, Assessment of Demand Response and Advanced Metering, Staff Report, Dockett No. AD-06-2-000

Assumption: Regulatory rate structures that allow for decoupling profits from sales to remove disincentives to conservation.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium. Voluntary programs do not guarantee energy conservation and emissions reductions.

VI. Level of agreement within the work group for this mitigation option

Good. This option write-up stems from a discussion at the February 7, 2007 meeting of the Power Plant Working Group.

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

Other Sources Group- Renewable Energy, Energy Efficiency and Conservation Mitigation Options

Mitigation Option: Cogeneration/Combined Heat and Power

I. Description of the mitigation option

Combined Heat and Power (CHP) is the sequential or simultaneous generation of multiple forms of useful energy (usually mechanical and thermal) in a single, integrated system. CHP systems consist of a number of individual components – prime mover (heat engine), generator, heat recovery, and electrical interconnection – configured into an integrated whole. The type of equipment that drives the overall system (i.e., the prime mover) typically identifies the CHP system. Prime movers presented the CHP systems discussed herein include reciprocating engines, combustion or gas turbines, steam turbines, and microturbines.

These prime movers are capable of burning a variety of fuels, including natural gas, coal, oil, and alternative fuels to produce shaft power or mechanical energy. Although mechanical energy from the prime mover is most often used to drive a generator to produce electricity, it can also be used to drive rotating equipment such as compressors, pumps, and fans. Thermal energy from the system can be used in direct process applications or indirectly to produce steam, hot water, hot air for drying, or chilled water for process cooling. When considering both thermal and electrical processes together, CHP typically requires only ¾ the primary energy separate heat and power systems require. This reduced primary fuel consumption is key to the environmental benefits of CHP, since burning the same fuel more efficiently means fewer emissions for the same level of output.

II. Description of how to implement

A. Mandatory or voluntary: The implementation of CHP should be "voluntary" since the economics, operational aspects and emissions must be customized to the design objectives of the facility.
B. Indicate the most appropriate agency(ies) to implement**:** Since the option is voluntary and based upon the business decision of the entity proposing the facility, there is agency that would be in a position to mandate requiring CHP to be used. However, there could be a number of state agencies involved in permitting a CHP facility, including the state Air Quality Division, to issue air quality related construction and operating permits as appropriate.

III. Feasibility of the option

A. CHP Technologies

1. Gas turbines: are typically available in sizes ranging from 500 kW to 250 MW and can operate on a variety of fuels such as natural gas. Most gas turbines typically operate on gaseous fuel with liquid fuel as a back up. Gas turbines can be used in a variety of configurations including (1) simple cycle operation with a single gas turbine producing power only, (2) combined heat and power (CHP) operation with a single gas turbine coupled and a heat recovery exchanger and (3) combined cycle operation in which high pressure steam is generated from recovered exhaust heat and used to produce additional power using a steam turbine. Some combined cycles systems extract steam at an intermediate pressure for use and are combined cycle CHP systems. Many industrial and institutional facilities have successfully used gas turbines in CHP mode to generate power and thermal energy on-site. Gas turbines are well suited for CHP because their high-temperature exhaust can be used to generate process steam. Much of the gas turbine-based CHP capacity currently existing in the United States consists of large combined-cycle CHP systems that maximize power production for sale to the grid.

2. Microturbines, which are small electricity generators that can burn a wide variety of fuels including natural gas, sour gases (high sulfur, low Btu content), and liquid fuels such as gasoline, kerosene, and diesel fuel/distillate heating oil. Microturbines use the fuel to create high-speed rotation that turns an electrical generator to produce electricity. In CHP operation, a heat exchanger referred to as the exhaust gas heat exchanger, transfers thermal energy from the

microturbine exhaust to a hot water system. Exhaust heat can be used for a number of different applications including potable water heating, absorption chillers and desiccant dehumidification equipment, space heating, process heating, and other building uses. Microturbines entered field-testing in 1997 and the first units began commercial service in 2000. Available and models under development typically range in sizes from 30 kW to 350 kW.

3. There are various types of reciprocating engines that can be used in CHP applications. Spark ignition (SI) and compression ignition (CI) are the most common types of reciprocating engines used in CHP-related projects. SI engines use spark plugs with a high-intensity spark of timed duration to ignite a compressed fuel-air mixture within the cylinder. SI engines are available in sizes up to 5 MW. Natural gas is the preferred fuel in electric generation and CHP applications of SI. Diesel engines, also called CI engines, are among the most efficient simple-cycle power generation options in the market. These engines operate on diesel fuel or heavy oil. Dual fuel engines, which are diesel compression ignition engines predominantly fueled by natural gas with a small amount of diesel pilot fuel, are also used. Higher speed diesel engines (1,200 rpm) are available up to 4 MW in size, while lower speed diesel engines (60 - 275 rpm) can be as large as 65 MW. Reciprocating engines start quickly, follow load well, have good part-load efficiencies, and generally have high reliabilities. In many instances, multiple reciprocating engine units can be used to enhance plant capacity and availability. Reciprocating engines are well suited for applications that require hot water or low-pressure steam.

4. Steam turbines that generate electricity from the heat (steam) produced in a boiler for CHP application. The energy produced in the boiler is transferred to the turbine through high-pressure steam that in turn powers the turbine and generator. This separation of functions enables steam turbines to operate with a variety of fuels including natural gas. The capacity of commercially available steam turbine typically ranges between 50 kW to over 250 MW. Although steam turbines are competitively priced compared to other prime movers, the costs of a complete boiler/steam turbine CHP system is relatively high on a per kW basis. This is because steam turbines are typically sized with low power to heat (P/H) ratios, and have high capital costs associated with the fuel and steam handling systems and the custom nature of most installations. Thus the ideal applications of steam turbine-based CHP systems include medium- and large-scale industrial or institutional facilities with high thermal loads and where solid or waste fuels are readily available for boiler use.

<u>B. Environmental:</u> CHP technologies offer significantly lower emissions rates per unit of energy generated compared to separate heat and power systems. The primary pollutants from gas turbines are oxides of nitrogen (NO_x), carbon monoxide (CO), and volatile organic compounds (VOCs) (unburned, non-methane hydrocarbons). Other pollutants such as oxides of sulfur (SO_x) and particulate matter (PM) are primarily dependent on the fuel used. Similarly emissions of carbon dioxide are also dependent on the fuel used. Many gas turbines burning gaseous fuels (mainly natural gas) feature lean premixed burners (also called dry low-NO_x burners) that produce NO_x emissions ranging between 0.3 lbs/MWh to 2.5 lbs/MWh with no post combustion emissions control. Typically commercially available gas turbines have CO emissions rates ranging between 0.4 lbs/MWh – 0.9 lbs/MWh. Selective catalytic reduction (SCR) or catalytic combustion can further help to reduce NO_x emissions by 80 percent to 90 percent from the gas turbine exhaust and carbon-monoxide oxidation catalysts can help to reduce CO by approximately 90 percent. Many gas turbines sited in locales with stringent emission regulations use SCR after-treatment to achieve extremely low NO_x emissions.

Microturbines have the potential for low emissions. All microturbines operating on gaseous fuels feature lean premixed (dry low NO_x, or DLN) combustor technology. The primary pollutants from microturbines include NO_x, CO, and unburned hydrocarbons. They also produce a negligible amount of SO_2.

Microturbines are designed to achieve low emissions at full load and emissions are often higher when operating at part load. Typical NO_x emissions for microturbine systems range between 0.5 lbs/MWh and 0.8 lbs/MWh. Additional NO_x emissions removal from catalytic combustion is microturbines is unlikely to be pursued in the near term because of the dry low NO_x technology and the low turbine inlet temperature. CO emissions rates for microturbines typically range between 0.3 lbs/MWh and 1.5 lbs/MWh.

Exhaust emissions are the primary environmental concern with reciprocating engines. The primary pollutants from reciprocating engines are NO_x, CO, and VOCs. Other pollutants such as SO_x and PM are primarily dependent on the fuel used. The sulfur content of the fuel determines emissions of sulfur compounds, primarily SO_2. NO_x emissions from reciprocating engines typically range between 1.5 lbs/MWh to 44 lbs/MWh without any exhaust treatment. Use of an oxidation catalyst or a three way conversion process (non-selective catalytic reductions) could help to lower the emissions of NO_x, CO and VOCs by 80 percent to 90 percent. Lean burn engines also achieve lower emissions rates than rich burn engines.

Emissions from steam turbines depend on the fuel used in the boiler or other steam sources, boiler furnace combustion section design, operation, and exhaust cleanup systems. Boiler emissions include NO_x, SO_x, PM, and CO. The emissions rates in steam turbine depend largely on the type of fuel used in the boiler. Typical boiler emissions rates for NO_x with any postcombustion treatment range between 0.2 lbs/MWh and 1.24 lbs/mmBtu for coal, 0.22 lbs/mmBtu to 0.49 lbs/mmBtu for wood, 0.15 lbs/mmBtu to 0.37 lbs/mmBtu for fuel oil, and 0.03lbs/mmBtu – 0.28 lbs/mmBtu for natural gas. Uncontrolled CO emissions rates range between 0.02 lbs/mmBtu to 0.7 lbs/mmBtu for coal, approximately 0.06 lbs/mmBtu for wood, 0.03 lbs/mmBtu for fuel oil and 0.08 lbs/mmBtu for natural gas. A variety of commercially available combustion and post-combustion NO_x reduction techniques exist with selective catalytic reductions achieving reductions as high as 90 percent. SO_2 emissions from steam turbine depend largely on the sulfur content of the fuel used in the combustion process. SO_2 composes about 95% of the emitted sulfur and the remaining 5 percent are emitted as sulfur tri-oxide (SO_3). Flue gas desulphurization (FGD) is the most commonly used post-combustion SO_2 removal technology and is applicable to a broad range of different uses. FGD can provide up to 95 percent SO_2 removal.

While not considered a pollutant in the ordinary sense of directly affecting health, CO_2 emissions do result from the use the fossil fuel based CHP technologies. The amount of CO2 emitted in any of the CHP technologies discussed above depends on the fuel carbon content and the system efficiency. The fuel carbon content of natural gas is 34 lbs carbon/mmBtu; oil is 48 lbs of carbon/mmBtu and ash-free coal is 66 lbs of carbon/mmBtu.

<u>C. Economic:</u> The total plant cost or installed cost for most CHP technologies consists of the total equipment cost plus installation labor and materials, engineering, project management, and financial carrying costs during the construction period. The cost of the basic technology package plus the costs for added systems needed for the particular application comprise the total equipment cost. Total installed costs for gas turbines, microturbines, reciprocating engines, and steam turbines are comparable. The total installed cost for typical gas turbines ranges from $785/kW to $1,780/kW while total installed costs for typical microturbines in grid-interconnected CHP applications may range anywhere from $1,339/kW to $2,516/kW. Commercially available natural gas spark-ignited engine gensets have total installed costs of $920/kW to $1,515/kW, and steam turbines have total installed costs ranging from $349/kW to $918/kW.

Non-fuel operation and maintenance (O&M) costs typically include routine inspections, scheduled overhauls, preventive maintenance, and operating labor. O&M costs are comparable for gas turbines, gas engine gensets, steam turbines and fuel cells, and only a fraction higher for microturbines. Total O&M costs range from $4.2/MWh to $9.6/MWh for typical gas turbines, from $9.3/MWh to $18.4/MWh for commercially available gas engine gensets and are typically less than $4/MWh for steam turbines. Based on manufacturers offer service contracts for specialized maintenance, the O&M costs for microturbines appear to be around $10/MWh.

IV. Background data and assumptions used

A. CHP offers energy and environmental benefits over electric-only and thermal-only systems in both central and distributed power generation applications. CHP systems have the potential for a wide range of applications and the higher efficiencies result in lower emissions than separate heat and power generation system. The advantages of CHP broadly include the following:

- The simultaneous production of useful thermal and electrical energy in CHP systems lead to increased fuel efficiency.
- CHP units can be strategically located at the point of energy use. Such onsite generation avoids the transmission and distribution losses associated with electricity purchased via the grid from central stations.
- CHP is versatile and can be coupled with existing and planned technologies for many different applications in the industrial, commercial, and residential sectors.

V. Any uncertainty associated with the option Medium

VI. Level of agreement within the work group for this mitigation option

Although a general discussion of this option has not occurred between the working group members, most of the members do not have technical experience working with CHP facilities.

Source of Information: Catalogue of CHP Technologies, U.S. Environmental Protection Agency, Combined Heat and Power Partnership

Mitigation Option: Green Building Incentives

I. Description of the mitigation option
This option involves the promotion of the Leadership in Energy Efficiency and Design certification LEED through state sponsored incentives. The LEED Green Building Rating System™ is the nationally accepted benchmark for the design, construction, and operation of high performance green buildings. LEED gives building owners and operators the tools they need to have an immediate and measurable impact on their buildings' performance. LEED promotes a whole-building approach to sustainability by recognizing performance in five key areas of human and environmental health: sustainable site development, water savings, energy efficiency, materials selection, and indoor environmental quality.

The cost of LEED certification depends upon: the level of certification sought, the particular project demographics and characteristics, the availability of grants for achieving certification, the LEED experience of the Design Team, the LEED experience of the estimator, the stage in the design at which the Client makes the decision to seek certification (the earlier the better), and the Client's perception of the value and benefits of a more attractive building environment for their occupants. While the factors above may seem numerous, they are quantifiable, they can be priced, and they can be managed.

Certain aspects are realized at no additional cost due to the high level construction performance that today's contractors insist upon as standard practice. Clearly, the higher the certification level, the more it is required to accept the points that have significant additional cost impact. The strategy therefore is to firstly seek the points that have no financial impact, followed by either the insignificant premium costs or the insignificant additional costs. The expensive points are usually only sought when applying for Gold or Platinum certification.

II. Description of how to implement
A. Mandatory or voluntary: Because of concerns associated with the additional costs of certification, this program should be voluntary in scope. Yet, it should be mandatory for all new government buildings to be modeled after some of the options and foundations that this program is built upon, without necessarily reaching for LEED certification.
B. Indicate the most appropriate agency(ies) to implement: Colorado/NM Offices of Energy Management and Conservations,

III. Feasibility of the option
A. Technical: There are only two buildings with the highest LEED certification nation wide, although this certification is technically feasible. There are thousands of buildings build or retrofitted throughout the nation that initially use the guidelines and practices laid out in the LEED certification although they are not LEED certified.
B. Environmental: The environmental benefits of energy efficiency programs are very well documented.
C. Economic: This certification does increase the cost of construction through additional project management and supply demands. Although there are additional costs, the LEED certification does show economic benefits over the life of the building.

IV. Background data and assumptions used

V. Any uncertainty associated with the option: Medium

VI. Level of agreement within the Work Group for this option: TBD

Mitigation Option: Improved Efficiency of Home and Industrial Lighting

I. Description of the Mitigation Option

Utilizing compact fluorescent lights can result in significant energy savings when compared to traditional incandescent lights. Improved lighting efficiency in homes and in commercial/industrial business applications throughout the Four Corners States has tremendous potential to reduce energy consumption, save money, and reduce the amount of fuel burned in coal fired power plants. Burning less coal would result in fewer air pollution emissions.

One quote commonly used in news articles states "If every home in the U.S. switched one light bulb with an ENERGY STAR, we would save enough energy to light more than 2.5 million homes for a year and prevent greenhouse gases equivalent to the emissions of nearly 800,000 cars" (U.S. EPA, 2006).

Background:
Artificial lighting accounts for approximately 15 percent of the energy use in the average American home (U.S. DOE, 2006). Lighting consumes about 20 percent of all electricity used in the U.S. The nationwide lighting figure is potentially as high as 21-34 percent when the air conditioning needed to offset the heat produced by conventional lighting is considered (Rocky Mountain Institute, 2006).

Benefits: Energy Star qualified compact fluorescent light bulbs (CFLs) have many benefits including:

CFLs use 70 to 75 percent less energy than standard light bulbs (General Electric Company, 2006) with minimal loss of function. If the cost of the bulbs, lower energy use, and longer operating life are considered, a consumer can save approximately $52 over eight years for each CFL bulb that replaces a standard light bulb (Rocky Mountain Institute, 2004).

More than 90 percent of the energy used by incandescent lights is given off as heat, which creates the need run air conditioners to compensate for the heat generation and increases energy use (Rocky Mountain Institute, 2006). CFLs generate 70 percent less heat, reducing the need to cool interior air (US EPA, 2006).

CFLs commonly have an operating life of 6,000-15,000 hours compared to 750-1,500 hours for the average incandescent light (USDOE, 2006). CFLs last from 6-15 times longer.

At 4 mg of mercury per light, CFLs have the lowest mercury content of all lights containing mercury. All fluorescent lights contain mercury, incandescent lights do not. Use of CFLs results in a net reduction in mercury because coal power is such a large source of atmospheric mercury. The 70 percent lower energy consumption from CFLs compared to incandescent lights, results in a 36 percent mercury reduction into the atmosphere by coal-burning power plants. With proper recycling, the mercury released by CFLs decreases up to 76 percent compared to incandescent lights (US EPA, 2002; Rocky Mountain Institute, 2004).

Reduction in coal produced energy consumption would also result in a decrease of SOx, NOx, CO2, and other air pollution emissions. It can be demonstrated that running a 100-watt light bulb 24 hours a day for one year requires about 714 pounds of coal burned in a coal power generator. CFLs that use 70 to 75 percent less energy, would also translate from less power used, less coal burned, and fewer emissions. "Every CFL can prevent more than 450 pounds of emissions from a power plant over its lifetime" (U.S. EPA, 2006)

II. Description of how to implement

It has been determined that lack of awareness about the environmental benefits and energy/cost savings of CFL lights is the single largest barrier to their widespread use. CFL light replacement and education programs already exist in the U.S. and in other countries. Components of these programs were used in preparing this mitigation option.

Options could include any or all of the following:

States adopt the goal of delivering one free CFL bulb to every household in Colorado, New Mexico, Arizona, and Utah. Utilities, businesses, communities, and volunteers work together to deliver bulbs and information on the cost savings and environmental benefit of using CFLs.
Within the Four Corners States, adopt a campaign which includes regional advertising, information brochures, and marketing to promote awareness about the energy efficiency and environmental benefits of switching to CFL lights.
Provide light retailers with point-of-sale displays illustrating CFL cost savings, energy savings, proper CFL bulb selection, environmental benefits etc.
Offer State tax incentives for businesses/corporations that build or retrofit facilities using advanced lighting technologies including CFLs.

Voluntary or mandatory – The responsibility to develop a CFL light distribution and education program should be headed by the State governments of the Four Corners region. Coal power plants, utility companies, and other energy-related industry could voluntarily contribute to the purchase of CFL lights for distribution in households, and also contribute to educational awareness programs.

B. Indicate the most appropriate agency(ies) to implement – Colorado Department of Public Health and the Environment, New Mexico Environment Department, Utah Division of Air Quality, Arizona Department of Environmental Quality, DOE and EPA should take lead program roles. Certain aspects, such as purchasing lights for distribution, could be cooperatively funded by the Four Corners region coal-burning power plants, or State governments.

III. Feasibility of the Option

Technical: CFL technology is well developed and commonly available. In fact, large manufacturers of CFLs such as the General Electric Company and large distributors such as Walmart have embarked on major campaigns to promote and distribute CFL lights primarily for the "green" energy savings they represent (Fishman, 2006).

Environmental: Proven 70 percent reduction in energy consumption compared to traditional incandescent lights. Energy efficiency translates to reduction in air pollution emissions from coal-fired power plants. Lowest mercury content of all fluorescent lights, lower overall mercury emissions due to less coal based energy consumed.

Economic: Proven cost savings to consumers due to high energy efficiency and longer bulb life. If a 75 watt bulb is replaced by an 18 watt CFL bulb which is operated four hours a day, the estimated eight year savings is $36 - $52 (U.S. EPA, 2006, Rocky Mountain Institute, 2004). This calculation accounts for the higher purchase cost of CFLs.

IV. Background Data and Assumptions Used

(1) Fishman, Charles, 2006. How Many Lightbulbs Does it Take to Change the World? One. And You're Looking at It. Fast Company Magazine, New York, NY. www.fastcompany.com/magazine/108/open_lightbulbs.html

(2) General Electric Company, 2006. Ecomagination – For the Home: Compact Fluorescent Lighting. http://ge.ecomagination.com

(3) U.S. DOE, 2006. Energy Efficiency and Renewable Energy Consumers Guide: Lighting. http://www.eere.energy.gov/consumer/your_home/lighting

(4) U.S. EPA, 2006. Compact Fluorescent Light Bulbs: ENERGY STAR. Http://www.energystar.gov/

(5) U.S. EPA, 2002. Fact Sheet: Mercury in Compact Fluorescent Lamps (CFLs). www.nema.org/lamprecycle/epafactsheet-cfl.pdf

(6) Rocky Mountain Institute, 2006. Efficient Commercial/Industrial Lighting. http://www.rmi.org/sitepages/pid297.php

(7) Rocky Mountain Institute, 2004. Home Energy Briefs, #2 Lighting. http://www.rmi.org/

V. Any Uncertainty Associated With the Option
Low – both for feasibility and energy savings and environmental benefit through emissions reductions.

VI. Level of Agreement within the Work Group for this Mitigation Option TBD.

VII. Cross-over Issues to the Other Source Groups None at this time.

Mitigation Option: Volunteer Home Audits for Energy Efficiency

I. Description of the mitigation option
This option involves the development and implementation of a program or project that will engage community members in providing free energy audits to area residents. These audits of low income areas will find the largest sources of energy loss in homes and businesses and will provide simple solutions to the problem. Many local programs exist as examples, but currently only one program exists. Farmington had "make a difference day" at college, where they went to 10 homes with weatherization checklist. This could serve as a launching step for the program.

The air quality benefits to the region will be generated by increasing the energy efficiency of the homes and businesses involved in the program, therefore decreasing the amount of energy needed to be created by local coal burning power plants. In addition, those involved in the program can find out other sources by which to reduce their energy consumption (e.g. car pooling, appliance efficiencies).

II. Description of how to implement
A. Mandatory or voluntary: The audit of a home should be made mandatory for any individual or family receiving energy assistance from state or local governments and/or utilities. For those not receiving assistance, the program is voluntary in scope.

Weatherization and insulation subsidization: PNM has a good neighbor program; grants could go to non-profits; rebates could be used.

B. Indicate the most appropriate agency(ies) to implement: Colorado/NM Offices of Energy Management and Conservations, Americorps or Vista programs

III. Feasibility of the option
A. Technical: Similar programs are prevalent nationwide, this option is technically feasible.
B. Environmental: The environmental benefits of energy efficiency programs are documented.
C. Economic: Most energy efficiency programs, especially implemented with volunteers, are economically viable and sustainable.

IV. Background data and assumptions used N/A.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the Work Group for this option All agreed.

VII. Cross-over issues to the other source groups None at this time.

Mitigation Option: The Use and Credit of Energy Efficiency and Renewable Energy in the Environmental Permitting Process

I. <u>Description of the mitigation option</u>

In principle, facilities implementing activities that lead to energy efficiency (EE) and rely upon renewable energy (RE) can receive additional incentives/ flexibility in their State air quality permits. A goal would be to provide alternatives to conventional energy sources that occur within the nexus of environmental, energy, and economic activities. Such an effort would also allow EE/RE to compete with traditional pollution control technologies to reduce emissions and encourage more environmentally-sensitive energy generation.

The benefits to industry might include: categorical permit exemptions for specific source categories that incorporate EE and/or RE if their use result in significant ambient air quality improvements; use of EE/RE to represent offsets for the purpose of major source NSR review; education and promotion of EE/RE for the purpose of avoiding a permit requirement (i.e., reducing emissions below de minimus regulatory thresholds or "syn minoring"); incorporating EE/RE as a control option in the Reasonable Available Control Technology (RACT) review process for minor sources located in non-attainment and attainment/maintenance areas, and; other benefits as identified. State air quality agencies could also provide benefits to industry by considering: "fast tracking" environmental permit requests of facilities incorporating EE/RE; recognizing participating facilities through various environmental leadership awards' programs; and, and other ideas as appropriate.

The benefits to the states could include: air quality improvements and help in avoiding future air quality problems; energy security; economic development (e.g., new jobs); environmental and energy leadership; facilitated collaboration between State and Federal agencies; and synergism of technical resources.

Such EE/RE approaches could be "codified" in State Implementation Plans, Supplemental Environmental Projects, and/or enforceable air pollution permits. EE/RE could also be tied to State Portfolio Standards (e.g., Colorado Renewable Energy Standards at 10% by year 2015) or other mechanisms.

II. <u>Description of how to implement</u>

A. <u>Mandatory or voluntary:</u> Voluntary for industry to enter into EE/RE agreements, though possibly enforceable through State permits or SIPs.

B. B. <u>Indicate the most appropriate agency(ies) to implement:</u> State Air Quality agencies or other authorities responsible for issuing air quality permits; State Offices' of Energy Management and Conservation (or like agencies); Department of Energy, if necessary in determining appropriate EE/RE initiatives;

<u>III. Feasibility of the option</u>

A. <u>Technical:</u> Technically, permitting agencies and interested industry would need to come up with a mutually satisfying definition of "EE/RE," including possibly setting minimum EE/RE requirements. For example, EE/RE efforts might include: establishing/ continuing "green" programs such purchasing wind power to generate a significant percentage of energy to operate office buildings and facilities; incorporating solar power; expanding the use of alternative vehicles as vehicles of first choice in industry fleets; using biodiesel fuel use in fleet vehicles; encouraging other industry partners to adopt green programs and assist them with expertise and experience (peer to peer mentoring); using industry and State resources, combined with other resources, to educate employees and general public to EE/RE measures; and, exploring grants and other funding mechanisms for EE/RE efforts. Also, it would make sense to start this on a pilot level scale to resolve any challenges that are identified in an initial effort.

B. Environmental: It's been demonstrated that there are direct environmental benefits from the use of EE and RE (e.g., reduced emissions of criteria and hazardous air pollutants, including SOx, NOx, mercury, etc.). Such EE/RE may also address concerns for impacts on regional haze and climate change.

C. Economic: EE/RE could be a significant financial gain for participating facilities in terms of: saved revenue from energy efficiency ("profits" could be re-directed to other aspects of the facility/industry); saved revenue by not having to transport fuels across the country, such as coal and heating oil; fuel price protection; reduced exposure to potential carbon taxation; an offset/trading value for early adopters and efficient reducers; public perception, and/or; others to be identified.

IV. Background data and assumptions used

Efforts would need to begin by establishing a workgroup with appropriate professionals who could illuminate opportunities to implement EE/RE through permitting and rule changes. Also, this initiative would need to work with permitting agencies' inventory groups to collect data to identify source categories that may be appropriate pilot project candidates for an EE/RE initiative.

V. Any uncertainty associated with the option (Low, Medium, High)

Medium, as there are not many examples to draw upon. Also, mutually satisfying definitions of EE/RE would need to be developed.

VI. Level of agreement within the work group for this mitigation option.

TBD but is assumed to be medium to high, depending on the workload necessary to get this effort underway.

VII. Cross-over issues to the other source groups TBD

RENEWABLE ENERGY

Mitigation Option: Expand the Renewable Portfolio Standards (RPS) to be Mandatory for Coops and Municipalities

I. Description of the mitigation option

The installation of new renewable generation has the potential to reduce the quantity of fuel combusted at existing fossil generation facilities thereby reducing air emissions and may potentially reduce the size of new generation that is needed to be built in the future.

Investor owned electric utility companies in New Mexico are required to provide 5% of the total energy supplied to its retail customers via renewable energy beginning in January of 2006. This requirement grows by 1% per year until 2011 when the requirement is l0%. This Renewable Portfolio Standard (RPS) requirement is part of the Rule 572 which was adopted by the NM Public Regulation Commission (NMPRC) in December of 2002. The New Mexico State legislature later passed the Renewable Energy Act, signed by the Governor on May 19, 2004, which codified this rule.

II. Description of how to implement

A. Mandatory or voluntary

The Renewable Energy Act states that the NMPRC may require that a rural electric cooperative 1) offer its retail customers a voluntary program for purchasing renewable energy under rates and terms that are approved by the NMPRC, but only to the extent that the cooperative's suppliers make renewable energy available under wholesale power contracts; and 2) report to the NMPRC the demand for renewable energy pursuant to a voluntary program. The Act is silent regarding municipalities at this time.

B. Indicate the most appropriate agency(ies) to implement

The NMPRC, the New Mexico Environment Dept, the New Mexico Energy, Minerals and Natural Resources Dept.

III. Feasibility of the option

A. Technical: Resource maps indicate that there is a good solar resource in the Four Corners area; however, wind energy, biomass, and geothermal are somewhat limited. Solar power generation is still more expensive than fossil-fired generation at this time.

B. Environmental: The environmental benefits of off-setting fossil-fired generation with renewable generation are well documented.

C. Economic: Each individual utility must balance it own unique needs to maintain a balance between reliability, environmental performance and cost. Integrating renewables into a utilities generation portfolio can cause electric prices to increase and adversely affect reliability to the utility's customers.

IV. Background data and assumptions used

Economic Outlook for Various Generation Technologies (2010)				
	Efficiency (%)	Capacity Factor (%)	Overnight Capital Cost(1) ($/kW)	Cost of Electricity (COE)(1) ($/MWh)
Wind (Class 3 to Class 6)(9)	N/A	30-42	1190	53-69

Solar Thermal (Parabolic Trough)	N/A	33	3410	180
Biomass CFB	28	85	2160	67
Coal(2) PC SC	39	80	1350	44
Coal(2) PC USC w/ CO2 capture	30	80	2270	72
Coal(2) CFB	36	80	1480	53
IGCC(2) GE – Quench W/O CO2 capture	37	80	1490	51
IGCC(2) GE – Quench w/ CO2 capture	30	80	1920	65
NGCC(4) (@ $4/MM Btu)	46	80(5)	500	43
NGCC(4) (@ $6/MM Btu)	46	80(5)	500	59
NGCC(4) (@ $8/MM Btu)	46	80(5)s	500	76

Acronyms: kW- kilowatts; MWh – megawatts/hour; CFB- circulating fluidized bed; PC- pulverized coal; SC-supercritical; USC- ultra-supercritical coal; IGCC- integrated gasification combined cycle; CFB- coal-fired boiler; NGCC- natural gas combined cycle

Notes:
All costs in 2006$; COE in levelized constant 2006$ and includes capital cost. Capital Cost is overnight, W/O Owner, AFUDC costs.
All fossil units about 600 MW capacity; Pittsburgh#8 coal for PC, CFB, IGCC.
Based on Gas Turbine technology limitations to handle hydrogen
NGCC unit based on GE 7F machine or equivalent by other vendors;
Represents technology capability
Value shown is 10% emission of total. The remainder is assumed to be absorbed by the biomass plant crop growth cycle
Includes reservoir development and associated cost for fuel supply
Reinjection of fluid in closed loop operation assumed
Wind COE values estimated via 2005 EPRI TAG analysis.

V. Any uncertainty associated with the option (Low, Medium, High)
High. Generally, the co-ops and municipalities do not like mandates.

VI. Level of agreement within the work group for this mitigation option
Mixed due to the fact that municipalities and rural electric cooperatives in the Four Corners area are relatively small and any participation in a statewide RPS will have a minimal impact on air quality.

VII. Cross-over issues to the other Task Force work groups None identified.

Mitigation Option: Four Corners States Adopt California Standards for Purchase of Clean Imported Energy

I. Description of the mitigation option

California has adopted a law that bans import of power from sources that generate more greenhouse gases than in-state natural gas plants. This law, which goes into effect January 1, 2007, impacts power generated in coal-fired plants in the Four Corners area, among others. Critics of this law say it will not accomplish its purpose of reducing emission of greenhouse gases, particularly carbon dioxide, because power from plants that do not meet CA's standards will simply be sold in other markets. If the Four Corners states (CO, NM, UT and AZ) adopted similar rules, pressure would be placed on the owners of many, if not all, the dirty plants in our area, plus a number of others, to clean up their emissions to meet the new standards. In so doing, a real contribution to the reduction of greenhouse gases, as well as other pollutants, would be made.

II. Description of how to implement

Four points relative to the CA legislation need to be addressed.

First, to be effective in a timely way, the rules need to apply to a utility's existing contracts that extend beyond a reasonable period of time, for example, five years. In anticipation of the January 1 implementation date for the CA law, some CA cities are renegotiating their long-term contracts, and extending them out to 2044. This must be avoided. Incentives will have to be provided to both sides in order to entice them to renegotiate their contracts

Second, some of the motivation for contract renegotiation relates to significant reductions in cost of power after the capital costs of the plant are retired. Incentives for renegotiation for similar reasons must be reduced or eliminated.

Third, state laws in the Four Corners area must specify power imported from 'other jurisdictions', such as from tribal nations as well as other states, in order to be effective in our area, since most present and future coal-fired power plants will be built on tribal lands, albeit within one of the Four Corners states. Additionally, tribal jurisdictions may wish to adopt similar legislation on the importation of power into their lands from external sources.

Fourth, the Four Corners states may not have a standard comparable to CA's standard, i.e., that of the greenhouse gas emissions of 'in-state natural gas plants'. In lieu of an appropriate in-state standard, a state could adopt CA's standard, or the average emission level for natural gas fired plants on a national level.

These requirements must be mandatory if they are to be effective

State and tribal permitting agencies should be given responsibility of implementation

III. Feasibility of the option

Technical - Four Corners states can seek technical assistance from the state of CA, which should be willing to assist in order to avoid dilution of the impact of their own law. Monitors of greenhouse gas emissions will need to be in place if not already in use

Environmental – This option would have a significant environmental impact

Economic – This option would also have a significant economic impact. There is no doubt that plants requiring significant pollution upgrades or even plant phase outs would raise the cost to shareholders and that these costs would be passed along to the customer. However, this is appropriate. End runs around the legislation, such as, marketing the power outside CA and the Four Corners area would occur to some extent. Obviously, addressing this issue at a national level would be far superior to a state-by-state approach; however, in lieu of national action, this option takes CA's step significant further.

Political – this option will be a very hard sell. Constituents in all Four States include citizens, including tribal members, with financial interests in status quo.

Legal – Since the U.S. Constitution gives Congress the power to regulate inter-state commerce, CA's law may not hold up to judicial scrutiny. If it doesn't, then this option would be withdrawn.

IV. Background data and assumptions
This option assumes legality, constitutionality and permanence of the CA law. This option would be withdrawn if the Supreme Court gives the EPA the power to regulate greenhouse gases in the case heard November 29 and if the EPA then takes a stance at least as tough as the CA standard.

V. Any uncertainty associated with the option
This option has lots of uncertainty related to political and legal feasibility.

VI. Level of agreement within the work group for this option TBD.

Mitigation Option: Net Metering for Four Corners Area

I. Description of the mitigation option

Providing electricity consumers in the Four Corners area with net-metering agreements would allow each consumer to generate their own electricity from renewable resources to offset their electricity use. A net-metering law also mandates that a utility cannot charge more for your electricity than they pay you for the solar(renewable) power you generate. Net metering would make small house/business renewable systems more feasible.

Increased capacity of renewable energy systems in the Four Corners and around the world, will lead to less need for new coal-fired power plants and their associated emissions

EPA has just released a new edition of its Emissions and Generation Integrated Resource Database (eGRID). eGRID is a comprehensive source of data on the environmental characteristics of almost all electric power generated in the United States. It contains emissions and emissions rates for NOx, SO2, CO2 and mercury. The database also contains fuel use and generation data.
In the United States, electricity is generated in many different ways, with a wide variation in environmental impact. Traditional methods of electricity production contribute to air quality problems and the risk of global climate change. With the advent of electric customer choice, many electricity customers can now choose the source of their electricity. In fact, you might now have the option of choosing cleaner, more environmentally friendly sources of energy. According to the EGRID Power Profiler, it is possible to generate a report, for example about City of Farmington electricity use. EGRID provides fuel mixes, i.e. how is our power being generated. For Farmington the mix is approximately 13% Hydroelectric, 13% gas, and 74% coal. E-GRID also provides the corresponding emissions rate estimates. For Farmington, emissions rates associated with the electricity generation (lbs/MWh) are 3.1 NO2, 3.3 SO2, and 1873 CO2

Info on E-GRID is available at http://www.epa.gov/cleanenergy/egrid

Net metering programs serve as an important incentive for consumer investment in renewable energy generation. Net metering enables customers to use their own electricity generation to offset their consumption over a billing period by allowing their electric meters to turn backwards when they generate electricity in excess of their demand. This offset means that customers receive retail prices for the excess electricity they generate. Without net metering, a second meter is usually installed to measure the electricity that flows back to the provider, with the provider purchasing the power at a rate much lower than the retail rate.Net Metering Policy:

Net metering is a low-cost, easily administered method of encouraging customer investment in renewable energy technologies. It increases the value of the electricity produced by renewable generation and allows customers to "bank" their energy and use it a different time than it is produced giving customers more flexibility and allowing them to maximize the value of their production. Providers may also benefit from net metering because when customers are producing electricity during peak periods, the system load factor is improved.

There are three reasons net metering is important. First, as increasing numbers of primarily residential customers install renewable energy systems in their homes, there needs to be a simple, standardized protocol for connecting their systems into the electricity grid that ensures safety and power quality. Second, many residential customers are not at home using electricity during the day when their systems are producing power, and net metering allows them to receive full value for the electricity they produce without installing expensive battery storage systems. Third, net metering provides a simple, inexpensive, and easily-administered mechanism for encouraging the use of renewable energy systems, which provide important local, national, and global benefits

History:
On September 30, 1999, the New Mexico Public Regulation Commission (PRC) adopted a rule requiring all utilities regulated by the PRC to offer net metering to customers with cogeneration (CHP) facilities and small power producers with systems up to 10 kilowatts (kW) in capacity. Municipal utilities, which are not regulated by the PRC, are exempt. There is no statewide cap on the number of systems eligible for net metering.

For any net excess generation (NEG) created by a customer, the utility must either (1) credit or pay the customer for the net energy supplied to the utility at the utility's "energy rate," or (2) credit the customer for the net kilowatt-hours of energy supplied to the utility. Unused credits are carried forward to the next month. If a customer with credits exits the system, the utility must pay the customer for any unused credits at the utility's "energy rate." Customer-generators retain ownership of all renewable-energy credits (RECs) associated with the generation of electricity. [from DSIRE – Database of State Incentives for Renewable Energy – New Mexico]

Benefits:
Utilities benefit by avoiding the administrative and accounting costs of metering and purchasing the small amounts of excess electricity produced by these small-scale renewable generating facilities. Consumers benefit by getting greater value for some of the electricity they generate, by being able to interconnect with the utility using their existing utility meter, and by being able to interconnect using widely-accepted technical standards.

Tradeoffs: The main cost associated with net metering is indirect: the customer is buying less electricity from the utility, which means the utility is collecting less revenue from the customer. That's because any excess electricity that would have been sold to the utility at the wholesale or 'avoided cost' price is instead being used to offset electricity the customer would have purchased at the retail price. In most cases, the revenue loss is comparable to having the customer reducing electricity use by investing in energy efficiency measures, such as compact fluorescent lights and efficient appliances.

Special meters may also cost customer some installment costs

<u>II. Description of how to implement</u>
A. Mandatory or voluntary
Utilities should be required to providing Net metering arrangements for electricity users.

B. Indicate the most appropriate agency(ies) to implement
City of Farmington Utility, other Four Corners local utilities and Coops

Two comments were received on this option during the Task Force Report Public Comment Period:

"Not only do we need net metering with our local utility (Farmington Electric Utility System), it needs to be encouraged and not expensive to sign up. These are small steps toward diversifying our energy sources, and we are in a prime solar area for generating home-based electricity."
"A net metering program would be positive if implemented with the proper subsidies to encourage citizens to get involved. Many people in the Four Corners area are not in the financial position to invest in the start-up program; this would have to come from state government programs for those who qualify."

See all the public comments received for EEREC section in the appendix to this section.

III. Feasibility of the option

A. Technical

The standard kilowatt-hour meter used by the vast majority of residential and small commercial customers accurately registers the flow of electricity in either direction. This means the 'netting' process associated with net metering happens automatically-the meter spins forward (in the normal direction) when the consumer needs more electricity than is being produced, and spins backward when the consumer is producing more electricity than is needed in the house or building. [HP magazine, Net Metering FAQs]

It may be necessary to purchase a new meter.

B. Environmental

Use of renewable energy in the Four Corners area would offset emissions generated by polluting energy sources by approximately, 3.1 lbs NO_2, 3.3 lbs SO_2, and 1873 lbs CO_2 per MWh energy production.

Solar electric and wind energy systems can be expensive; however, if a systems design approach is used taking due account of conservation and energy efficiency, the system can be profitable.

C. Economic

Solar electric and wind energy systems can be expensive; however, if a systems design approach is used taking due account of conservation and energy efficiency, the system can be profitable.

Net-metering makes good economic sense. It is a fair approach and agreement between utility and consumer to buying and selling electricity

IV. Background data and assumptions used

1 Green Power Markets, Net Metering Policies
http://www.eere.energy.gov/greenpower/markets/netmetering.shtml

2 American Wind Energy Association: http://www.awea.org/faq/netbdef.html

3 Go Solar California Net Metering
http://www.gosolarcalifornia.ca.gov/solar101/net_metering.html

4 Database of State Incentives for Renewable Energy
http://dsireusa.org

5 Home Power Magazine, Net Metering FAQs:
http://www.homepower.com/resources/net_metering_faq.cfm

6. Solar Living Source Book, John Schaeffer, 2005

V. Any uncertainty associated with the option (Low, Medium, High) Low.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups None.

Mitigation Option: New Programs to Promote Renewable Energy Including Tax Incentives

I. Description of the Mitigation Option

The Four Corners Region is recognized as having excellent solar and wind resources yet the incentives to use and develop renewable energy sources in Colorado (southwestern Colorado in particular) are extremely limited. For example, in Montezuma County, Colorado, net metering and the Federal Tax Credit for Solar Energy Systems are the only renewable energy incentives offered to residential power users. This mitigation option proposes several opportunities to diversify the incentives used to promote, develop, and increase the use of renewable energy in Colorado and other Four Corners states. The diversification of incentives will help Colorado in particular meet or exceed its current renewable energy standard (1), increase the overall use of renewable energy, reduce dependence on coal burning power sources, and reduce coal power plant emissions.

A 2003 report by the Union of Concerned Scientists gives "grades" to all states in the U.S. regarding the use and commitment to clean, renewable energy sources (2). Renewable energy sources include wind, geothermal, solar and bio-energy. In 2003, New Mexico received a grade "B+/B" (among the top 5 states in the nation) because of its commitment to increase the use of renewable energy by at least 0.5 percent per year. Currently, New Mexico has a renewable energy standard of 10 percent by the year 2011. In the same report, Colorado received a grade of "F" due to low levels of existing renewable energy and no commitment for future renewable energy development. This situation has improved since Colorado Amendment 37 passed in 2004 requiring a state-wide renewable energy standard. Colorado utilities are now required to obtain 3 percent of their electricity from renewable energy sources by 2007 and 10 percent by 2015. Even with the Colorado Amendment 37 law, incentives for encouraging the development of renewable energy in Colorado are extremely limited. There is tremendous opportunity to implement the many incentives already used in western states such as New Mexico, California and Nevada.

Incentives in this mitigation option would greatly accelerate the construction, maintenance, and expansion of solar and wind power generation. Wind and solar power sources create zero emissions of NOx, SOx, and CO2 (3). For this reason, solar and wind are the primary focus of this mitigation option.

INCENTIVES FOR RENERABLE ENERGY PROJECTS *

Incentive	Description	Incentive Currently Offered?		Who Can Implement?
		Colorado	New Mexico	Authority
Building Permit Fee Waiver for Solar Projects	Waive building permit fees when qualifying solar energy systems are installed in commercial/residential construction projects.	N	N	County/City
Leasing Solar Water Heating Systems	Service provider installs and maintains solar water heating systems for residents. Hardware owned and maintained by service provider. User pays installation fees and monthly utility fees based on system size.	N	N	Utility companies, city or county water & sanitation utilities
Renewable Energy Rebates/Credits	Rebates and/or credits (often based on system size) for purchase and	Only in a few areas,	N (?)	Utility companies

(System Costs)	installation costs of new grid-connected renewable energy systems that meet minimum energy efficiency qualifications.	including La Plata/Archuleta Counties.		
Renewable Energy Rebates/Credits (Net Metering)	Rebates and or credits for excess energy produced from grid-connected renewable energy systems.	Y	Y	Utility companies
Tax Deduction/Credit #1	Tax deduction or credit for 100% of the interest on loans made to purchase renewable energy systems or energy efficient products and appliances.	N	N	States
Tax Deduction/Credit #2	Property Tax deduction for qualifying solar photovoltaic systems.	N	N	States
Tax Deduction/Credit #3	Corporate income tax credit for companies with qualifying low or zero emissions renewable energy systems > 10 MW	N	Y	States
Tax Deduction/Credit #4	Personal income tax credit (plus Fed. Tax credit) up to 30% or $9,000 for on or off-grid photovoltaic and solar hot air systems.	N	Y	States
Sales tax exemption for Biomass Equipment and Materials	Commercial and industrial sales tax (compensating tax) exemption for 100% of the cost of material and equipment used to process biopower.	N	Y	States
Supplemental Energy Payments (SEP's)	SEPs are made for eligible renewable generators to offset above-market costs of investor-owned utilities to meet their renewable energy standard portfolio obligations.	N	N	States
Bond Programs for Public Buildings	Bonds provided to schools and public buildings to upgrade to energy efficient heating/lighting or installation of renewable energy power systems. Bonds paid back through savings on energy bills.	N	Y	States
Grant Programs	Grants provided for up to 50% of the cost of design, installation and purchase of renewable energy systems for residential and commercial/industrial	N	N	Utilities, States, residences
Energy Efficient Standards for State	Requirement for all new public building construction to achieve US	Only where economical	Y	States, local governments in

Buildings	Green Building Council Leadership in Energy and Environmental Design (LEED) ratings based on size. LEED systems emphasize energy efficiency and encourages use of renewable energy sources.	ly feasible		Colorado
Loan Programs	Zero interest loans offered for qualifying photovoltaic and solar water heat systems	Only a few locations, none in SW Colorado	N	Local communities, utilities and financial partners

* Incentives in this table were developed by comparing incentives currently used in New Mexico, California, Nevada, and Colorado (4)

Benefits: Incentives will be necessary to increase the use of renewable energy, especially for the typical residential power user. Colorado's renewable energy program is relatively new and is stimulating a developing renewable energy market. The timing is very good to implement and support a diverse incentive program to meet or exceed the State's renewable energy standard, and increase the overall use of renewable energy. An increased use of clean renewable energy will result in a corresponding decrease in NOx, SOx, and CO2 produced by coal-fired power generation.

Tradeoffs: Several incentive options would require legislation or other mechanisms of State governments and would require some time to set in place. Many incentives would be offered by State government in the form of tax incentives and may slightly decrease State tax revenues. The use of incentives listed in the above table by several western states is a good indication they work effectively and provide value to that State. They can be implemented by Colorado and other Four Corners region states.

II. Description of How to Implement

A. Voluntary or mandatory – Incentives, by definition, would be voluntary for the consumer. It could be voluntary or mandatory for the States, local government, or utility companies to offer the incentives.

B. Indicate the most appropriate agency(ies) to implement – See Incentives Table above for appropriate agency for each incentive measure.

III. Feasibility of the Option

Public and corporate knowledge regarding the environmental benefits and cost benefits of solar and wind alternative energy systems is limited, and could be greatly improved. The diversification of incentives could stimulate interest in renewable energy systems.

A. Technical: The technology for wind and solar power systems, and solar water heating and space heating is currently widely available. Improvements to make these technologies more efficient and affordable is ongoing. Using incentives to increase the use and demand for these systems would stimulate further technological advances.

B. Environmental: A 10 percent increase in the use of renewable energy in Colorado will result in a reduction of 3 million metric tons of CO2 per year in 25 years (5). It would also result in the reduction of SO2 and NOx.

C. Economic: 1) Increased demand and use of solar and wind energy systems will stimulate accelerated improvements in solar and wind energy technology and reduce costs of the technology in the long term. 2) Implementing incentives for individuals and corporate/businesses will stimulate and accelerate the use of existing wind and solar technologies. 3) Increased use through incentives will create an expanding market for producers (6), and could create up to 2,000 new jobs in Colorado in manufacturing, construction, operation, and maintenance and other industries in 25 years (5) 4) Increased use of the technology would reduce and energy costs to consumers and insulate the economy from fossil fuel price spikes (7).

IV. Background Data and Assumptions Used

(1) A renewable energy (or electricity) standard is a requirement by a state or the Federal government for utilities to gradually increase the portion of electricity they produce from renewable energy sources.

(2) Union of Concerned Scientists, 2003. Plugging in Renewable Energy, Grading the States. www.ucsusa.org/clean_energy

(3) American Wind Energy Association, 2006. Wind Energy Fact Sheet – Comparative Air Emissions of Wind and Other Fuels. 122 C Street, Washington, D.C., 2 pp.; citation for solar).

(4) Database of State Incentives for Renewable Energy (DSIRE), 2006. New Mexico, Colorado, Nevada, and California Incentives for Renewables and Efficiency. www.dsireusa.org/ ; Governor's Office of Energy Management and Conservation, 2006. Rebuild Colorado, Utility Incentives for Efficiency Improvements and Renewable Energy. www.colorado.gov/rebuildco ; Martinez, Louise, 2006. Presentation to the Four Corners Task Force – New Mexico Clean Energy Programs. New Mexico Energy, Minerals, and Natural Resource Department, presentation in Farmington NM, November 8.

(5) Union of Concerned Scientists, 2004. The Colorado Renewable Energy Standard Ballot Initiative: Impacts on Jobs and the Economy. www.ucsusa.org/clean_energy/clean_energy_policies/the-colorado-renewable-energy-standard-ballot-initiative.html

(6) Gielecki, Mark, F. Mayes, and L. Prete, 2001. Incentives, Mandates, and Government Programs for Promoting Renewable Energy. Department of Energy, 26 pgs. www.eia.doe.gov/cneaf/solar.renewables/rea_issues/incent.html

(7) Union of Concerned Scientists, 2006. Renewable Energy Standards at Work in the States. http://www.ucsusa.org/clean_energy_policies/res-at-work-in-the-states.html

V. Any Uncertainty Associated With the Option (Low, Medium, High)

Low – Increasing the use of renewable energy sources is widely accepted as a practice which will decrease air pollution emissions associated with burning fossil fuels. Increasing incentives would increase the widespread use of renewable energy systems.

VI. Level of Agreement within the Work Group for this Mitigation Option TBD.

VII. Cross-over Issues to the Other Source Groups None at this time.

Mitigation Option: Promote Solar Electrical Energy Production

I. Description of the mitigation option

A. Promote Solar Electrical Energy Production:

The region in general has good solar energy possibilities, a large number of clear days with very few successive days of clouds. If storage was not used it means that there would be power to feed to the distribution system during peak solar intensity. The power density is also quite favorable being in the range of 600 to1000 W/m2 for peak values (winter, summer). In the summer this would match the large load of air-conditioning, it would not match the winter load. Solar electrical has a developed technology with standards and while the systems are complex, especially if feedback to the power grid is done, it is not beyond the capabilities of trained people in the area.

B. Reduce Electrical Energy Consumption by Substituting Solar Energy:

The reduction of electrical energy consumption for home heating and hot water production can be replaced or supplemented by solar energy inputs. These would be significant for the individual household but these households are a small percentage of the general population. All buildings use solar energy, it is just a matter of degree. All can be improved to make better use of the solar energy which we have available, reducing other energy consumption.

II. Description of how to implement

A. Mandatory or voluntary:

Voluntary on the part of the person with the solar electric installation and with agreement of the electric utilities company, possibly with legal control by the state. Utilities would specify interconnect requirements.

B. Indicate the most appropriate agency(ies) to implement

Utilities/State

III. Feasibility of the option

A. Technical: For solar electrical systems, new inspectors would be needed or present ones reeducated. You may need a change in distribution control system.

B. Environmental: The environmental results of shifting the energy consumption from fuels (gas, oil, coal) burned in the region to solar means a reduction of all types of air pollutants by what ever reduction was achieved.

C. Economic: Not that practical unless the person is far off the grid. Would most likely need incentives (tax?). Large capital out lay to replace ongoing expenses of fuel. If other energy sources are replaced by solar, taxes will be lost.

D. Political: Since regulation and taxes may be involved this could be a problem.

IV. Background data and assumptions used:

6000-7000 heating degree days for the region
1500 cooling degree days for the region
6 usable solar hours per day (yearly average).
5 usable solar hours per day (winter average)

V. Uncertainty associated with the option (Low, Medium, High):

Low for would it work, High for could you get enough people doing it to have a significant affect.

VI. Level of agreement within the Work Group for this option TBD

VII. Cross-over issues to the other source groups None

Mitigation Option: Subsidization of Land Required to Develop Renewable Energy

I. Description of the mitigation option

Land required for larger renewable energy projects, especially solar electric energy production, would be subsidized. This option would help to promote and make renewable energy production more feasible.

BLM/FS has a large amount of unused land. Some large renewable energy projects could be demonstrated on that land. A collaborative program should be developed with US Government owners of NW NM land to provide cheap or in some case potentially free land leases to companies that are willing to develop renewable energy production facilities. Barriers should be reduced.

The Navajo Nation and other tribes in the Four Corners area own a large amount of land in the Four Corners area. There has been some interest in wind energy development on Native American land in Arizona. Available land resources on the reservation could be used to develop renewable energy projects and stimulate the local economy.

Benefits: Solar electric energy is clean energy.
Solar electric energy production could complement and eventually displace coal fired power plant electricity generation. Eventually, over time, promotion and expansion of solar electric energy production could replace the need for a new coal-fired power plant. This alternative strategy to energy production would then displace the air pollution emissions associated with that power plant.

Solar electric energy development in the Four Corners area would stimulate the photovoltaic equipment and service industry here.

Burdens: Land resource would be needed (see feasibility section). We have estimated the amount of land required to generate 1 MW of solar electric capacity.

II. Description of how to implement

A. Mandatory or voluntary
Mandatory. A rule would need to be created describing the subsidization amount and conditions.

B. Indicate the most appropriate agency(ies) to implement
Four Corners government property owners such as BLM, FS, and Navajo Nation

III. Feasibility of the option

A. Technical
The amount of land required to produce 1 MW solar electric generation capacity

For Farmington, NM a Flat-plate collector on a fixed-mount facing south at a fixed tilt equal to latitude, sees avg. of 6.3 hours of full sun. Full sun is 1,000 watts per square meter.

For our estimation we will use large Evergreen Cedar-series ES-190 W Spruce Line Module with MC Connectors, rated by California Energy Commission, http://www.consumerenergycenter.org/cgi-bin/eligible_pvmodules.cgi, at 166.8 watts output.

Based on our location in Farmington, 166.8 watts x 6.3 hours, we have a per day 1050 watt-hr per day per module. Module is approximately 61.8" x 37.5", surface area is 16.1 square feet. Allow extra space and we will need approximately 20 square feet per module.

Assume DC output to conventional AC power conversion inefficiency of 95%, CEC

1.05 KWh per module per day is reduced to approx 1 KWh at AC grid.

Conversion: 43,560 square feet in an acre
2178 modules could be fit on area of 1 acre.
This # of PV modules would generate approximately 2.2 MWh of energy.
At Farmington site this corresponds to approximately 345 KW of solar electric generation capacity.

Therefore, we could fit could generate 1 MW of electricity during daylight hours on about 3 acres of land in Farmington. Based on the solar irradiance values for Farmington this would be about 2.2 MWh of energy per day.

[Real Goods Solar Living Sourcebook, John Schaeffer, 12th edition, 2005, p.57 method of design used]

B. Environmental: Photovoltaic modules do not have significant negative environmental costs

C. Economic: Each module in example would cost approximately $1,000. There is a large amount of open land available, not in use, on government land in the 4 Corners area. Renewable energy projects could provide local jobs and help economy.

IV. Background data and assumptions used

1. California Energy Commission, http://www.energy.ca.gov/, PV specifications
2. Evergreen Solar PV module product information, http://www.evergreensolar.com/
3. Farmington, NM Solar Insolation data from San Juan College Renewable Energy Program

V. Any uncertainty associated with the option (Low, Medium, High) Low

VI. Level of agreement within the work group for this mitigation option TBD

VII. Cross-over issues to the other Task Force work groups None

Mitigation Option: Use of Distributed Energy

I. Description of the mitigation option

Distributed energy refers to decentralized generation and use of relatively small amounts of power, usually on demand in a local setting. Excess power may or may not be delivered to the grid. This option would encourage the use of distributed energy by owners of residential or commercial buildings or neighborhoods, where practical and feasible. While it is generally accepted that centralized electric power plants will remain the major source of electric power supply for the future, distributed energy resources (DER) can complement central power by providing incremental capacity to the utility grid or to an end user. Installing DER at or near the end user can also benefit the electric utility by avoiding or reducing the cost of construction of new plants to meet peak demand and/or of transmission and distribution system upgrades.

Distributed energy encompasses a wide range of different types of technologies. The Department of Energy, the state of California and various trade groups have programs encouraging research into and use of these technologies. Distributed energy technologies are usually installed for many different reasons. This option focuses on any distributed energy options that reduce demand on grid sources and thereby reduce the demand for new large power plants and/or transmission costs. While excess power generated by distributed sources and delivered to the grid can aid in reduction of power demand on centralized sources, distributed energy options are also important in serving needs in areas not currently attached to the grid thereby reducing the need for hookup to the grid.

Since these technologies are individual and/or local in nature, the burden would be on the prospective homeowner and building owner to seek out options and financing and a contractor who is sufficiently knowledgeable to suggest options and skilled enough to implement them. Initially, mortgage support or grants may also be needed to encourage implementation.

For the environmentally conscious consumer, the use of renewable distributed energy generation and "green power" such as wind, photovoltaic, geothermal or hydroelectric power, can provide a significant environmental benefit. However, the potential lower cost, higher service reliability, high power quality, increased energy efficiency, and energy independence are additional reasons for interest in DER.

II. Description of how to implement

The choice to use distributed energy resources and specifically which one(s) are appropriate should be voluntary. The decision can involve higher capital costs, and the willingness to invest in technologies that may be new and not widely implemented. Federal, state and local departments of energy should support research into options most suited to a particular geography and climate; loans and grants should be available and experts should be retained to consult with potential users.

III. Feasibility of the option

A. Technical – Information on various choices is available, choices range from low-tech to high-tech
B. Environmental – Any options that reduce the demand on the centralized power grid and minimize their own pollution will contribute to an improved environment by reducing the need for coal-fired power plants in our area
C. Economic – Options range in cost. Greater use of options should ultimately result in reduced unit costs
D. Political – Use of distributed energy resources should be an easy sell politically; the degree to which federal and state research and resources are already available, indicates a public commitment already in place

IV. Background data and assumptions N/A

V. Uncertainty – This option has a high degree of certainty that it could be implemented and be effective.

VI. Level of agreement within the work group for this option TBD

VII. Cross-over issues to the other source groups None at this time.

CONSERVATION

Mitigation Option: Changes to Residential Energy Bills

I. Description of the mitigation option

Energy for many households in the four corners area is delivered as electricity and/or natural gas. Residential energy is used for home heating, hot water, and to run appliances. Most residential consumer receives monthly bills. Examples of typical electric and gas bills are shown in Figures 1 and 2, respectively.

Figure 1. Residential electric utility bill with sample energy cost savings

Electric Association Bill (Colorado)									
Account Information									
SERVICE DATE		NO. DAYS	RTE/SEQ	METER READING		MULTI PLIER	kWh USAGE	CHARGES	
PREVIOUS	PRESENT			PREVIOUS	PRESENT				
9/18/2006	10/16/2006	28	403-160	1	612	1	612		
				LAST AMOUNT BILLED				95.07	
				PAYMENT MADE -- THANK YOU				95.07	CR
				…….					
				ENERGY CHARGES				54.30	
				CITY TAX				2.97	
				BASIC CHARGE				15.50	
				FRANCHISE FEE				3.49	
				TOTAL CURRENT CHARGES				76.26	
COST COMPARISON	DAYS SERVICE	TOTAL kWh	AVG. kWh/DAY	kWh COST/DAY					
CURRENT BILLING PERIOD	28	612	22	2.72		TOTAL DUE		76.26	
PREVIOUS BILLING PERIOD	34	806	24	2.24		BILLING DATE:		10/20/2006	
SAME PERIOD LAST YEAR	28	676	24	2.72		DUE DATE:		11/6/2006	
Example of possible cost savings for an electric hot water heater									
Most efficient	4622	kW/yr							
Anticipated monthly saving in kWh/yr			21	kWh					
Monthly dollar saving @ your rate of 12.5 cents / kWh			2.65						
Savings over a 13 year life			412.78						

Figure 2. Residential gas utility bill with sample energy cost savings

Energy (gas) Company Bill (Colorado)									
			DATE OF SERVICE		METER READING				
BILLING INFORMATION:			FROM	TO	PREVIOUS	PRESENT			
METER DEPOSIT	347.00		10/02/06	11/01/06	9750	9845			
PREVIOUS BALANCE			RATE CODE:	36QC					
			USAGE IN CCF:	78					
CURRENT GAS CHARGE TOTAL		85.15	PRESSURE FACTOR:		0.819				
FACILITY CHARGE	21.50			Usage this month		95	therms		
COM LDC COST @ .16000/CCF	12.45			Example of possible cost savings for a gas hot water heater					
UPSTREAM COST @ .02530/CCF	1.97			Most efficient		230		therms/year	
COMMODITY COST @ .67930/CCF	52.86			Anticipated monthly saving in therms				4	kWh
DEFERRED GAS COST @ -.09880/CCF	-7.69			Monthly dollar saving @ your rate of 0.97 cents				3.88	
FRANCHISE FEE @ .05000	4.06			Savings over a 13 year life				605.28	
SERVICE CHARGE TOTAL		0.54							
PENALTY	0.54								
TAX TOTAL									
STATE TAX @ .02900	2.47								
CITY TAX @ .04050	3.44								
COUNTY TAX @ .00450	0.38								
CURRENT CHARGES		91.98							
TOTAL AMOUNT DUE		91.98							

A typical energy bills lists meter readings, cost breakdowns, and other technical information. Much of the information on monthly energy statements is required by regulatory bodies and laws. Most importantly, a typical bill does not provide the consumer with information to make decisions on energy conservation and the ability to translate proposed conservation options to dollars saved.

The suggested mitigation option is to have an additional place on monthly bill that would feature one energy conservation step that a consumer may take and indicate cost savings. In the examples presented, a cost saving for a new energy efficient hot water heater is shown (bold box in Figure 1 and in Figure 2). Another monthly statement could show the amount of savings that may result from lowering the thermostat one degree Fahrenheit. A statement of energy saving on the bill would be more effective that simply including a generic insert in the bill. These often are quickly discarded.

In addition, we recommend that all energy bills have a graph that shows 1) year to month energy used for the current and past year and monthly use comparing the current to the previous year.

II. Description of how to implement

A. Mandatory or voluntary: Voluntary
B. Indicate the most appropriate agency(ies) to implement:
Energy companies

III. Feasibility of the option

A. Technical: Some reprogramming of residential energy billing program
B. Environmental:
C. Economic: Cost of reprogramming software

IV. Background data and assumptions used

V. Any uncertainty associated with the option (Low, Medium, High) Medium

VI. Level of agreement within the work group for this mitigation option: TBD

VII. Cross-over issues to the other Task Force work groups: Unknown

Mitigation Option: County Planning of High Density Living as Opposed to Dispersed Homes throughout the County

I. Description of the mitigation option
San Juan County is presently starting the process of developing a county wide growth master plan. A number of questions in their citizens questionnaire were if there should be encouragement or restrictions in development of home sites in the rural areas of the county and if this growth should be low or high house value. From the point of view of energy conservation and hence reduced pollution of many types the county should be encouraged to develop a plan which encourages clustering of housing (not in the far rural areas) so as to reduce energy losses on distribution lines and the reduction of travel distances for transportation. The ideal clustering should be near employment and services. Other counties in the Four Corners should be encouraged to also follow this pattern.

II. Description of How to Implement:
A. Mandatory or voluntary
While you cannot force people to do this, encouragement by tax policies, varying rates based on distances for electrical services, zoning or other methods would be helpful.
B. Indicate the most appropriate agency(ies) to implement

Taxes and zoning would be under the county government while the rates would be with the electric utilities companies of allowed by law. I do not know how much latitude they have.

III. Feasibility of the option
A. Technical: No problems

B. Environmental: None until specifics are assumed.

C. Economic: Concentrated populations, within limits, will have an advantage of reduced infrastructure coast.

D. Political: The greatest problem with this option will be general resistance to the ideal by the general public and very great resistance from those with vested interest.

IV. Background data and assumptions used San Juan county citizens' questionnaire.

V. Uncertainty associated with the option (Low, Medium, High) TBD.

VI. Level of agreement within the Work Group for this option TBD.

VII. Cross-over issues to the other source groups None at this time.

Mitigation Option: Direct Load Control and Time-based Pricing

I. Description of the mitigation option

Overview

This option describes demand response tools focused on direct load control and electric pricing. By offering direct load control and electric pricing options around time-of-day, critical peak and seasonal use, customers are provided with an effective price signal regarding when and how they use electricity. Demand response ("DR") is the label currently given to programs that reduce customer loads during critical periods. In the past, DR programs have also been called "load management" and "demand-side management" programs. Most demand response programs currently focus on either peak load clipping through direct load control or load shifting through time-based pricing mechanisms. The primary goal of DR programs is to reduce peak demand. The concerns regarding impending major capital expenditures by utilities for additional generating and transmission system capacity and the impact of energy consumption on the environment has sparked a renewed interest in utility programs to reduce the amount of energy used during periods when the generation and power delivery infrastructures are most constrained and at their highest costs. Reductions in peak demand may or may not be accompanied by a reduction in the total amount of energy consumed. This is because DR programs may result in energy consumption simply being shifted to a period when the utility system is not as constrained and market prices are lower.

Air Quality and Environmental Benefits- Demand response programs primary purpose is to reduce peak load. These programs may not lead to energy conservation nor should they be relied upon to do so (Energy efficiency programs are specifically designed to reduce the total amount of energy used by customers on an annual basis).
These programs may allow utilities to hold off on building new generating plants and permit technology to develop and mature in the areas of clean coal generation as well as renewable energy.
(As an indirect benefit, if customers do choose to conserve energy, the reduction in energy use may lead to a reduction in the need for energy generation resulting in emission reductions in air pollution and greenhouse gases).

Economic: Customer charge for the installation and use of automatic metering systems (where applicable) installed in participating residential and commercial customer homes and businesses
Cost to utility for administration and tracking of the program.

Trade-offs: Positive public relations, clean coal and renewable technology maturation

II. Description of how to implement

Mandatory or voluntary: Voluntary
Time of use pricing: Electricity is priced at two different levels depending upon the time of day. The inverted block rate is a rate design for a customer class for which the unit charge for electricity increases from one block to another as usage increases and exceeds the first block. The incentive is to use less energy and stay within the first block, which has the lowest rates.

Critical peak pricing: Critical peak pricing is a pricing scheme that encourages customers to reduce their on and mid-peak energy usage by offering incentives through an alert-based, monitoring system.

Seasonal use pricing: Electric rates vary depending upon the time of year. Charges are typically higher in the summer months when demand is greater and the cost to generate electricity is higher. For example, during the months of June through September, electricity rates would be higher than other months.

The public utility commission is the most appropriate entity to implement.

III. Feasibility of the option

Technical: Good feasibility. Programs have been applied and demonstrated at utilities across the country. Automated and advanced metering systems are commercially available.

Environmental: Medium feasibility for indirect benefits. Prices and advanced metering systems can be used to modify customer behavior to use less electricity within individual homes and businesses during peak hours. This may or may not lead to energy conservation. However, such programs may allow utilities to hold off adding new generation assets, thereby, improving opportunities for employment of more advanced, demonstrated and cost-effective clean coal and renewable energy technology.

Economic: Good economics. Advanced metering systems, in addition to better enabling time-based rates, can deliver load control signals to end-use equipment and provide consumers with energy consumption and price information to assist with shifting load from on-peak to off-peak periods, thereby saving the customer money on their utility bills. Direct load control and electric pricing options create long-term market transformations by shifting energy use to periods of lower plant and infrastructure constraints as well as lower market cost. As a result, utility maintenance and equipment replacement costs may be reduced and the cost to build new generation may also be postponed.

IV. Background data and assumptions used

Energy Administration Information, Department of Energy

Federal Energy Regulatory Commission, "Assessment of Demand Response & Advanced Metering"

Conservation is not the purpose of direct load control and electric pricing options. Energy efficiency programs are better suited to promote conservation.

V. Any uncertainty associated with the option (Low, Medium, High) Medium. Voluntary programs do not guarantee energy conservation and emissions reductions.

VI. Level of agreement within the work group for this mitigation option Good. This option write-up stems from a discussion at the November 8, 2006 meeting of the Power Plant Working Group.

VII. Cross-over issues to the other source groups (please describe the issue and which groups)

Other Sources Group- Pilot Neighborhood Project to Change Behavior to Reduce Energy Use and Energy Efficiency Programs

Mitigation Option: Energy Conservation by Energy Utility Customers

I. Description of the mitigation option

This option would require all generators of power (renewable and non-renewable sources) in the Four Corners area to develop a program which causes their customer base to reduce per capita power usage each year for five years until an agreed upon endpoint is reached. The owners of all facilities that generate power, irrespective of how it is generated, should be required to develop or participate in a program which encourages their customer base to reduce per capita, per household, per production unit (or whatever other measure is equivalent for non-residential customers) use of power each year for five years until some reasonably aggressive endpoint is reached. The percent annual reduction would be 20% of the difference between the baseline usage and the five year goal.

The goal or endpoint would be negotiated between industry trade groups, governmental agencies, environmental groups and interested parties and would vary depending on the climate at the location of the customer base. The set of endpoints thus determined would apply industry-wide and always be a challenge. Most measures observed to date depend on a percent reduction in per unit usage. The difference in this option is that the endpoint for each customer base is a specific achievable minimum amount of energy usage based on current technology.

This concept is similar to water conservation programs, which have successfully reduced water usage. Water companies have used incentives to promote the use of water saving devices – low water flush toilets, controls on shower heads, more efficient outdoor sprinkling systems.

Power generators could develop their own programs or join together with other power producers in a consortium to implement a program. Customers could be rewarded with financial incentives such as reduced costs per unit for reduced levels of usage and/or lesser rates for power used at off-peak times of the day or week. Conservation credits could be traded as in the pollution credit trading program as long as the caps were reduced each year until the overall goal for that customer base is met.

A web site devoted to success and failure of conservation incentive programs, publicizing the progress of each power plant could impact compliance by affecting shareholder decisions, among other things. The American Council for an Energy Efficient Economy has a start on this with their study 'Exemplary Utility-Funded Low-Income Energy Efficiency Programs' (www.aceee.org).

The burden of this requirement would be on the power generators and indirectly on the customer base. The goals for each power generating plant should be aggressive but attainable for their customer base. When a plant has multiple customer bases, appropriate goals should be set for each base separately, in consideration of differences in climate.

II. Description of how to implement

This rule should be mandatory for all power generators. Many power generators have such programs now but should be required to look at best practices (most cost-effective programs) for these programs and implement them.

A loan-incentive program may be needed to help owners of large buildings replace costly appliances such as hot water heaters, refrigerators, heating and air conditioning units, which can achieve high energy savings.

III. Feasibility of the option

Technical: Programs motivating conservation exist.

Environmental: The environmental benefits include reduced pollution which accompanies reduced power generation relative to what it would have been either at peak times or over time, depending on success of customer conservation program. Over time fewer power generating facilities would need to be built (or older inefficient units could be retired sooner)
Economic: Programs will cost money, but they are cost-effective (see data below). Implementation could be contracted out
Political: Probably minimal challenge in getting this requirement passed, this is pretty innocuous; and the public relations campaign around conservation would educate consumers as to their role and potential impact on reducing greenhouse gases, reducing air pollution and improving air quality

IV. Background data and assumptions
(1) Southwest Energy Efficiency Project (SWEEP): Highlights taken from SWEEP's website, http://www.swenergy.org/factsheets/index.html:

The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest examines the potential for and benefits from increasing the efficiency of electricity use in the southwest states of Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming. [Unfortunately, California is not included.] The study models two scenarios, a "business as usual" Base Scenario and a High Efficiency Scenario that gradually increases the efficiency of electricity use in homes and workplaces during 2003-2020.

Major regional benefits of pursuing the High Efficiency Scenario include:

- Reducing average electricity demand growth from 2.6 percent per year in the Base Scenario to 0.7 percent per year in the High Efficiency Scenario;
- Reducing total electricity consumption 18 percent (41,400 GWh/yr) by 2010 and 33 percent (99,000 GWh/yr) by 2020;
- Eliminating the need to construct thirty-four 500 megawatt power plants or their equivalent by 2020;
- Saving consumers and businesses $28 billion net between 2003-2020, or about $4,800 per current household in the region;
- Increasing regional employment by 58,400 jobs (about 0.45 percent) and regional personal income by $1.34 billion per year by 2020;
- Saving 25 billion gallons of water per year by 2010 and nearly 62 billion gallons per year by 2020; and
- Reducing carbon dioxide emissions, the main gas contributing to human-induced global warming, by 13 percent in 2010 and 26 percent in 2020, relative to the emissions of the Base Scenario.

These significant benefits can be achieved with a total investment of nearly $9 billion in efficiency measures during 2003-2020 (2000 $). The total economic benefit during this period is estimated to be about $37 billion, meaning the benefit-cost ratio is about 4.2. The efficiency measures on average would have a cost of $0.02 per kWh saved.

The High Efficiency Scenario is based on the accelerated adoption of cost-effective energy efficiency measures, including more efficient appliances and air conditioning systems, more efficient lamps and other lighting devices, more efficient design and construction of new homes and commercial buildings, efficiency improvements in motor systems, and greater efficiency in other devices and processes used by industry. These measures are all commercially available but underutilized today. Accelerated adoption of these measures cannot eliminate all the electricity demand growth anticipated by 2020 in the Base Scenario, but it can eliminate most of it.

(2) US Department of Energy – Energy Efficiency and Renewable Energy, a consumer's guide: http://www.eere.energy.gov/consumer/ List of suggestions for consumers includes many of the items mentioned in SWEEP's High Efficiency Scenario and focuses on proper operation of the items.

<u>V. Uncertainty</u>
No uncertainty about benefits of conservation; moderate uncertainty about how much consumers will cooperate and actually conserve.

<u>VI. Level of agreement</u> TBD.

<u>VII. Cross-over issues</u>
Need discussion as to how it would fit into Oil and Gas Group's sources

Mitigation Option: Outreach Campaign for Conservation and Wise Use of Energy Use of Energy

I. Description of the mitigation option

Conservation is an important strategy for mitigation air pollution in 4 Corners area. An outreach campaign centered on this strategy would help to educate public and industry and lead to more conservation actions. This would lead to a sustainable future, reduce dependence on fossil fuels, and help to mitigate air pollution in the Four Corners area.

Conservation is defined as the sustainable use and protection of natural resources including plants, animals, minerals, soils, clean water, clean air, and fossil fuels such as coal, petroleum, and natural gas. Conservation makes economic and ecological sense. There is a global need to increase energy conservation and increase the use of renewable energy resources.

Coal fired power plants are the nation's largest industrial source of the pollutants that cause acid rain, mercury poisoning in lakes and rivers and global warming. Utilizing renewable energy sources such as wind and solar and improving energy efficiency in appliances, business equipment, homes, buildings, etc. will theoretically reduce pollution from coal fired power plants. Of course, installation of best management pollution control equipment on existing coal fired power plants will be most beneficial.

Renewable energy alternatives such as solar, water, and wind power and geothermal energy are efficient and practical but are underutilized because of the availability of relatively inexpensive nonrenewable fossil fuels in developed countries. Conservation conflicts arise due to the growing human population and the desire to maintain or raise the standards of living.

Up until now, consumer behavior has been motivated by cheap and plentiful energy and not much thought has been given to the degradation of the environment. Production and use of fossil fuels damage the environment. The supply of nonrenewable fossil fuels is limited and is rapidly being used up. Fossil fuel is becoming more expensive. Reality is beginning to set in. There is a need for safe, clean energy production, renewable energy alternatives, and conservation. Energy supplies and costs will restructure consumer usage.

Federal and State agencies and the utility companies need to focus on more public awareness and provide information on available tax credits for solar, photovoltaic, and solar thermal systems. There are also tax credits available to homeowners for replacement of older air conditioners, heat pumps, water heaters, windows, and installation of insulation. There are tax incentives for the purchase of hybrid automobiles.

All of this information is available on web sites, tax forms, agency handouts, etc. but, more than likely, the average citizen is unaware. Since alternative energy and conservation have moved to the forefront, the public needs information. Public service announcements on TV, radio and newspapers and informational mailings in consumer energy billings would be most helpful.

School children should be included in the energy information process. There is a program for grades K - 4 titled "Energy for Children - All about the Conservation of Energy" with a teacher's guide that is available on www.libraryvideo.com.

The educational programs need to start in elementary school (or earlier) and continue through high school. There are some really great opportunities for curriculum development in energy conservation that would integrate several disciplines including biology, math, and social studies. I think NM has done the best job of this among the four corner states and hope that it will be expanded to the other states. It would be good just to have a group review K-12 materials, see what gaps exist and how information, including successes can be promulgated. Perhaps this has been done - a web site is a good start.

A Google search of "conservation of energy resources" has a very large website database.

Volunteer groups are working to improve the energy efficiency of homes occupied by the elderly and by people who are unable and/or cannot afford to make home improvements.
Communities could work toward increasing the volunteer workforces and the resources for this much needed humanitarian service.

The future belongs to our children and grandchildren. What we have done in the past and what we do in the here and now, has a direct impact on the environment that future generations will inherit.

II. Description of how to implement
A. Mandatory or voluntary
Voluntary at grassroots and governmental levels
Some mandatory curriculum could be developed for schools as part of educational component

B. Indicate the most appropriate agency(ies) to implement
Local Governmental Energy and Air Quality Agencies. Schools

III. Feasibility of the option
A. Technical: We must clearly demonstrate the problems and potential solutions

B. Environmental: Conservation has been shown to reduce energy use

C. Economic: Outreach program must demonstrate the short term economic benefits. Also design program to benefit low-income citizens. Government needs to provide some economic incentives to help kick start conservation programs

IV. Background data and assumptions used N/A.

V. Any uncertainty associated with the option Low.

VI. Level of agreement within the work group for this mitigation option TBD.

VII. Cross-over issues to the other Task Force work groups All Work Groups.

CROSSOVER OPTIONS

Mitigation Option: Bioenergy Center

(Reference as is from Power Plants: see Future Power Plants section)

Mitigation Option: Biomass Power Generation

(Reference as is from Power Plants: see Future Power Plants section)

Mitigation Option: Utility-Scale Photovoltaic Plants

(Reference as is from Power Plants: see Future Power Plants section)

ENERGY EFFICIENCY, RENEWABLE ENERGY AND CONSERVATION: PUBLIC COMMENTS

Energy Efficiency / Renewable Energy / Energy Conservation Public Comments

Comment	Mitigation Option
Advanced metering for home owners will not work. It will only enrich the electric companies who will use the data to set rates higher when people need the energy. An alternative is rolling blackouts on house AC's like that used in the Houston, TX area.	Advanced Metering
Using combined heat and power could be an effective method to increase efficiency and reduce emissions.	Cogeneration/Combined Heat and Power
The Four Corners region has a huge potential to develop renewable energy resources. Moreover, our resources are not limited to good sun and the region's many windy plateaus. Our citizenry possesses a large body of technical expertise, many of whom already work in energy and electrical power generation. We also have mechanical expertise and a pre-existing industrial infrastructure at our hands. Last, we are extremely well-suited to implement educational programs for renewable energies. Dineh College, San Juan College, and Fort Lewis College are obvious examples. This option can also sustain us beyond the inevitable decline in oil and gas production, as well as providing a means for younger generations to stay and work in their home areas (which is especially problematic in La Plata County.) Last, this possibility fits neatly with the previous recommendation for a regional planning board or authority. In short, we have every reason in the world implement renewable energy as a regional industry.	Renewable Energy
Pure protectionism, not good energy policy. The NIMBY attitude will never solve problems. If you want clean energy, do it the right way, build nuclear. I notice that this option never came up why?	Four Corners States Adopt California Standards for Purchase of Clean Imported Energy
Not only do we need net metering with our local utility (Farmington Electric Utility System), it needs to be encouraged and not expensive to sign up. These are small steps toward diversifying our energy sources, and we are in a prime solar area for generating home-based electricity.	Net Metering for Four Corners Area
A net metering program would be positive if implemented with the proper subsidies to encourage citizens to get involved. Many people in the Four Corners area are not in the financial position to invest in the start up program; this would have to come from state government programs for those who qualify.	Net Metering for Four Corners Area

Cumulative Effects

Cumulative Effects: Preface

Overview

The Cumulative Effects work group was charged with assisting the source work groups to understand current and future air quality conditions in the region, using existing information. The cumulative effects workgroup was also to assist the other work groups in performing their analysis of the mitigation strategies being developed, within the scope of the Task Force's timeframe and resources. The Cumulative Effects work group was also tasked with suggesting ways for filling technical gaps and addressing uncertainties as identified by the other work groups.

The Cumulative Effects work group was a small group with approximately a half dozen active members representing state governments, tribal governments, local citizens, industry, and the federal government.

Scope of Work

The following was the original scope of work for the Cumulative Effects (CE) work group.

Specific Tasks:

1. Evaluate air quality effects of candidate mitigation measures as requested by other Task Force work groups, or provide guidance on how candidate mitigation measures could be evaluated.
2. Prepare overarching cumulative estimate of the air quality effects from implementation of all the Task Force recommended mitigation measures.
3. Describe a "gold standard" for the best technical analyses that can be done, and provide recommendations for future analyses. Describe the uncertainty associated with the air quality estimates.
4. Respond to issues referred to the CE work group from other work groups.
5. Recommend additional analysis, studies, etc. that may be necessary for the CE work group to fully carry out its tasks. For example, the CE may feel that it is necessary to conduct an ozone precursor field study with advice from the monitoring group, or an ammonium field study for particulate matter.

Discussion

In accomplishing #1, the Cumulative Effects work group was charged with assessing upwards of 20 of the numerous mitigation options being proposed by the source-related work groups. For these options, the emissions reductions associated with undertaking the mitigation approach have been estimated. In addition, the work group also detailed methods, assumptions, limitations, and sources of information.

All of the tasks associated with estimating emissions reductions were relative to the oil and gas sector. In order to make much of this work as accurate as possible, the Cumulative Effects work group undertook improvements to the base case inventory for drilling and production activities in the Four Corners region. The base case inventory shows what current and future emissions would be in the absence of additional air pollution mitigation. The best data from the Western Regional Air Partnership (WRAP), the States of New Mexico and Colorado, the Southern Ute Indian Tribe, and industry participants were consolidated and quality assured to create a more accurate and complete inventory than previously existed. Using estimates of the effectiveness of the various mitigation options and applying them to the base case, estimates of the number of tons of pollution that would be reduced by each mitigation option were calculated. Emissions reductions associated with mitigation options directed and motor vehicles used in oil and gas activities were also estimated.

Because of the length of time and resources required to set up modeling analyses and to accomplish them, the modeling task (#2) was moved outside the Task Force process. It will inform regulatory agencies of the air quality benefits of options after the Task Force report is completed. The approach taken is akin to the “gold standard,” and thus #3 was addressed as part of the agencies’ modeling effort.

Consistent with #4, the Cumulative Effects work group also responded to requests for additional information relative to a few of mitigation options, for example, answering questions about monitoring at a power plant and providing a bit more detailed description of overall emissions.

Related to #5, suggestions for future research associated with implementation of the mitigation options are presented, for example, with regard to the sources and impacts of ammonia emissions and the economic effect of various mitigation option

OVERVIEW OF WORK PERFORMED

The Cumulative Effects (CE) work group was requested to provide information on a number of mitigation options described by the source work groups. Table 1 summarizes the reasons why the Cumulative Effects work group may or may not have researched a particular question, and a brief description of the outcome if work was performed.

Table 1: Summary of mitigation option findings.

OPTION	ACTION TAKEN BY CE	SUMMARY OF RESULT
Tax or Economic Incentives for Environmental Mitigation	CE did not have expertise to address this option.	No action.
Selective Catalytic Reduction (SCR) on Drilling Rig Engines	There was insufficient time to address this option.	Some data exists on drilling emissions. The State of Wyoming evaluated this technology based on a pilot study in the Jonah Field & concluded that is not a cost effective technology, but further analysis is needed.[1]
Implementation of EPA's Non Road Diesel Engine Rule – Tier 2 through Tier 4 Standards for Drilling Rigs	There was insufficient time to address this topic.	An important piece of information is that these engines typically last 4-10 years and then need to be replaced. This means that there will be a constant infusion of new technology engines over time. However, faster turnover would reduce emissions in the near-term.
Industry Collaboration for RICE	This option was not evaluated because it is not possible to quantify emission reductions.	No action.
Install Electric Compression for RICE	This option was evaluated.	Replacement of low emission engines with electric power grid would result in an overall increase in emissions. A reduction in NOx emissions would occur, however, there would be an increase greenhouse gas emissions due to increased electrical generation requirements.
Follow EPA Proposed New Source Performance Standards (NSPS) for RICE	This option was evaluated.	This proposed emission standard will become the baseline for new modified and reconstructed engines. Future year projections indicate that these standards will minimize growth in oil and gas emissions from natural gas fired engines.
Install Selective Catalytic Reduction (SCR) on Lean Burn Engines for RICE	This option was evaluated.	There is very little information on the installation of this control technology on natural gas fired engines. What is available indicates that in the Four Corners area the installation of this technology would result in small NOx reductions. In addition, the cost to control emissions would be relatively high.[2] **Differing Opinion:** Disagree with the last two sentences.
Install Non Selective Catalytic Reduction (NSCR) on Rich Burn Engines for RICE	This option was evaluated.	It was found that installation of NSCR on small engines could reduce NOx emissions significantly. The USEPA performance standard for rich burn engines will likely require installation of NSCR for new, modified and reconstructed rich burn engines.

OPTION	ACTION TAKEN BY CE	SUMMARY OF RESULT
Install Lean Burn Engines for RICE	This option was evaluated.	Emission inventory data indicated that on large engines of greater than 500 horsepower this technology or NSCR is already being used on the majority of the engines in the region. The use of these engines results in significant reductions in NOx over the use of rich burn engines, and may be beneficial when applied to smaller engines.
Install Selective Non Catalytic Reduction (SNCR) for RICE	This option was evaluated.	It was determined that this technology is unlikely to be used because it is less effective than SCR or NSCR.
Install Oxidation Catalyst on Lean Burn Engines for RICE	This option was evaluated.	This mitigation option was evaluated in terms of HAPs emissions and VOCs. Previous modeling analyses indicated that HAPs impacts are localized. It was found that VOC emission reductions would be primarily methane and ethane which have a low photochemical reactivity, and likely do not contribute to ozone formation. **Differing opinion:** Contest the previous statement as to accuracy. Methane is a greenhouse gas and reduction of methane emissions is desirable in combating global climate change.
Install Optimized/Centralized Compression	This option was evaluated.	It was concluded that there would be no opportunities for reducing emissions as a result of implementing this option.
Next Generation Control Technology for RICE	This option was evaluated.	Because these technologies are emerging, it is not possible to quantify the additional benefits of controls.
Automation of Wells to Reduce Truck Traffic	This option was evaluated.	Potential fugitive dust emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.
Centralized Produced Water	This option was evaluated.	Potential fugitive emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.
Efficient Routing of Water Trucks	This option was evaluated.	Potential fugitive emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.
Cover Lease Roads with Rock or Gravel	This option was evaluated.	Potential fugitive emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.
Enforcing Speed Limits on Dirt Roads	This option was evaluated.	Potential fugitive emission reductions were evaluated. The effect of dust emissions which are primarily PM10 is not regional. Although there are dirt roads over much of the area, impacts will be localized.

OPTION	ACTION TAKEN BY CE	SUMMARY OF RESULT
Selective Catalytic Reduction (SCR) NOx Control Retrofit	This option was not evaluated.	Only emission reductions were estimated, not effects on visibility or ozone, so could be done as a part of future work.
Emissions Monitoring for Proposed desert Rock Energy Facility to be Used Over Time	This option was assessed.	The option was looked at by the CE Work Group, and an assessment included.
Declining Cap and Trade Program for NOx Emissions for Existing and Proposed Power Plants	This option was not evaluated.	Only emission reductions were estimated, not effects on visibility or ozone, so could be done as a part of future work.
Chronic Respiratory Disease Study for the Four Corners Area	A brief look at the data was done.	A summary of ozone trends generally showed an upward trend. Another look at this question will be provided by future work.
Install Electric Compression	This option was evaluated.	See above.

Emissions Summary

The overall emissions of nitrogen oxides (NOx) and volatile organic compounds (VOC) broken into broad source categories can provide some perspective when reductions from various mitigation options are presented in subsequent sections. Table 2 shows the relative importance of groups of sources in the Four Corners region:

Table 2: Percentage of total future year emissions in 2018 by pollutant.

SOURCES	NOx EMISSIONS (%)	VOC EMISSIONS (%)
Mobile	2	5
Area	1	23
Oil & Gas	26	32
Power Plants	40	1
Other Point Sources	30	39

This table demonstrates that oil and gas production, electrical generation, and other industrial activities are the largest emitters of nitrogen oxides, while oil and gas production, industrial facilities other than those related to power plants and oil and gas production, and area sources emit the majority of VOC. Area sources are those industrial and commercial activities that are small enough to not be required to obtain an air quality permit to operate. Area sources also include a broad range of human activities that result in small amounts of pollution on an individual basis.

The data presented in Table 1 have been derived primarily from the Western Regional Air Partnership (WRAP) emission inventory. For these categories, the Four Corners Air Quality Task Force requested an extraction from the WRAP regional database for the Four Corners area that encompasses portions of Colorado, New Mexico, Arizona, and Utah. The one exception is for oil and gas sources, which were estimated using updated information developed by the Cumulative Effects work group.

Emissions Reduction Summary

Table 3 summarizes emission reductions for mitigation options for which the estimates were made in order to facilitate comparison. Some estimates were made by the Cumulative Effects work group for the Oil and Gas work group, while some were made by the Power Plants (PP) work group for their own options. Descriptions of the mitigation options and how the estimates were derived can be found in the section of each work group, respectively.

Table 3: Mitigation Option Summary

Mitigation Option	Work Performed By	Pollutant Reduced	Reduction Estimate (tpy)
Control Technology Options for Four Corners Power Plant	PP	NOx	11,688
Control Technology Option for San Juan Generating Sta.	PP	NOx	6,166
Enhanced SO2 Scrubbing	PP	SO2	2,083
Selective Catalytic Reduction (SCR) NOx Control Retrofit	PP	NOx	29,987 to 46,684
BOC LoTOx System for Control of NOx Emissions	PP	NOx	43,257
Baghouse Particulate Control Benefit	PP	PM10	465
Declining Cap and Trade Program for NOx Emissions	PP	NOx	3,428
Install Electric Compression w/ Grid Power	CE	NOX & SO2	Variable – See note below
Install Electric Compression w/ Onsite Gen Power	CE	NOX & SO2	12,000 to 40,721
Use of NSCR for NOx Control on Rich Burn Engines	CE	NOx	16,588 to 21,327
Use of SCR for NOx Control on Lean Burn Engines	CE	NOx	Insufficient information to quantify
NSPS Regulations	CE	NOx	0
Optimization/Centralization	CE	NOx	0
Use of Oxidation Catalyst for Formaldehyde & VOC Control on Lean Burn Engines	CE	VOC	1619
Automation of Wells to Reduce Truck Traffic	CE	PM10 & NOx	196 & 92
Reduced Truck Traffic by Centralizing Produced Water Storage	CE	PM10	39
Reduced Truck Traffic by Efficiently Routing Produced Water Disposal Trucks	CE	PM10	196
Reduced Vehicular Dust Protection by Covering Lease Roads with Rock or Gravel	CE	PM10	206
Reduced Vehicular Dust Production by Enforcing Speed Limits	CE	PM10	73

Note: Some engine configurations are as efficient as current coal-fired generating stations without being subject to line losses, whereas other engines would be less efficient than using commercially available line power.

Suggestions for Future Work

As the Cumulative Effects work group completed the tasks of evaluating mitigation options, it became clear that there is a need for future work to provide regulatory agencies additional information on the benefits of reducing pollution emissions into the air in the Four Corners region. Additional detailed modeling is planned by the agencies that will provide more refined information regarding the actual effects of proposed mitigation programs. The modeling analysis is scheduled for completion in the fall of 2007. Leading into the analysis of mitigation programs, some updating of source information will be necessary. An example would be for drilling rigs.

To supplement the modeling analyses, additional monitoring of pollutants and meteorology throughout the Four Corners region would be useful. This monitoring would provide a basis for establishing whether model predictions are accurate and would help determine air quality trends. Currently, there are relatively few air monitoring sites in the Four Corners region to use in testing model performance. Monitoring for ammonia would be particularly useful as it enhances the ability of the model to estimate the effects of air pollutant emissions on visibility.

The Cumulative Effects work group was required to delve into agency emissions inventories in detail, and this work exposed many weaknesses in state and tribal inventories. For future analysis of options, it is recommended that states and tribes require more robust reporting of industrial entities, including reporting of facilities that may currently fall below permitting or reporting thresholds. States and tribes may require regulatory changes to reporting requirements to accomplish this. Lack of detailed reported data introduces a high level of uncertainty into analysis of options for mitigation. State and tribal agencies need to be able to quantify cumulative reductions with certainty in order to appropriately evaluate and prioritize options. By performing analyses that combine trends in emissions with trends in monitoring data, information may be identified regarding source receptor relationships.

The work group also recommends a review of existing field test data and an expansion of the existing state and tribal field testing programs for source emissions. Improvement of inventory emissions estimates will result in better modeled estimates of air pollution concentrations. A focused effort to obtain and share emissions data from a variety of oil and gas engines under different operating conditions would be particularly beneficial in inventory improvement.

Finally, the work group recommends that economic analysis of options be conducted to provide cost/benefit information to state and tribal agencies. The work group did not have the time or resources to conduct economic modeling, but economic data is of great importance in analyzing and prioritizing options. Such modeling could analyze "bundled" options to minimize analysis costs.

Endnotes:

1 Personal communication between Reid Smith (BP) and David Finley (WDEQ).

2 EPA Speciate data for natural gas-fired engines.

DETAILED DESCRIPTIONS OF MITIGATION OPTION ANALYSES

Mitigation Option: Install Electric Compression with Grid Power

Description of Option
Under this option, existing or new natural gas fired internal combustion engines would be replaced with electric motors for powering compressors. Electric motors would be selected to deliver equal horsepower to that of the internal combustion engines being replaced.

Assumptions
It is assumed that electricity to power the electric motors would come from the existing electrical grid. The majority of the base load electricity in the region is produced from coal-fired electrical generation.

This option did not consider the installation of natural gas electrical generation systems, which would have entirely different emissions characteristics from coal-fired electrical generation. In this approach, small high-emission natural-gas engines would be replaced by electric motors driven by a larger low-emission natural-gas engine. Although natural gas fired generators have not been used in the region, the feasibility for possible future use should be investigated. [1]

In evaluating the changes in emissions for shifting from natural gas to electric (coal) powered compression, it is necessary to examine the emissions for each power source on an equivalent energy basis. Thus, for the same amount of energy consumption, the change in emissions from natural gas versus electricity must be considered.

In the evaluation of this mitigation option, it is not appropriate to consider emission modifications to existing electrical generating facilities. While such modifications may occur or new lower emitting facilities may be developed, the inclusion of such changes in emissions are speculative at this point in time. The emission data was developed using the EPA program EGRID. [2]

In this analysis, it was assumed that for visibility SO2 and NOx emissions are equivalent in terms of impacts because they cause approximately the same amount of visibility impairment. This is because the dry scattering coefficients for converting SO4 and NO3 concentrations into visual range are approximately equivalent. NOx emissions do participate in photochemical reactions that produce ozone.

However, ozone modeling analyses performed by the state of New Mexico as part of the Early Action Compact (EAC) and ozone monitoring data in the area suggest that ozone formation is VOC limited and consequently NOx emission reductions may cause increases in ozone concentrations. Both SO2 and NO2 ambient concentrations are in compliance with federal and state air quality standards.

As a first order approximation, 1 ton per year of SO2 emissions will result in the same amount of potential visibility impairment as 1 ton per year of NOx. In reality, because of the more complex and competitive reactions involving both SO4 and NO3, SO2 emissions may result in more visibility impairment than NOx emissions.

From an economic basis, conversion of natural gas-fired engines to electric compression is only practical for large engines and only in areas where electricity is already available within close proximity. This is because most locations do not currently have electrical power and it would not be cost effective to install power for small engines.[3]

In Colorado, most large engines (greater than 500 hp) are lean burn or have NSCR installed to reduce emissions (average emission factor for this size engine is 1.4 g/hp-hr). In addition, any new engines in this size category must achieve an emission limit of 1 g/hp-hr.[4] These engines are typically located at remote sites where power is not available.

In New Mexico, for large engines (greater than 500 hp) the average emission factor is 3.0 g/hp-hr. There are a total of 354 engines in this size category.[5] Of that total, 221 engines have NOx emission less than or equal to 1.5 g/hp-hr (62 percent), 108 engines have NOx emissions in the range of 1.6 to 5 g/hp-hr (31 percent) and 25 engines have NOx emissions greater than 5 g/hp-hr (7 percent). Under a recent BLM EIS Record of Decision (ROD), new engines must achieve 2 g/hp-hr.

<u>Method</u>

The energy consumption of a typical lean burn engine was calculated, converted into pounds per mega watt-hour and was compared to SO2 and NOx emissions from existing coal-fired power plants. This was done assuming an emission factor between 1 g/hp-hr and 5 g/hp-hr. It was then assumed that the computed emissions per mega watt of power represented emissions for 1-hour and were converted into tons per year by multiplying by 8760 hours per year and dividing by 2000 pounds per ton.

As indicated in Table 4, a shift from natural gas to electric (coal) for an engine of 1 MWhr capacity (approximately 1,342) hp with an emission factor of 1 g/hp-hr would result in an **increase** of 14 tons per year of SO2 + NOx. With engine emissions of approximately 2.0 g/hp-hr there is no net change in overall emissions by shifting from natural gas to electric. For all cases, the shift from natural gas to electricity results in higher greenhouse gas emissions.

<u>Conclusions</u>

NOx emissions from large engines in Colorado and the remaining engines in New Mexico are currently controlled at sufficient levels so that shifting from natural gas to electric compression may only result in a small reduction in emissions and in many cases would result in an increase in SO2 and NOx emissions.

For all categories of engines, greenhouse emissions would increase by shifting compressors from natural gas to electric.

Table 4: Change in SO2, NOx and Greenhouse Gas Emissions by Shifting from Natural Gas Compression to Electricity

Four Corners Grid Average Emissions lbs/MWh		tons/MWh/yr
SO2	2.65	11.6
NOx	3.64	15.9
NOx + SO2	6.29	27.6
CO2	1,989	8711.8

Table 4A: Example Engine Changes

Caterpillar 3608 LE Average Emissions lbs/MWh (equivalent)		Other Emission Rates (gr/hp-hr)				
SO2	0	0	0	0	0	0
Hp/kw-hr	1.342	1.342	1.342	1.342	1.342	1.342
Hp/mw-hr	1,342	1,342	1,342	1,342	1,342	1,342
Cubic feet gas/mw-hr	9,815	9,815	9,815	9,815	9,815	9,815
NOx Emission Rate gr/hp-hr	1	2	3	4	5	16
SO2 lbs/mw-hr	0	0	0	0	0	0
NOx lbs/mw-hr	3.0	5.9	8.9	11.8	14.8	47.3
CO2 lbs/mw-hr	1,138	1,138	1,138	1,138	1,138	1,138
SO2 tons/MWh/yr	0.0	0.0	0.0	0.0	0.0	0.0
NOx tons/MWh/yr	13.0	25.9	38.9	51.8	64.8	207.4
CO2 tons/MWh/yr	4985	4985	4985	4985	4985	4985
Delta SO2 tons/Mwh/yr	11.6	11.6	11.6	11.6	11.6	11.6
Delta NOx tons/Mwh/yr	3.0	-10.0	-22.9	-35.9	-48.9	-191.4
Delta NOx +SO2 tons/MWh/yr	14.6	1.6	-11.3	-24.3	-37.3	-179.8
Delta CO2 tons/Mwh/yr	3727	3727	3727	3727	3727	3727
Cat. 3608 Assumptions: 9815 Btu/kw-hr "Sweet" Natural Gas NOx - 1 gr/hp-hr 1 cu ft gas = 1,000 btu						

Endnotes:

1 Factors that need to be considered for use of a natural gas fired electrical generation system are: engines must be located in clusters that lend themselves to being interconnected by power lines; generator and line reliability need to be evaluated; the efficiency of electrical generators systems compared to natural gas fired compression must be evaluated; it needs to be determined if natural gas fired electrical

generators have substantially lower emissions than new natural gas fired compressor engines; cost and the benefits of this analysis need to be evaluated in terms of potential ambient air quality benefits, not simply emission reductions.

[2] EPA EGRID Program http://www.epa.gov/cleanenergy/egrid/index.htm

[3] The quantification of changes in emissions of this option does not address the cost of implementation or the reliability of the electrical grid. These issues must be considered if this option is deemed beneficial from an environmental perspective.

[4] Northern San Juan EIS Record of Decision (April 2007)

[5] NMED Part 70 permits, Minor source permits and Environ inventory.

Mitigation Option Analyses: Replace RICE Engines with Electric Motors for Selected Oil and Gas Operations (Alternative 2 – Power Source: On-Site Natural Gas-Fired Generators)

Description of Analysis of the Alternative Option

As an alternative to grid power, dedicated on-site, natural gas-fired, electrical generators can be used to supply power to electric motors suitable for selected replacement of "dirty" compression and other E&P RICE engines. This alternative to the Install Electric Compression (Grid Power Alternative) expands candidate engines for replacement beyond compressor engines since some existing compressor engines, particularly in the Northern San Juan Basin, are already well controlled. The electric motors are rated on an equivalent horsepower basis to RICE engines targeted for replacement. This analysis covers both the top 25 "dirtiest" and all essentially uncontrolled, primarily small, rich burn engines, with emissions greater than 4 g/hp-hr. Net NOx and CO emission reductions are reported in mass emission rates (tons/yr) and normalized mass emission rates (tons/yr/MW).

Assumption

The currently available gas electric generators run on variety of fuels including low fuel landfill gas or bio-gas, pipeline natural gas and field gas. The gas electric generators are available in the power rating from 11 kW to 4,900 kW. The calculated net reduction in emissions from existing RICE engines to electric motors powered by on-site electric generators were done based on an equivalent power basis.

In order to implement this option an electrical infrastructure would need to be constructed between the locations of the gas fired generator and the electric compressors. In addition, a control system would have to be developed so that as the engine load (demand) varies the generator supply would be adjusted to meet the demand. In order to implement this option it may be necessary to connect the generator to the power grid so that excess electricity could be utilized. Several engine companies manufacture gas electric generators. We assumed use of a mid-size Caterpillar gas electric generator as the reference natural gas on-site generator for calculating the net emissions for this alternative (not to be construed as an endorsement). The Caterpillar G3612 gas electric generator with power rating of 2275 kW emits 0.7 gram/hp-hr NOx and 2.5 g/hp-hr CO. It is important to note that the emissions from such generators are not different than what can be achieved from a lean burn engine (available with a capacity in excess of 500 hp) and not appreciable different emissions from new NSPS engines.(2 g/hp-hr vs 0.75g/hp-hr).

The selection of RICE engines for electrification analysis did not consider important factors that would need to be weighed in determining the degree of implementation that might be feasible. This would include the locations and spatial distribution of engines (e.g., proximity of with each other), the number and cost of required on-site generators, maximum transmission line lengths and any ROW issues, number of electric motors and costs, and operational and environmental factors.

Available engine inventories, for producers in New Mexico and Colorado (e.g., bp) were combined in order to obtain a representative engine inventory for the San Juan Basin.

Method

The NOx and CO emission of the reference Caterpillar G3612 generator were given in g/hp-hr which was converted into lbs/MW-hr by multiplying the (1,342 hp/MW) and divided by (454 gm/lbs). Further, the NOx and CO emissions in tons/yr/MW units were obtained by multiplying 8760 hrs/yr and dividing by 2000 lbs/ton. The NOx and CO emission factors and calculated normalized emission rates for NG generator are given in Table 5.

Table 5: Gas Electric Generator Emissions

2,275 kW			
	(g/hp-hr)	(lbs/MWh)	(tons/yr/MW)
NOx	0.70	2.07	9.06
CO	2.50	7.39	32.37

The net emission reduction was first calculated for the replacement the 25 worst NOx emitters and compared with a greater subset of replaced engines (e.g., engines emitting more than 4 g/hp-hr engines). The selection of the 25 worst engines is based on potential tons/yr NOx emission of individual engines. The potential engine emission calculation assumes 100% load and 8760 hrs operation per year. Engine emission factors were obtained by combining the New Mexico and Colorado engine inventory database used the Alternative 1 analysis.

The following illustrates how the mass emission rates (ER) and normalized mass emission rates (NER) were calculated for each engine size group.

EF (24.6 g/hp-hr) * Engine Size (1,350 hp) * (# of engines) * (8,760 hrs/yr) * (1/454g/lbs) * (1/2,000 lbs/ton) = 320.4 (tons/yr)

EF (24.6 g/hp-hr) * (1,342 hp/MW) * (8,760 hrs/yr)*(1/454g/lbs)*(1/2,000 lbs/ton) = 318.5 (tons/yr/MW)

The 25 engines with the highest mass emission rates in the combined inventory were identified. The total power of these was obtained by adding the rated power of individual engines, which was used to calculate equivalent emission from gas generator needed to run the 25 electric motors replacing the replaced RICE engines. For the case of the 25 highest emitting engines, the average capacity is 684 hp, the maximum capacity is 2,400 hp and the lowest capacity is 325 hp. What is important about the capacities is that for the majority of these engines lean burn engines are available. Table 6 shows the normalized average emissions in tons/yr/MW as well as net potential mass emission reductions for both NOx and CO emission based on the 25 worst NOx emitters. The average emission factor for the top 25 engines is 23.9 g/hp-hr.

Table 6: Emission change if 25 worst NOx emitting engines retired

Total rated power = 17,108 hp = 12.8 MW		
	NOx	
	Avg. NER (tons/yr/MW)	Total ER (tons/yr)
Caterpillar G3612	+9.06	+115.51
Worst 25 Engines	-251.21	-3,106.40
Net Reduction	-242.14	-2,990.89

Table 7 shows the same calculations based on all the engines emitting more than 9 g/hp-hr.

Table 7: Emission change if all engines emitting > 4g/hp-hr NOx retired

2925 engines with total rated power = 233,278 hp = 205.7 MW Emitting > 9 g/hp-hr NOx		
	NOx	
	avg/engine (tons/yr/MW)	Total (tons/yr)
Caterpillar G3612	9.06	1,863.75
All engines emitting more than 4.0g/hp-hr	211.36	40,562.21
Net Reduction	-202.30	-38,698.45

Conclusion

A net reduction of approximately 2,991 tons/yr of NOx can be achieved if the 25 engines with the highest NOx mass emission rate t operating in the San Juan Basin are replaced with nine 2 MW well controlled on-site natural gas electrical generators. Although most large RICE engines operating in the San Juan Basin are relatively small emitters individually and collectively, a significant number of small and medium range engines are not controlled well and collectively represent a relatively large E &P emission source group. The analysis in this alternative reveals a potentially significant emission reductions are possible for this group of engines. The calculation of emission reduction for replacing all the engines emitting more than 9.0 g/hp-hr NOx (over 2925 engines) with electric motors powered by several similar natural gas generators show that 38,698 tons/ per year of NOx reduction might be achieved by this option. This level of replacement would require approximately 90 on-site generators rated at 2 MW.

The potential emission reductions presented in this analysis assume optimal mitigation option implementation conditions which may not be nearly as optimistic if more detailed data were available and factored into the analysis. The selection of engines for electrification analysis did not consider important factors that would need to be weighed in determining the option feasibility and what degree of implementation would be possible. Factors such as the locations and spatial distribution of engines and operational and environmental issues would need to be considered. These and other factors would need to be carefully evaluated to better quantify the effectiveness of this alternative in terms of potential emission reductions achievable and certainly in quantifying implementation costs.

References

1. The emission and power information for the Caterpillar G3612 Gas Generator was obtained from Caterpillar's website. www.cat.com.

2. The engine inventory for NM and CO used to calculate emission reduction was provided by BP America, which includes contributions from: BP, New Mexico Environment Department, Colorado Dept. of Public Health & Environment and ENVIRON

Mitigation Option: Use of NSCR for NOx Control on Rich Burn Engines

Description of the Option

NO_X, CO, HC, and formaldehyde emissions from a stoichiometric engine can be reduced by chemically converting these pollutants into nitrogen, carbon dioxide and water vapor. The most common method for achieving this is through the use of a catalytic converter. In a catalytic converter, the catalyst will either oxidize (oxidation catalyst) a CO or fuel molecule or reduce (reduction catalyst) a NO_X molecule.

A process which causes reaction of several pollutant components is referred to as a Non Selective Catalyst Reduction (NSCR) and is applicable only to stoichiometric engines. Engines must operate in a very narrow air/fuel ratio (AFR) operating range in order to maintain the catalyst efficiency. Maintaining low emissions in a stoichiometric combustion engine using exhaust gas treatment requires a very closely regulated air/fuel ratio. Without an AFR controller, emission reduction efficiencies will vary. Most AFR controllers utilize closed loop control based on the readings of an exhaust gas oxygen sensor to determine the air/fuel ratio.

An AFR controller will only maintain an operator determined set point. For this set point to be at the lowest possible emission setting, an exhaust gas analyzer must be utilized and frequently checked.

Some issues associated with current practice NSCR retrofits on existing small engines operating at reduced loads are:

- a problem maintaining sufficient flue gas inlet temperature for correct oxygen sensor operation and the resulting effectiveness of the catalysts
- On engines with carburetors, there is difficulty maintaining the AFR at a proper setting
- On older engines, the linkage and fuel control may not provide an accurate enough air/ fuel mixture
- If the AFR drifts low (i.e., richer), ammonia formation will increase in proportion to the NOx reduction but not necessarily in equal amounts.

The first issue can be mitigated by retarding the ignition timing when the engine operates at reduced loads. The retarded ignition timing reduces NOx emissions and also raises the flue inlet temperature which helps maintain the catalyst efficiency. Eliminating or mitigating the second, third, and fourth issues require a closed-loop feedback control with an exhaust oxygen sensor to continuously adjust the AFR. One way of doing this is to adjust the carburetor so it operates slightly lean and use the feedback control to adjust the amount of supplemental fuel supplied to a port downstream of the carburetor. Worn carburetors and linkages should be replaced as a maintenance issue.

Assumptions

Currently, recent EIS RODs in Colorado and New Mexico require performance standards for new or replacement engines that will accelerate the implementation of the 2008 and 2010 federal NSPS for non road engines. Most engines in the 4 Corners Region in excess of 500 hp are lean burn engines and that trend is expected to continue in the future. These engines meet low emission standards through lean burn combustion technology and NSCR catalyst cannot be installed on this type of source. Therefore, the implementation of NSCR technology would have little or no effect on emission levels for new or replacement engines in excess of 500 hp. New or replacement engines having capacities of less than 500 hp and 300 hp will be required to meet an emission limit of 2 g/hp-hr in Colorado and New Mexico, respectively. Because of the limited availability of lean burn engines in this size range, NSCR will have to be used to achieve the prescribed emission levels. Thus, it is very likely that new or replacement engines will use this technology and there will be no additional possible NOx emissions reductions. It is important to note that a properly designed and operated NSCR system can achieve emission levels less than 2 g/hp-hr. However, the question becomes one of maintaining emissions at lower levels on a continuous basis and the operator's need to have a safety factor for ensuring continuous compliance with source emission limits. Thus, on average, actual emissions will be less than the prescribed regulatory limits, however, there will be times when emissions will approach the regulatory limit.

In examining additional NOx mitigation (beyond current regulatory drivers), NSCR would be applicable to existing rich burn engines that have a capacity of less than 500 hp.

In order for NSCR technology to result in any reduction of NOx emissions in the 4 Corners Region, it would have to be implemented on existing engines less than 500 hp. Estimates of potential emission reductions were calculated for engines in the range of 300 to 500 hp, 100 to 300 hp and between 75 hp and100 hp. Currently, there is no single retrofit kit that can be installed on existing engines. Even if an air fuel ratio controller with an oxygen sensor were installed, it is uncertain if the carburetor linkage would allow an accurate and precise enough control required to maintain the proper air fuel mixture without repair or upgrade.

However, compliance data (unannounced tests) obtained from the SCAQMD for 215 retrofitted rich burn engines show that over 90% of these engines, with installed AFRC, were able to meet or do better than 2 g/hp-hr. Six engines were essentially uncontrolled due to lack of any installed AFRC. Over 77% of the tested engines did better than 1 g/hp-hr (SCAQMD, 2007).

Engine Size >300 hp and < 500 hp

The uncontrolled NOx emission factor for existing rich burn engines between 300 hp to 500 hp in Colorado and New Mexico ranges from 11.4 to 21 g/hp-hr. The average emissions from the 11 rich burn engines in this size group are 18.3 g/hp-hr. The mass emission rate of a combined 3,660 hp for these engines total nearly 650 tons NOx/yr. Many of the engines in the 300-500 hp range already had some emission controls on them (such as being lean burn).

In new applications, laboratory data shows that NSCR can exceed 90% NOx reduction and in some cases possibly 95%. Because mitigation is being considered on a fleet of older existing engines, it may not be possible to achieve a 90% plus level of performance reliably in the field. Field tests to address this and other issues are being planned by Kansas State and are expected to start soon. Based on what we know now, lab data and existing compliance data from an inventory of over 200 retrofitted operating engines in southern CA., it was assumed that a well designed NSCR retrofit kit could reliably achieve NOx reduction in the range of 70% to 90%, Applying NSCR retrofits on the identified 11 "dirty engines" could reduce the NOx emissions to 1.8 tg/hp-hr (an ~ 450 tons/yr reduction) at the low end and 5.5 g/hp-hr at the high end (an ~ 590 ton/y reduction).

Engine Size > 100 hp < 300 hp

The uncontrolled NOx emission factor for existing rich burn engines between 100 hp to 300 hp in Colorado and New Mexico ranges from 15 to 24 g/hp-hr. The average emissions from the 240 rich burn engines in this size group are 19.1 g/hp-hr. The mass emission rate of the combined 38,394 hp for these engines total over 7,000 tons NOx/yr. Some engines in this size range were excluded from this group because they were identified as lean burn

Based on what we know now, lab data and existing compliance data from an inventory of over 200 retrofitted operating engines in southern CA, it was assumed that a well designed NSCR retrofit kit could reliably achieve NOx reduction in the range of 70% to 90%, Applying NSCR retrofits on the 240 identified "dirty engines" could reduce the NOx emissions to 1.9 g/hp-hr (an ~ 6,500 tons/yr reduction) at the low end and 5.7 g/hp-hr at the high end (an ~ 5,000 ton/y reduction). Not all retrofits may be operationally practical or economically feasible.

Engine Size > 75 hp and < 100 hp
The uncontrolled NOx emission factor for existing rich burn engines between 75 hp to 100 hp in Colorado and New Mexico ranges from 9.4 to 22.4 g/hp-hr. The average emissions from the 901 rich burn engines in this size group are 19.7 g/hp-hr. The mass emission rate of the combined 84,307 hp for these engines total over 11,200 tons NOx/yr. The lowest emitters are a group of Ford engines that may have EGR, but the database does not specify whether they have EGR.

Based on what we know now, lab data and existing compliance data from an inventory of over 200 retrofitted operating engines in southern CA, it was assumed that a well designed NSCR retrofit kit could reliably achieve NOx reduction in the range of 70% to 90%, Applying NSCR retrofits on the 900 identified "dirty engines" could reduce the NOx emissions to 5.9 g/hp-hr (an ~ 11,200 tons/yr reduction) at the low end and 2.0 g/hp-hr at the high end (an ~ 14,400 ton/y reduction). Not all retrofits may be operationally practical or economically feasible.

There is considerable uncertainty in the NOx reduction in these engines, which tend to be older than the engines in other size ranges. Attention to worn linkages and carburetor parts as well as closed-loop AFR control is expected to be necessary if these engines are to achieve effective NOx reduction.

Additional long term testing of the use of NSCR on existing small engines must be performed prior to any large scale implementation of this option. Currently, testing is beginning that will address the field application of this technology for retrofit conditions on rich burn small engines..[1]

Method
A spreadsheet containing the combined engine inventories for Colorado and New Mexico was developed. For each of the three size ranges of interest, a new database was created in which engines outside the size range of interest were deleted. Each of the three newly created databases were further modified by deleting all engines that are identified by their model designation as "lean-burn" and by deleting all remaining engines whose NOx emissions are 5.0 g/hp-hr or less. The resulting three databases contain only rich-burn engines in the size ranges of interest. Overall NOx emissions were totaled for each of the three size ranges, and emissions reductions of 70% and 90% were applied. resulted in a reduction in NOx emissions of 723 tons per year (a 7 percent reduction of Colorado oil and gas emissions). The engines in the New Mexico inventory were treated similarly.

One important point is that the New Mexico inventory indicated that 1,024 engines were less than 40 hp, which is the proposed de minimus threshold in the NSPS. Under the proposed regulation, EPA concluded that control of this size engine is not appropriate or cost effective. In New Mexico this class of engines had emissions of 2,049 tons per year (i.e., each engine had emissions of approximately 2 tons per year).

Table 8 presents the projected changes in NOx emissions if NSCR were installed on existing engines in Colorado and New Mexico.

Table 8: Emission Reductions from implementing NSCR on Existing Rich Burn Engines in Colorado and New Mexico

Colorado and New Mexico, 70% Reduction - NSCR on all Existing Rich-Burn Engines

Engine Size	Reduction (%)	Average Mitigated Emission Factor (g/hp-hr)	Unmitigated Total (16-year 2018-year) Average NOx Emissions (t/yr)	NOx Reduction (t/yr)
< 500 hp Eng > 300 hp	70	5.5	3150	453
< 300 hp Eng > 100 hp	70	5.7	5948	4934
< 100 hp Eng > 75 hp	70	5.9	13317	11201
Total Reduction			**51783**	**16588**
Percent Reduction				**32**

Colorado and New Mexico, 90% Reduction – NSCR on all Existing Rich-Burn Engines

Engine Size	Reduction (%)	Mitigated Emission Factor (g/hp-hr)	Unmitigated Total (16-year 2018-year) Average NOx Emissions (t/yr)	NOx Reduction (t/yr)
< 500 hp Eng > 300 hp	90	1.8	3150	582
< 300 hp Eng > 100 hp	90	1.9	5948	6343
< 100 hp Eng > 75 hp	90	2.0	13317	14402
Total Reduction			**51783**	**21327**
Percent Reduction				**41**

Conclusions

Installing NSCR on existing engines less than 500 hp in Colorado and New Mexico would result in a reduction of approximately 16,588–21,327 tons per year of NOx over current projected emissions in 2018.

Additional field testing on the installation of retrofit NSCR on engines less than 500 hp is needed to document what level of emission control could be achieved on a continuous basis.

Detailed modeling is planned that will quantify the air quality benefit of such reductions either separately or in combination with other potential mitigation measures. For visibility, currently in the Mesa Verde and Wimenuche Class I Areas NOx emissions are a very small portion of the total extinction budget, however in recent years the trend has been flat or showed slight increases. Also, because of complex photochemical reactions involving VOC emissions and NOx emissions, changes in NOx emissions could result in localized increases or decreases in ozone. Regional effects of changes in ozone precursor emissions would need to be determined using a photochemical model.

Mitigation Option: Use of SCR for NOx Control on Lean Burn Engines

Description of the Option

Using this option, existing or new lean burn natural gas fired internal combustion engines would be installed with selective catalytic reduction (SCR). This technology uses excess oxygen in a selective catalytic reduction system. Reactant injection of industrial grade urea, anhydrous ammonia, or aqueous ammonia is required to facilitate the chemical conversion. A programmable logic controller (PLC) based control software for engine mapping/reactant injection requirements is used to control the SCR system. Sampling cells are used to determine the amount of ammonia injected which depends on the amount of NO measured downstream of the catalyst bed.

In the proposed standards for Stationary Spark Ignition Internal Combustion Engines, EPA states the following with respect to the installation of SCR on natural gas fired engines: "For SI lean burn engines, EPA considered SCR. The technology is effective in reducing NOx emissions as well as other pollutant emissions, if an oxidation catalyst is included. However, the technology has not been widely applied to stationary SI engines and has mostly been used with diesel engines and larger applications thousands of HP in size. This technology requires a significant understanding of its operation and maintenance requirements and is not a simple process to manage. Installation can be complex and requires experienced operators. Costs of SCR are high, and have been rejected by States for this reason. EPA does not believe that SCR is a reasonable option for stationary SI lean burn engines. Consequently, this technology is not readily applicable to unattended oil and gas operation that do not have electricity.[1] However, the technology has been used successfully on lean-burn engines to meet Southern California's stringent limit of 0.15 g/hp-hr. The SCAQMD's staff report supporting Rule 1110 identifies SCR as a RACT on lean burn engines capably of achieving over 80% NOx control. The staff report also notes that SCR is a relatively high cost control technology option for RICE engines. Reasons given include the "capital cost for the catalyst, the added cost and complexity of using ammonia, and the instrumentation and controls needed to carefully monitor NOx emissions and meter the proper amount of ammonia." However they also note that the estimated costs have been declining over the past several years and are currently estimated to range from $50 to $125 per horsepower.

Assumptions

There is very little information in the literature regarding the incremental NOx emission reduction of SCR beyond lean burn technology for remote unattended oil and gas operations because there have been very limited installations of this technology for oil and gas compressor engines. Table 9 presents a summary of incremental SCR emission reductions and cost effective control estimates for SCR on a lean burn engine.[2]

Table 9: Incremental SCR Emission Reductions and Cost Effective Control Estimates for SCR

Incremental Cost-Effectiveness Estimates for ICE			Control Techniques and Technologies	
			Incremental	**Incremental NO_X**
Engine Type	**Control Comparison**	**Horsepower**	**NO_X Reduction**	**Cost-Effectiveness**
			(tons/year)	**(\$/ton of NO_X Removed)**
Lean Burn				
	From Low-Emission Combustion to SCR (96%)	300-500	**3.3**	8,800
		500-1000	**6.6**	10,300

There are several concerns regarding this information. First, it is not known if the emission reductions are based on actual performance tests or theoretical emission calculations. It is also not known what the reference basis is for the emission reduction of 6.6 tons per year of NOx. Review of CARB databases regarding NOx engine emissions does not provide any data regarding actual installations of SCR on lean burn engines for oil and gas operations. There is some very limited performance testing on SCR with lean burn engines that operate on pipeline natural gas (as opposed to field gas) for cogeneration facilities. Such emission data for cogeneration facilities is not applicable to oil and gas compressor engines. This is because cogeneration facilities tend to operate at a continuous load and have personnel present to operate the equipment. The CARB databases also provide testing of oil and gas SCR for high emitting 2 cycle engines (removal rates in the range of approximately 50 to 85 percent). These installations are not comparable to adding SCR to a well controlled engine.

Because of the limited application data for SCR on natural gas fired engines for oil and gas operations it is difficult to estimate the amount of potential emission reduction that could be achieved through the implementation of this technology. In addition, it is not clear how well this technology would perform in unattended remote applications. The limited data that does exist suggests that there may only be a small incremental reduction in NOx emissions beyond lean burn technology and this reduction would result at a very high incremental cost. This technology should be considered an emerging technology and merits additional testing for this unique application.

Because of non-linear chemistry involved in photochemical reactions of ozone and secondary aerosols that result in a reduction of visibility, NOx emission reductions estimated in this analysis may or may not result in equal improvement in ambient air quality levels. Also, excess ammonia slip within the discharge plume of an engine may accelerate the conversion of NOx emissions into particulate nitrate.

Table 10 presents CARB budgetary costs for the installation of SCR on lean burn engines.

Table 10: Cost-Effectiveness Estimates for ICE Control Techniques and Technologies

Selective Catalytic Reduction for Lean Burn				
Horse Power Range	**Capital Cost (S)**	**Installation Cost(S)**	**O&M Cost (S/year)**	**Annualized Cost (S/year)**
301-500	43,000	17,000	35,000	36,000
501-1000	116,000	33,000	78,000	78,000
1001-1500	132,000	53,000	117,000	148,000
Average gt 500 hp	**124,000**	**43,000**	**97,500**	**113,000**

It should be noted that in a white paper prepared by Thomas P. Mark regarding control of Engines in Colorado that he estimates the annual operating cost of SCR on an engine having a capacity of 1000 hp is approximately $140,000 per year and is consistent with the CARB estimate.[3]

Conclusions

The installation of SCR beyond lean burn technology is not a proven or cost effective technology at the present time. With additional development and testing for oil and gas operations, it may become an effective control technology for tertiary control of lean burn engines.

Endnotes

1 Federal Register Monday, June 12, 2006 40 CFR Parts 69, 63, et al. Standards of Performance for Stationary Spark Ignition Internal Combustion Engines and National Emission Standards for Hazardous Air Pollutants for Reciprocating internal Combustion Engines; Proposed Rule

2 California Environmental Protection Agency Air Resources Board, 2001, “Determination of Reasonably Available Control Technology.

3 Thomas P. Mark, October 31, 2003, Control of Compressor Engine Emissions Related Costs and Considerations.

Mitigation Option: NSPS Regulations

Description of Option

EPA is in the process of developing the first national requirements for the control of criteria pollutants from stationary engines. Separate rulemakings are in process for compression-ignition (CI) and spark-ignition (SI) engines. These NSPS will serve as the national requirements, leaving states with the authority to regulate more stringently as might be required in unique situations.

CI NSPS: The final NSPS for stationary CI (diesel) engines was published in the Federal Register on July 11, 2006. It requires that new CI engines built from April 1, 2006, through December 31, 2006, for stationary use meet EPA's nonroad Tier 1 emission requirements. From January 1, 2007, all new CI engines built for stationary use must be certified to the prevailing nonroad standards. (Minor exceptions are beyond the scope of this discussion.)

SI NSPS: The NSPS proposal for stationary SI engines, including those operating on gaseous fuels, was published in the Federal Register on June 12, 2006. Per court order, the rule is to be finalized by December 20, 2007. Like the CI NSPS, certain elements of the SI NSPS will be retroactively effective once finalized. The following summarizes the proposed requirements:

New Source performance Standards (NSPS)

EPA SI NSPS NPRM

NOx/CO/NMHC (g/bhp-hr)		2007		[illegible]		[illegible]		[illegible]		2011	
		1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul	1-Jan	1-Jul
All engines	≤ 25 hp			40 CFR 90							
Gasoline & RB LPG	26-499 hp			40 CFR 1048							
	≥ 500 hp		40 CFR 1048								
Natural gas & LB LPG											
Non-emergency	26-499 hp			2.0/4.0/1.0						1.0/2.0/0.7	
	> 500 hp		2.0/4.0/1.0						1.0/2.0/0.7		
Emergency	> 25 hp					2.0/4.0/1.0					
Landfill / digester gas	< 500 hp			3.0/5.0/1.0						2.0/5.0/1.0	
	≥ 500 hp		3.0/5.0/1.0						2.0/5.0/1.0		

Notes: [illegible]
[illegible]
Emergency engines limited to 100 hours per year for maintenance and testing.

Since the proposed NSPS will become an EPA regulation, it will become the base case for emissions for new modified and reconstructed engines. As such, the benefits of this regulation are already incorporated into the Cumulative Effects emission inventories.

Mitigation Option: Optimization/Centralization

Description of Option

Under this option, natural gas fired internal combustion engines that are used to power various oil and gas related operations would be installed with appropriate sized engines (horsepower) for the activity being conducted. The advantage of this approach would be reducing the cumulative amount of horsepower deployed and might result in reducing emissions. This may also be accomplished by using larger central compression in lieu of deploying numerous smaller compressor engines at a number of individual locations such as well sites.

Assumptions

1) Current lease agreements for production cannot be easily changed.
2) Engine emission factors do not change with load.
3) Emission factors on small new, modified and reconstructed engines are consistent with large engines (proposed NSPS will require this).

Method

Short term emissions from compressor engines are based on the amount of fuel used which is a function of capacity (hp) and load. In determining annual emissions, the hours of operation are important. Assuming that emission factors do not change with load, as the load is reduced emissions will decrease. If it is assumed that all engines have the same rate of emissions, simply reducing the number of engines and operating them at higher capacity will likely result in the same amount of fuel usage and the same amount of emissions

Conclusions

Implementation of this option will not result in any quantifiable reduction in emissions.

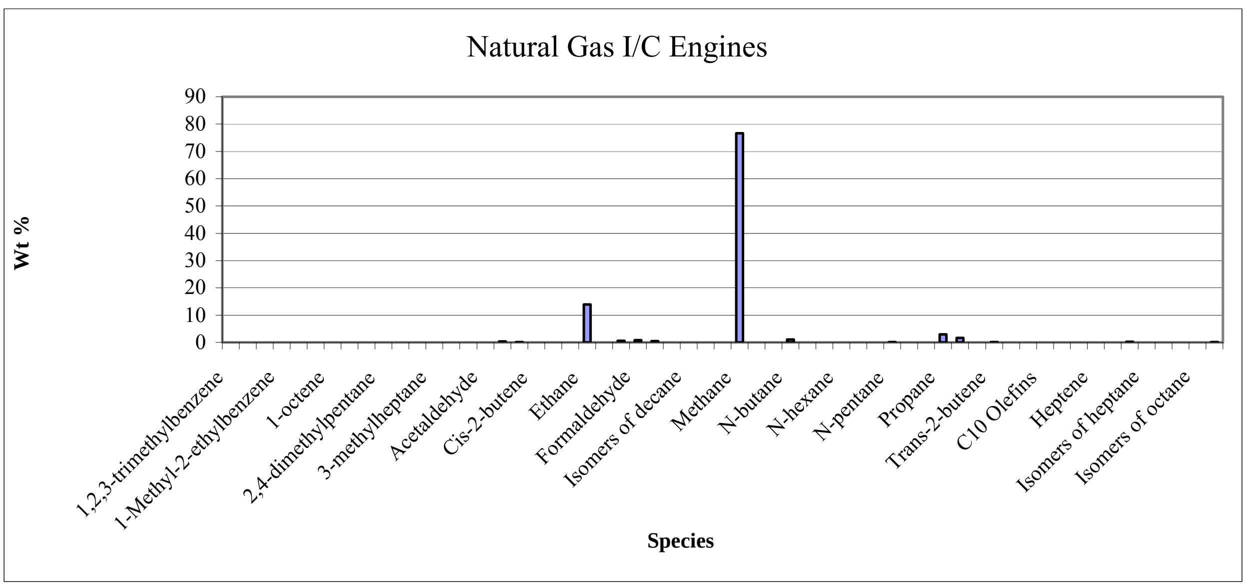
Mitigation Option: Use of Oxidation Catalyst for Formaldehyde and VOC Control on Lean Burn Engines

Description of Option
Using this option, existing or new lean burn natural gas fired internal combustion engines would be installed with oxidation catalyst to convert formaldehyde and VOC emissions to CO2. This technology requires the use of an air fuel ratio controller (AFR) in conjunction with the catalyst.

Assumptions
In developing emission inventories for the Four Corners Region, it was assumed that formaldehyde emissions from natural gas fired engines were 0.22 g/hp-hr for all types of engines. There is a large uncertainty in emission factors for formaldehyde which is why a conservative value of 0.22 g/hp-hr was assumed for all engines. In reality, lean burn engines have higher formaldehyde emissions than rich burn engines and therefore it is more appropriate to consider oxidation catalyst technology only for lean burn engines.

The emission inventory for VOC engines used manufacturers' emission factors. There is a large uncertainty if those emission factors represent total hydrocarbons (THC) or VOCs and also they do not include formaldehyde. THC includes methane (C1) and ethane (C2) which EPA does not regulate because they have low photochemical reactivity. The following figure presents the speciation of organics from natural gas fired engines from the EPA Speciate data base and indicates that the majority of the hydrocarbon emissions are methane and ethane. Thus, the projected reductions in hydrocarbon emissions may not affect ozone formation.

Composition of Hydrocarbon Emissions from Natural Gas Fired Engines

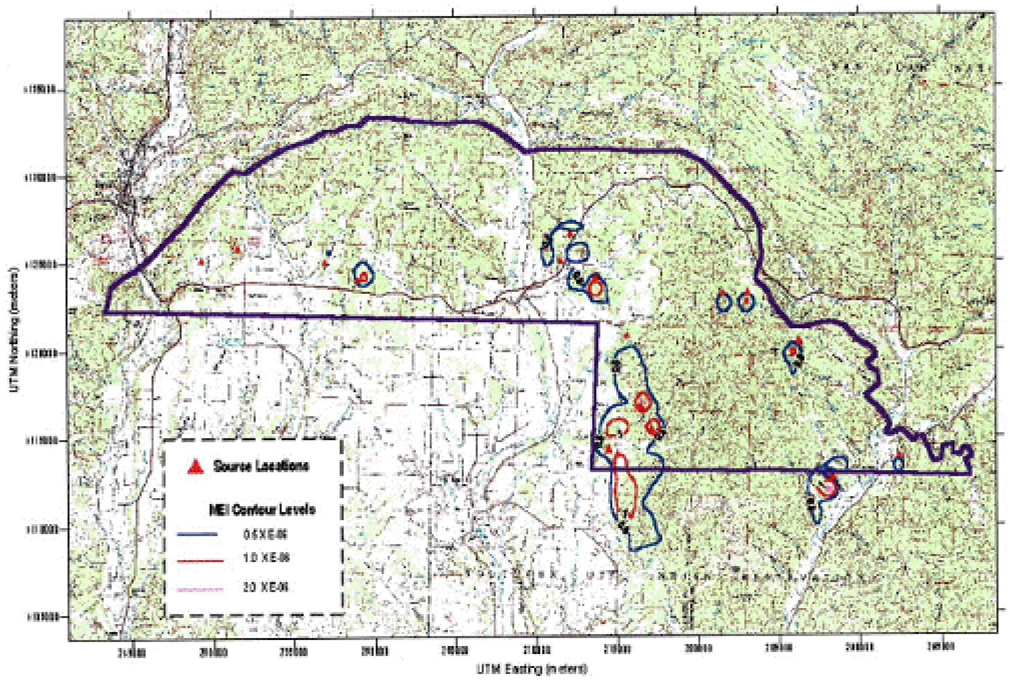


It was assumed that this technology could obtain a 90 percent reduction in hydrocarbons and 80 percent reduction in formaldehyde.

Previous modeling analyses of formaldehyde HAP impacts indicate that maximum impacts for the most likely exposed individual (MLE) are approximately 4x10-6 and have a very localized impact.[1,2] A plot indicating the formaldehyde impacts is presented in the following figure.[3]

Formaldehyde Isopleths from Northern San Juan EIS

Figure 7-5. HAP Incremental Risk Analysis for Formaldehyde MEI (Maximum Development)



Method
Table 11 presents the projected changes in formaldehyde and hydrocarbon emissions if oxidation catalyst were installed on new engines in Colorado and New Mexico.

Table 11: Estimated Changes in VOC and Formaldehyde Emissions with the Installation of Oxidation Catalyst

	VOC Reduction (t/yr)	Unmitigated VOC (t/yr)	Percent VOC Reduction	Formaldehyde Reduction (t/yr)	Unmitigated Formaldehyde (t/yr)	Percent Formaldehyde Reduction
Colorado	204	3115	7	42	471	9
New Mexico	1415	[Frame2] 42,117	3.4	382	365	40

In Colorado, the installation of oxidation catalyst on new engines greater than 300 hp[4] would result in formaldehyde emission reductions of 42 tons per year (a 9 percent reduction in emissions) in 2018. This option would also result in a reduction of 204 tons per year of VOC emissions (a 7 percent reduction in emissions) in 2018. In New Mexico, the installation of oxidation catalyst on new engines greater than 300 hp would result in formaldehyde emission reductions of 385 tons per year (a 40 percent reduction) in 2018. This option would result in a reduction of 1,415 tons per year of hydrocarbon emissions (primarily methane and ethane) and would correspond to a 3.4 percent reduction in total emissions in 2018.

Conclusions
Installing oxidation catalyst on new engines greater than 300 hp in Colorado would result in a reduction of approximately 42 tons per year of formaldehyde over current projected emissions in 2018. and 204 tons per year of VOCs (primarily methane and ethane).

Installing oxidation catalyst on new engines greater than 300 hp in New Mexico would result in a reduction of approximately 382 tons per year of formaldehyde and 1,415 tons per year of hydrocarbons (primarily methane and ethane) for new engines in 2018.

There is a large uncertainty in the VOC estimates because the emitted compounds may be methane and ethane which are not regulated VOCs.
Detailed modeling is necessary to determine the air quality benefit of such reductions with respect to VOCs.

Previous HAP modeling indicates that there are minimal and very localized HAP impacts from natural gas fired engines.

Endnotes
1 Dames and Moore 1999, "Southern Ute Environmental Impact Statement.
2 RTP Environmental, 2004, "Northern San Juan EIS 2002 Air Quality Impact Assessment Technical Support Document Northern San Juan Basin Coalbed Methane Environmental Impact Statement."
3 RTP Environmental, 2004, "Northern San Juan EIS 2002 Air Quality Impact Assessment Technical Support Document Northern San Juan Basin Coalbed Methane Environmental Impact Statement."
4 The lower size cutoff for current lean burn technology.

Mitigation Option: SNCR for Lean Burn Engines

<u>Description of the mitigation option</u>

SNCR stands for Selective Non-Catalytic Reduction. It is similar to Selective Catalytic Reduction (SCR), except that it lacks a catalyst. Like SCR, SNCR can be applied to lean-burn or diesel engines and urea or ammonia is injected into the exhaust manifold. Because it lacks a catalyst, SNCR has a lower conversion efficiency than SCR has.

Do not confuse SNCR with NSCR (Non-Selective Catalytic Reduction), which is applicable to rich-burn engines and uses a catalyst but does not use ammonia or urea as a reductant.

SNCR is used primarily for NOx reduction in boilers. It use in engines has been supplanted by SCR because it has a higher NOx reduction efficiency than SNCR.
SNCR at best can convert only about 60% of the NOx in the exhaust stream compared to about 90% for SCR. Like SCR, SNCR is subject to ammonia slippage.

Because of the low NOx removal rate, the uncertainty in application to natural gas fired engines and because more effective proven technologies exist, this option was not evaluated further.

Mitigation Option: Next Generation Stationary RICE Control Technologies

In evaluating the next generation RICE control technology, it is important to note that current engine technology has resulted in substantial NOx reductions in natural gas fired engines compared to engines that were installed 10 years ago. New large lean burn engines are achieving over 90 percent control reliably and cost effectively. In order for the next generation of controls to be implemented in the field they must achieve the same standards.

In the near term lean-burn technology could be applied to engines smaller than 500 hp. This is a decision to be made by the engine manufacturers with the driving force being emissions regulations. Alternatively, the engine manufacturers or after market control technology companies could partner with researchers at universities and/or national laboratories to test, verify and develop reliable rich burn engine non-selective catalytic reduction (NSCR) system retrofit kits (e.g., air/fuel ratio controllers, lambda sensors, TWC, ion sensors). A next generation NSCR system could include nitrogen injection to achieve higher levels of NOx control (> 95%). The NSCR for rich burn engines may be a very attractive option for the oil and gas industry and for control technology vendors since the technology is well developed and certified for automobile applications.

With that preface this analysis investigates the status of three new and/or evolving emissions-control technologies. They are: laser ignition, air-separation membranes, and lean-burn NOx catalyst (including NOx traps).

Laser ignition is under development in the laboratory, but it has not reached a point where technology transfer viability can be determined.

Air separation membranes have been demonstrated in the laboratory, but have not been commercially available because the membrane manufacturers do not have the production capacity for the heavy-duty trucking industry. Since stationary engines are a smaller market, there is a high probability that the membrane manufacturers could ramp up production in this area.

There are several variations of lean-burn NOx catalysts, but the one of most interest is the NOx trap. NOx traps are being used primarily in European on-road diesel engines, but are expected to become common in the U.S. as low-sulfur fuel becomes available. Applicability to lean-burn natural-gas engines is possible but it will require a fuel reformer to make use of the natural gas as a reductant.

I. Laser Ignition

Description of the Mitigation Option

Laser ignition replaces the conventional spark plugs with a laser beam that is focused to a point in the combustion chamber. There, the focused, coherent light ionizes the fuel-air mixture to initiate combustion. Applicability is primarily to lean burn engines, although laser ignition could be applied to rich burn engines. Air at high pressure is a good electrical insulator that requires high voltage to overcome. This limits the turbocharging pressure and compression ratio because the insulation on spark-plug wires breaks down at high voltage. Laser ignition is not subject to the same limitation, so a lean-burn engine with laser ignition can have a higher turbocharging pressure and a higher compression ratio than one with spark plugs.

Advantages of laser ignition compared to spark plugs include: 1. Longer intervals between shutdowns for maintenance because wear of the electrodes is eliminated, 2. More consistent ignition with less misfiring because higher energy is imparted to the ignition kernel, 3. The ability to operate at leaner air-fuel mixtures because higher energy is imparted to the ignition kernel, 4. The ability to operate at higher turbocharger pressure ratio or compression ratio because the laser is not subject to the insulating effect of high-pressure air, and, 5. Greater freedom of combustion chamber design because the laser can be focused at the geometric center of the combustion chamber, whereas the spark plug generally ignites the mixture near the boundary of the combustion chamber.

However, laser ignition has some unresolved research issues that must be resolved before it can become commercially available. These include: 1. Lasers are intolerant of vibration that is found in the engine's environment. 2. Some means of transmitting the laser light to each combustion chamber should be developed while accommodating relative motion between the engine and the laser. This might be done with mirrors or with fiber optics. Fiber optics generally lead to a simpler solution to the problem. 3. Current fiber optics is limited in the energy flux they can transmit. This leads to a less-than-optimum energy density at the focal point. 4. Wear of the fiber optic due to vibration may limit its lifetime. 5. The cost of a laser is such that multiple lasers per engine are too expensive. Therefore, a means of distributing the light beam with the correct timing to each cylinder must be developed.

Although laser ignition could be applied to rich burn engines, environmental benefits would accrue to lean burn engines. Laser ignition may be able to reduce NOx emissions by as much as 70% compared to spark-ignited engines.[1] However, in the reference cited, the baseline emissions for the engine with spark ignition were higher than the emissions that are currently achievable with lean burn engines. The more consistent ignition compared to spark ignition can be expected to decrease emissions of unburned hydrocarbons. The ability to operate at leaner air-fuel ratios and at higher turbocharging pressure are responsible for the decrease of NOx emissions because of lower combustion temperatures. Laser ignition systems have not been developed to the point where the effect of improved combustion chamber design can be measured. It is reasonable to expect that a better combustion chamber design would further decrease emissions of unburned hydrocarbons, carbon monoxide, and NOx. In actual operation of the engine, misfiring of one or more cylinders contributes to loss in efficiency and increase in emissions. With the laser ignition system, misfiring can be significantly reduced. Whether laser ignition combined with lean-burn engine technology can meet the Southern California NOx limit of 0.15 g/hp-hr will be the subject of further research.

One of the advantages of laser ignition is its potential to eliminate downtime due to the need to change spark plugs. This advantage would accrue to both rich burn engines and lean burn engines. Higher efficiency due to near elimination of cylinder misfirings is an additional benefit.

Laser ignition would compete with selective catalytic reduction (SCR) applied to lean-burn engines. Although costs are unknown at this time, laser ignition is likely to be the lower cost alternative.

A tradeoff for engine manufacturers, assuming that laser ignition can be developed to the point of commercial feasibility, is whether or not to develop retrofit kits. Retrofits would be expected to take away sales of new engines.

A tradeoff for engine users is whether to continue using spark ignition or to purchase a laser ignition that is initially more expensive but has a future economic benefit.

Another tradeoff for engine users is whether to retrofit laser ignition to an existing engine or to spend more money for a new engine in return for future benefits.

Assumptions

In the analysis, it is assumed that the limitations of laser ignition described above can be overcome through research and development. It is further assumed that NOx emissions can be reduced by 70% compared to spark-ignition lean-burn engines. Until more research is done, the 70% reduction is most likely an upper limit. This reduction is due to the ability to operate at higher turbocharging pressure, hence leaner air/fuel ratios and lower combustion temperature than is currently possible with spark-ignition engines. Since lean-burn engines are primarily those over 500 hp, the technology is assumed to apply only to engines larger than 500 hp. The technology is assumed to be retrofitable to any engine that uses 18-mm spark plugs, so it is applied to all engines, new and existing, in the Colorado and New Mexico databases.

Conclusions

Testing in the laboratory has shown potential emissions reductions in the 30% to 60% range, which may or may not be achievable when this technology is implemented in the field.

II. Air-Separation Membranes

Description of the Mitigation Option

The purpose of air-separation membranes is to change the proportion of nitrogen to oxygen in air. A membrane can be optimized to either enrich the oxygen content or to enrich the nitrogen content. Both the oxygen enrichment mode and the nitrogen enrichment mode have been tested in the laboratory with diesel engines. The nitrogen enrichment mode has been tested in the laboratory with Natural Gas Fuel as well. The oxygen enrichment mode and the nitrogen enrichment mode are mutually exclusive.

Oxygen enrichment produces a dramatic reduction in particulate emissions in diesel engines at the expense of increased NOx emissions. However, Poola[2] has shown that the effects are non linear such that a small enrichment (1 percentage point or less) produces a significant reduction in particulate emissions with only a small increase in NOx emissions. By retarding the injection timing, one can achieve a reduction in both NOx and particulate emissions. The overall benefits of oxygen enrichment are relatively small and have not been tested with natural gas-fueled engines, so it will not be considered further.

Nitrogen enrichment produces the same effect on emissions as exhaust-gas recirculation; NOx decreases. It can be applies to either diesel or rich-burn natural-gas engines. Unlike exhaust-gas recirculation (EGR), nitrogen-enriched air contains only the components of pure air. Manufacturers of both diesel and natural-gas engines are concerned that components of exhaust gas could shorten the life of the engines with EGR. In the case of diesel engines, it is clear that exhaust particulate matter could cause wear between the piston rings and cylinder liners. Even in the case of rich-burn engines, the exhaust gas contains condensed liquids that may cause wear. As recently as August, 2004, the Engine Manufacturers Association does not consider EGA to be a viable option for rich-burn engines.[3] Thus, nitrogen enriched air is seen as an alternative to EGR because it contains no components that are not found in air. Published data from tests in natural-gas engines show engine-out NOx reductions of 70% are possible with nitrogen-enriched combustion air. [4] When combined with non-selective catalytic reduction (NSCR), the overall NOx reduction can reliably exceed 90%.

The cost of nitrogen-enriched air systems are expected to be higher than that of EGR. However, nitrogen-enriched air does not have components that can cause increased engine wear as EGR does.

Assumptions

Only nitrogen-enriched air is considered in this analysis. The technology is assumed to be retrofittable to all rich-burn engines, new and existing. While nitrogen-enriched air can be combined with non-selective catalytic reduction (NSCR), only the effects of nitrogen-enriched air are considered here. The effect is assumed to be the same as that of EGR; it can produce a 70% reduction in NOx emissions. This is most likely an upper limit.

Conclusions

Testing in the laboratory has shown potential emissions reductions in the 50% to 90% range, which may or may not be achievable when this technology is implemented in the field. The upper end assumes integration as a component of a reasonably well-designed (use of current state of the art air fuel ratio controllers / sensor technologies) NSCR system.

III. Lean-Burn NOx Catalyst, Including NOx Trap

Description of the Mitigation Option

Lean-burn NOx catalysts have been under development for at least two decades in the laboratory with the intent of producing a lower cost alternative to SCR. They do not have the ammonia slip problem associated with SCR, but they typically use some of the fuel as a reductant.

Several variants of lean-burn NOx catalysts have been studied: (1) Passive lean-burn NOx catalysts simply pass the exhaust over a catalyst. The difficulty has been low NOx conversion efficiency because the oxygen content of a lean-burn exhaust works against chemical reduction of NOx. Conversion efficiencies of the order of 10% are typical.[5]

(2) Active lean-burn NOx catalysts use a fuel as a reductant. The catalyst decomposes the fuel, and the resulting fuel fragments either react with the NOx or oxidize. Methane is much more difficult to decompose than heavier fuels, such as diesel [aardahl.pdf. A wide range of NOx reduction efficiencies from 40% to more than 80% have been published. [6,7] Variants of active lean-burn catalyst systems may use plasma or a fuel reformer to produce a more effective reductant than neat fuel.[8,9,10]

(3) NOx trap catalysts are a more recent development that has seen some laboratory success. Operation is a two-step cyclic process. In the first stage the NOx trap adsorbs NOx while the engine operates in a lean-burn mode. In the second stage, the engine operates with excess fuel in the exhaust. The fuel decomposes on the catalyst and reduces the NOx to molecular nitrogen and water. With natural gas as the fuel, a fuel reformer is necessary to break up the extremely stable methane molecule for use as a reductant When the supply of trapped NOx is exhausted, the system reverts back to first-stage operation. NOx reduction efficiencies in excess of 90% have been published.[11] A sophisticated engine control is required to make this system work.

NOx traps have been proven to be effective and have seen some limited commercial success in Europe. NOx traps are one of the reasons for the dramatic reduction in sulfur content of diesel fuel in the U.S. Fuel-borne sulfur causes permanent poisoning of NOx-trap catalysts. There are doubts regarding the NOx conversion efficiency levels after 1,000 hours or longer use. This should be evaluated, as well as the durability of the equipment.

Active lean-NOx catalysts have seen limited commercial success because they are less effective than NOx traps and are not being considered for on-road diesel engines. Some instances of formation of nitrous oxide (N2O) rather than complete reduction of NOx have been reported.

Passive Lean-NOx catalysts do not provide enough NOx reduction to be considered viable.

Costs of retrofitting a lean-burn NOx catalyst are estimated at $6,500 to $10,000 per engine [retropotentialtech.htm.][11] $15,000-$20,000 including a diesel particulate filter [V2-S4_Final_11-18-05.pdf] for off-road trucks.[12] Estimates are $10-$20/BHP for stationary engines [icengine.pdf]. [14]

Little information on the cost of NOx-trap catalytic systems was found. The overall complexity of a NOx-trap system is only slightly more than that of a lean-burn NOx catalyst, so costs can be expected to be slightly higher. With methane-burning engines, both active lean-burn NOx catalysts and NOx-trap catalysts require a fuel reformer or other means of dissociating methane. This will add an increment of cost.

Both active lean-NOx technology and NOx-trap technology impose a fuel penalty of 3-7%.

Assumptions

Only NOx-trap catalysts, which can remove up to 90% of the NOx in the exhaust stream are considered for this analysis. The technology is applicable to lean-burn engines, which are considered to be those having more than 500 hp in the Colorado and New Mexico databases. The technology is assumed to be retrofitable, so it is applied to all new and existing engines greater than 500 hp.

Conclusions

Testing in the laboratory has shown potential emissions reductions in the 40% to 70% range, which may or may not be achievable when this technology is implemented in the field.

Summary

Three technologies are reported: laser ignition, air-separation membranes, and lean-burn NOx catalyst.

Laser ignition is not presently a commercial product. The impetus for investigating it is the potential to eliminate the need for changing spark plugs. It will also allow operation at leaner air-fuel ratios, higher compression ratios, and higher turbocharging pressure. Leaner air-fuel ratios imply lower engine-out NOx emissions so the after treatment can be smaller or can give lower overall emissions. Higher compression ratios and turbocharging ratios imply higher engine efficiency.

Air-separation membranes used to deplete oxygen from the combustion air can serve as a clean replacement for EGR. That is, an engine using oxygen-depleted air would not be ingesting combustion products. Engine manufacturers are concerned that EGR will shorten the life of their engines and lead to premature overhauls and warranty repairs. The technology has been demonstrated in the laboratory, but has not been used for heavy-duty trucks because membrane manufacturers do not have enough production capacity for the market. Stationary engines are a smaller market, so the membrane manufacturers may be able to ramp up their capacity with stationary engines. Applicability is to diesel engines and rich-burn natural-gas engines. Oxygen-depletion membranes are not applicable to lean-burn natural-gas engines.

Lean-burn NOx catalysts have several forms, but the one that is of most interest is the NOx-trap catalyst. Unlike SCR, lean-burn NOx catalysts use the engine's fuel as a reductant and do not require a separate supply of reductant. It is a well proven in the laboratory and is commercially available in Europe for diesel engines, but it requires a fuel reformer if natural gas is used as the reductant. A sophisticated control system is required to cycle the engine between its two modes of operation. Ammonia slippage is not an issue with NOx traps, and if there is any slippage of unburned fuel it can be removed with an oxidation catalyst. Cost is high but less than that of SCR systems. A large part of the cost of SCR is the ammonia or urea reductant necessary to make it work. A disadvantage of NOx traps is that they are intolerant of fuel-borne sulfur. For diesel fuel, the sulfur content must be less than 15 ppm. Fuel-borne sulfur permanently poisons the catalyst. Since fuel is used as a reductant, there is a fuel consumption penalty of 3-7%.

Endnotes

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2 R.B. Poola and R. Sekar, “Reduction of NOx and Particulate Emissions by Using Oxygen-Enriched Combustion Air in a Locomotive Diesel Engine,” Transactions of the ASMR, Vol. 125, p524ff, April., 2003.

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4 Munidhar S. Biruduganti, Sreenth B. Gpupta, Steven McConnell, and Raj Sekar, “Nitrogen Enriched Combustion of a Natural Gas Engine to Reduce NOx Emissions,” paper number ICEF2004-843 in Proceedings of the ASMR ICE 2004 Fall Technical Conference, Oct. 24-27, 2004, Long Beach, CA.

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[6] Park, op cit.

[7] 'Emission Control Technology for Stationary Internal Combustion Engines, Status Report," Manufacturers of Emission Controls Association, 1660 L St. NW, Washington, DC, July 1997.

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[9] C. Aardahl and P. Park, "Heavy-Duty NOx Emissions Control: Reformaer Assisted vs. Plasma-Facilitated Lean NOx Catalysis," DEER Conference, Newport, RI, August, 2003.

[10] Magdi K. Khair, partha P. Paul, and Michal G. Grothaus, "Synergistic Approach to Reduce Nitrogen Oxides and Particulate Emissions from Diesel Engines, 08-9051," Southwest Research Institue, 1999.

[11] James E. Parks II, H. Douglas Ferguson III, and John M.E. Storey, "NOx reduction with Natrual Gas for Lean Large-Bore Engine Applications Using Lean NOx Trap Aftertreatment," Oak Ridge National Laboratory, Knoxville, TN, 2005.

[12] "Summary of Potential Retrofit Technologies, Technical Summary," U.S. Environmental Protection Agency, March, 2006.

[13] "WRAP Off-raod Diesel Retrofit Guidance Document, Volume 2, Section 4," November, 2005.

[14] Manufacturers of Emissions Controls Association, op cit.

Mitigation Option: Automation of Wells to Reduce Truck Traffic

Assumptions

About 50% of traffic on dirt roads in the Four Corners region is oil and gas related.

Substantially less than widespread implementation is likely, assume 25%.

Emissions estimates for road dust are of medium to low quality.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have an EPA-recommended factor applied that estimates the transportable fraction, i.e. that which would move beyond the immediate vicinity.

Automation would not quite “zero out” vehicle-related emissions for those wells that are automated because of non-routine maintenance, perhaps it would be reduced by 80%.

Vehicle miles traveled is proportional to dust generated.

Method

Applying the percent reduction, 80% reduced by 50% to account for extent of oil and gas traffic and further reduced by 75% to account for effectiveness. So, the over all reduction would be 10%.

Conclusions

For road dust, the total PM10 emissions in the region are 1959 tpy (tons per year), while the total of PM2.5 is 196 tpy based on WRAP inventory information. Hence, the estimated reduction in road dust emissions because of automation would by 196 tpy of PM10 and 20 of PM2.5.

For tailpipe emissions, the total NOx emissions in the region are 916 tpy, which means the reduction because of automation would be 92 tpy.

Mitigation Option: Reduced Truck Traffic by Centralizing Produced Water Storage Facilities

Assumptions

About 50% of traffic on dirt roads in the Four Corners region is oil and gas related.

Substantially less than widespread implementation is likely because it is voluntary, assume 20% participation which is a bit higher than is usually assumed for regulatory programs.

Emissions estimates for road dust are of medium to low quality.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have an EPA-recommended factor applied that estimates the transportable fraction, i.e. that which would move beyond the immediate vicinity.

Hauling of produced water constitutes about 20% of total O&G traffic.

Streamlining hauling might reduce such traffic by about 50%.

The relative mix of heavy duty compared to light duty vehicles is unknown, so estimating emissions reductions for this option might be a bit conservative since it is based on an overall average that includes both light- and heavy-duty and the approach is intended just for heavy-duty which produce more dust on a per unit basis.

Method

Based on the above assumptions of 50% of total traffic is oil and gas related, of which 20% are hauling produced water and of which 20% will likely undertake the program. Therefore, of the total unpaved road traffic generating road dust, 2% would be reducing emissions under this approach. One would then apply the 50% control efficiency.

Conclusions

For road dust, the total PM10 emissions in the region are 1959 tpy (tons per year), while the total of PM2.5 is 196 tpy based on WRAP inventory information. Hence, the estimated reduction in road dust emissions because of automation would by 39 tpy of PM10 and 4 tpy of PM2.5.

Mitigation Option: Reduced Truck Traffic by Efficiently Routing Produced Water Disposal Trucks

Assumptions

About 50% of traffic on dirt roads in the Four Corners region is oil and gas related.

Emissions estimates for road dust are of medium to low quality.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have an EPA-recommended factor applied that estimates the transportable fraction, i.e. that which would move beyond the immediate vicinity.

Hauling of produced water constitutes about 20% of total O&G traffic.

Streamlining hauling might reduce such traffic by about 50%.

Miles traveled is proportional to dust generated.

The relative mix of heavy duty compared to light duty vehicles is unknown, so estimating emissions reductions for this option might be a bit conservative since it is based on an overall average that includes both light- and heavy-duty and the approach is intended just for heavy-duty which produce more dust on a per unit basis.

Method

Based on the above assumptions of 50% of total traffic is oil and gas related, of which 20% are hauling produced water. Therefore, of the total unpaved road traffic generating road dust, 2% would be reducing emissions under this approach. One would then apply the 50% control efficiency.

Conclusions

For road dust, the total PM10 emissions in the region are 1959 tpy (tons per year), while the total of PM2.5 is 196 tpy based on WRAP inventory information. Hence, the estimated reduction in road dust emissions because of automation would by 196 tpy of PM10 and 20 tpy of PM2.5.

Mitigation Option: Reduced Vehicular Dust Production by Covering Lease Roads with Rock or Gravel

Assumptions

About 25% of traffic on dirt roads in the Four Corners region is on oil field lease roads.

Once applied, the improved surface would be maintained regularly by grading and reapplying gravel or rock.

Emissions estimates for road dust are of medium to low quality.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have had an EPA-recommended factor that estimates the transportable fraction, i.e. that which would move beyond the immediate vicinity.

The level of emissions reductions achieved by the application of gravel to roadways can vary from place to place.

Considering uncertainties in road dust emissions estimates, the more conservative end of a range will be used.

Method

The total annual road dust emissions of PM10 in the Four Corners region are 1959 tpy (tons per year), and 196 tpy of PM2.5 based on the inventory information from the WRAP.

Based on a comprehensive EPA study (Raile, 1996) conducted in the Kansas City, Missouri area, emissions of PM10 were reduced by 42% to 52% by the application of gravel.

Conclusions

Therefore, emissions of PM10 on lease roads would be reduced by about 206 tpy, and by about 21 tpy of PM2.5. This is based on the following:

reduction of particulate from lease roads =
total road dust emissions times 25% times 42%.

References

Raile, M.M. 1996. Characterization of Mud/Dirt Carryout onto Paved Roads from Construction and Demolition Activities. U.S. EPA. EPA/600/SR-95/171.

Mitigation Option: Reduced Vehicular Dust Production by Enforcing Speed Limits

Assumptions
The average posted speed is 30 mph.

About half of the vehicles on dirt road exceed the posted limit by more than 5 mph. The average for these drivers is 40 mph or 10 mph over.

Therefore, the reduction in speed for those exceeding posted limits would be about 10 mph if enforcement was undertaken and was 100% effective. Such enforcement is not 100% effective.

Road dust estimates made by the Western Regional Air Partnership (WRAP) have an EPA-recommended factor that estimates the transportable fraction, i.e. how much would move beyond the immediate vicinity.

The effectiveness of enforcement initiatives is dependent on resources allocated.

Method
The equation for estimating road dust PM10 emissions from EPA's AP-42 is:

((1.8*(silt content/12)^.1) * (veh. Speed/30)^.5) - .00036) /
(surface moisture/.5)^.2

Therefore, adjusting the vehicle speed would change the multiplier in the numerator from 1.15 (i.e. (40/30)^.5) to 1.0 (i.e. (30/30)^.5).

So, assuming even 50% effectiveness in mitigating speeding, and generally the assumption is lower, the reduction from enforcing a 30 mph speed limit on dirt roads in the entire Four Corners region would be about 7.5%.

Conclusions
Remembering that half of the traffic on dirt roads are exceeding the speed limit by more than the threshold 5%, applied to the total road dust emissions of PM10 of 1959 tpy, the reduction would be approximately 73 tpy. The reduction in PM2.5 from a total of 196 tpy would be 7 tpy.

Mitigation Option: Emissions Monitoring for Proposed Desert Rock Energy Facility to be Used Over Time to Assess and Mitigate Deterioration to Air Quality in Four Corners Region

Assumptions

Generally, much post-construction ambient monitoring for permitted facilities by the source is conducted on-site. Air quality permits generally contain conditions to require continuous emissions monitoring from the stacks for criteria pollutants. New federal mercury rules will require continuous emissions monitoring for mercury for Desert Rock Energy Facility beginning in 2010.

Given the tall stack heights of the proposed facility, the greatest air pollution impacts from emissions from the facility will be quite some distance from the facility.

Review of Proposed Approach

Continuous PM2.5 monitoring of primary fine particulate by the facility on-site would not likely provide useful information where the effect of emissions would be well downwind, plus direct fine particulate emissions by more modern power plants are usually not substantial. However, monitoring fine particulates and its chemical components (including ammonia) at off-site locations where models indicate significant impacts from the facility would be useful. Also, since much fine particulate is formed in the atmosphere rather than emitted directly, measurements of sulfur dioxide and oxides of nitrogen offsite would also be useful.

Stack mercury measurements might be useful from a research perspective in performing source apportionment work in the Four Corners region.

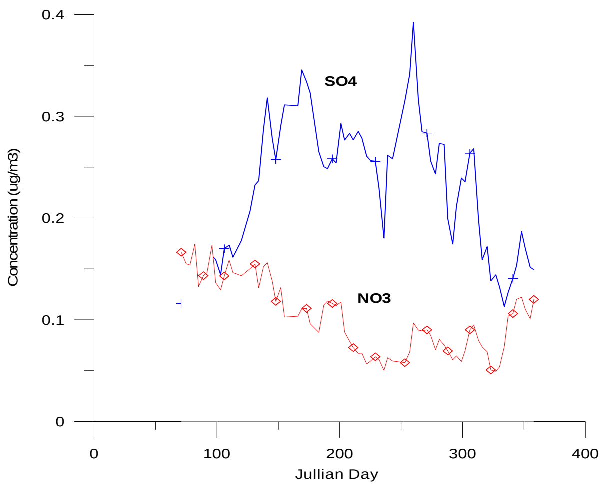
As is discussed above, on-site ambient monitoring of volatile organic compounds (VOC) may not be an effective means of understanding the ambient impact of these emissions, but off-site monitoring of ozone precursors like VOC and nitrogen oxides at predicted maximum impact locations would be useful.

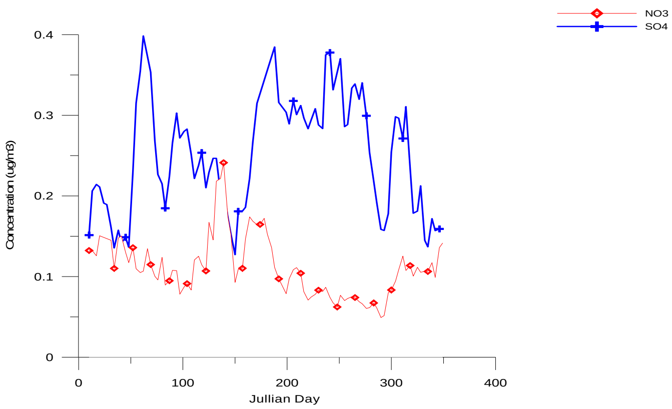
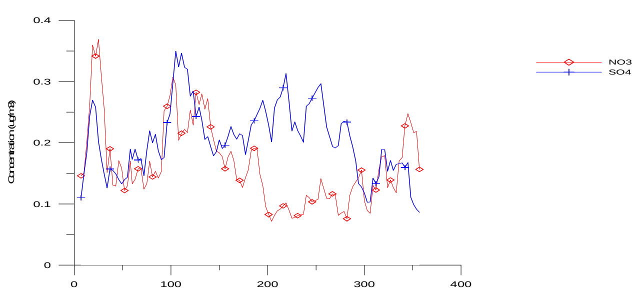
CUMULATIVE EFFECTS: PUBLIC COMMENTS

Cumulative Effects Public Comments

Comment	Mitigation Option
I have been concerned for many years about the air quality of the Four Corner's region because of the coal fired power plants in N.M. I attended two of the Four Corner's air quality forums in the past and was disturbed by their reports. As a nurse, I am especially concerned for the health of the Native Americans and other people who reside close to the power plants because of their incidence of lung disease. As a resident of La Plata canyon for 20+ years with a high mercury level, I am concerned about my own health and notice more air pollution, lack of visibility, every time I hike in the mountains. I believe for everyone's health, alternative sources of energy; e.g. solar, wind energy is a much better solution and would still serve as a revenue source to the Navajo nation. Desert Rock should not be built and the others should be phased out as planned many years ago or at least upgraded to standards that were set by the Clinton administration.	General Comment
We do NOT need another power plant in the 4 Corners. I notice the dirty air in this area all of the time and especially on weekends. Drive up from Albuquerque and see the air get dirtier. Also, go out from the 4 Corners and notice the beautiful blue skies as you progressively leave the area. I teach school and stress to my students they need to take care of the this planet earth because there is no spare earth. I would like to stress to everyone else that this needs to be done. Solar, wind and other energy sources should be used.	General Comment
It breaks my heart to think that another coal fired plant may be added to our "pristine" 4 corners area. Even in Pagosa Springs we have some hazy smog some days, and when driving south and west of Farmington, that horrible yellow-brown cloud can be seen for miles! I was shocked to see that poisonous cloud in Monument valley, and northwest Utah. It's all pervasive now so I can't imagine what it will be like with more coal -spewing plants. We must use non polluting energy sources for the health of all of us!	General Comment
The Task Force report presents data on the potential emission reductions for the Four Corners Power Plant and the San Juan Power Plant. The Cumulative Effects Work Group needs to evaluate potential power plant mitigation options that are presented in the report and develop a quantitative summary of all potential mitigations options which have technical merit. It is useful to place the emission reductions suggested for power plants in perspective to those developed for oil and gas sources. As stated in the Draft Report, for the Four Corners Power Plant the installation of presumptive BART could result in SO_2 emission reductions from a minimum of 12,455 tons per year to a maximum of 19,927 tons per year. Similarly, NO_x emission reductions could range from 13,651 tons per year to 57,118 tons per year. Since SO_2 and NO_x emissions are considered as having similar visibility impairment potential, the magnitude of the total emission reductions possibly affecting visibility could range from 26,106 to 77,045 tons per year. For the San Juan Power Plant using data presented in the Task Force Report, estimated SO_2 emission reductions could be approximately 9,000 tons per year and NO_x reductions could be approximately 11,000 tons per year. For this plant the combination of SO_2 and NO_x possible reductions of 20,000 tons per year might be achieved. The information contained in the Draft Report regarding possible emission reductions for this source is not as complete as for the Four	General Comment

Comment	Mitigation Option
Corners Plant and additional data should be developed and presented. If the suggested emission reduction strategies were implemented at both plants, total SO2 and NOx emission reductions of visibility impairment pollutants could range from 46,106 tons per year to 97,046 tons per year. In addition, review of the emission data in the Draft Report indicates that at the Four Corners Power Plant NOx emissions are greater than SO2 emissions (Figure 2 FCPP Emission Trends). However, in 2003 SO2 emissions were further reduced so that the ratio of NOx to SO2 emissions increased. At the San Juan Power Plant prior to 1990, SO2 emissions were greater than NOx emissions while in 1999 SO2 and NOx emissions were equal (Figure 1 San Juan SO2 and NOx). After that time, SO2 emissions were less than NOx emissions. The trends in emissions at these facilities may be important in understanding the trends in the IMPROVE monitoring data. Engineering and economic feasibility studies need to evaluate the ability of the facilities to continuously achieve emission reductions in a cost effective manner. The potential emission reduction that could be realized with the installation of additional controls on power plants need to compared with the emission reductions reported by the Draft Task Force Report for oil and gas sources. The installation of NSCR on existing small engines in Colorado and New Mexico could result in emission reductions of approximately 10,244 tons per year. These emission reductions are only a small fraction of the reductions possible from power plants (minimum ratio of power plant reduction to oil and gas reductions 4.5 – maximum ratio of power plant reduction to oil and gas reductions 9.5).	
The Draft Task Force Report presents recommendations for mitigating emissions from drilling rig diesel engines. At the present time there is insufficient information regarding the level of emissions from these sources in the region. The Cumulative Effects Group should develop emission data regarding the magnitude of emissions in both Colorado and New Mexico and then develop estimates of potential emission reductions that could be achieved. The emission calculations should be based on site specific information that represents the length of time to drill a new well, engine loads and engine capacity. One important fact that needs to be considered is that the drilling rig engines are typically replaced at a frequency of every 5 years (replaced not rebuilt). This rate of turnover is very important because the engines are replaced with the required current control technology. This should be the baseline against which alternative mitigation options should be considered. It is recommended that the Cumulative Effects Group continue to analyze and evaluate emission reduction options for this source group.	General Comment
The following plots present selected years of rolling 5 data point averages of the SO4 and NO3 concentrations compared to Julian day for the IMPROVE data from Mesa Verde. Using a rolling 5 data point average provides some smoothing of the data but allows correlations between SO4 and NO3 to be observed. The plots for 1988 and 1990 indicate a large fraction of coincident peaks of SO4 and NO3. This is an important finding because it suggests that these events may result from coal fired sources because natural gas fired sources or mobile sources do not emit significant SO2. In addition, NO3 concentrations are smaller than SO4 concentrations. The data from 2002, 2003 and 2004 indicate that a change has occurred in the relationship of SO4 and NO3 measurements and that there is a very strong correlation of SO4 and NO3	General Comment

Comment	Mitigation Option
events, again suggesting a coal fired source. However, in 2002, 2003 and 2004 NO3 concentrations are equal to or greater than SO4 concentrations. As mentioned in the power plant emission section, SO2 reductions began in 1999 and after that time NOx emissions were greater than SO2 emissions. This trend in changes in emissions is very consistent with the monitoring data and again suggests visibility impacts are likely from coal fired sources. This is a preliminary hypothesis that needs more evaluation and may explain why NO3 levels have been increasing at Mesa Verde. If this finding is confirmed, it has important ramifications regarding improvement in air quality. This is the type of focused analyses that needs to be conducted before mitigation options are selected and implemented.  **1988 SO4 and NO3 Concentrations 5 Day Running Average** **Mesa Verde**	

Comment	Mitigation Option
 1990 SO4 and NO3 concentrations 5 day running average  **2002 SO4 and NO3 Concentrations 5 Day Running Average Mesa Verde**	

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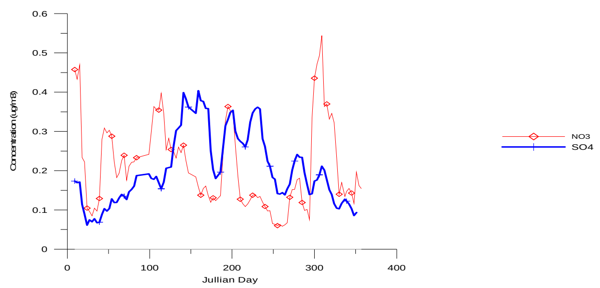
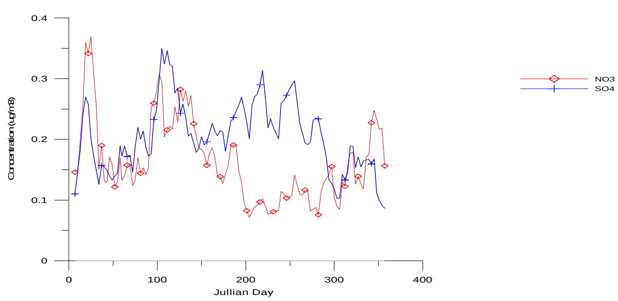


2003 SO4 and NO3 Concentrations 5 Day Running Average
Mesa Verde



2004 SO4 and NO3 Concentrations 5 Day Running Average
Mesa Verde
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<tr><td>last paragraph before Suggestions for Future Work...should the reference be to Table 2 rather than Table 1?</td><td>Overview of Work Performed</td></tr>
</table>

Comment	Mitigation Option
Table 1 - Selective Catalytic Reduction (SCR) on Drilling Rig Engines: It is stated "that some data exists on drilling emissions. The State of Wyoming evaluated this technology based on a pilot study in the Jonah Field & concluded that is not a cost effective technology, but further analysis is needed." This paragraph references the cost analysis WY did for SCR on diesel rig engines, but does not provide or reference any information on what conditions and assumptions WY used in conducting this analysis. If possible the CE workgroup should obtain and review the WY analysis on SCR, in addition to other diesel control options WY analyzed. Table 1 - Follow EPA New Source Performance Standards (NSPS) for RICE: EPA suggests revising the Summary of Result first sentence "This proposed emission standard will become the baseline for new, **modified, and reconstructed** engines. Table 1 - Install Non Selective Catalytic Reduction (NSCR) on Rich Burn Engines for RICE. It is unclear in the Summary of Result what EPA performance standard is being referenced, and how the 4 Corners Task Force Interim Emissions Recommendations for Stationary RICE have been considered by the CE workgroup. The NSPS for spark ignition engines will apply to **new, modified, and reconstructed** units starting in January 2008. The 4 Corners Task Force Interim Emissions Recommendations for Stationary RICE notes that BLM/USFS, at the request of CO and NM, is currently requiring NSPS comparable emission limits on as a Condition of Approval for their Applications for Permits to Drill. The States' request was that BLM/USFS immediately establish in every Application for Permit to Drill (APD) a nitrogen oxide (NOx) limit of 2.0 grams per horsepower hour for all **new and replacement** engines less than 300 hp (excluding engines with horsepower less than 40). In addition, New Mexico and Colorado have requested that for all new and replacement engines greater than 300 hp, the BLM and the USFS establish in every APD a NOx limit of 1.0 gram per horsepower hour. EPA Region 8 formally supports both these requests from Colorado and New Mexico. It should also be noted that the Mitigation Option: Interim Emissions Recommendations for Stationary RICE section in the Draft Mitigation Options Report states that "BLM in New Mexico and Colorado are currently requiring these emission limits as a Condition of Approval for their Applications for Permits to Drill. These limits currently apply only to **new and relocated** engines ... (compressors assigned to the well APD)..." In developing assumptions for potential NOx reductions from this requirement in APDs, how did the CE workgroup determine, or assume, what percentage of the existing engines (compressors) in the 4 Corners area would be required to meet this requirement?	Overview of Work Performed

Comment	Mitigation Option
1. Given electric compression would shift emissions generated from NG compressor engines through use of electric engines to emissions from power generation (i.e., "the grid"), this option is clearly "cross-cutting." We recommend that the coordination with the Power Plant WG in the analysis of this option. 2. We were unable to reproduce the emission reduction numbers from the data provided in the analysis (tons/yr deltas provided in Table 4). Based on the data provided we calculate a total of 631 tons/yr reductions in NOx and SO2 based the 25 worst engines and the average power plant emissions in Table 3. 3. In course of installing electric compression to replace the natural gas fired compression engines, the analysis correctly assumes that the emission of pollutants will shift from the replaced compressor engines to increased electric load demand from the grid. In course of review of the Natural Resources Defense Council (NRDC) "Emission Data for the 100 Largest Power Producers", it appears that baseline average emission factors used for emission difference calculation are the national average emission factors for the identified owner utility companies (average of all plants, regardless of location or on which power grid). The electric power for electric compression will come from the Western Grid which draws power from generating stations in the western United States. Among the three electric power producers, Xcel is the largest producer with 81,283,493 MWhs capacity compare to 21,230,675 MWhs for both PNM and Tri-state. The baseline average emission factors based on national average emission factors of these three electric power producers have potential to distort the emission difference calculation because Xcel's power generation facilities in Minnesota, South Dakota, Texas, and Wisconsin are not supplying electricity to the Western Grid. A brief description of grid system is provided later in this document. A better measure of the effectiveness of this option would be the use of average NOx and SO2 emissions from Four Corners Generating Station and San Juan Generating Station. In case example case provided in the analysis, replacing 25 worst engines with total 2,701 hp in NM side with electric compression, will result in net NOx + SO2 reduction of 610 tons/year. A net NOx +SO2 reduction of approximately 20,000 tons/year can be achieved by replacing all rich burn engines (approximately 1,500 in NM inventory) emitting greater than 5 g/hp-hr. Although it may not be practical or economically feasible to replace all rich burn compressor engines with electric motors, further analysis of the locations/ configurations of existing compressor stations may reveal that conversion to electric is practical and makes sense. Factors like proximity to the electric grid, ROW, number of engines, are factors that would need to be evaluated. 4. The electricity for the electric compression in the San Juan area will be drawn from Western Interconnect or Grid. We recommend that a good approximation for baseline emission factors will be the averages of emission factors for the power plants supplying electricity to the Western Grid. The following steps can be taken to obtain the baseline average emission factors for the emission difference calculation: a. The average emission factors for fossil fuel powered power plants supplying electric power to the Western Grid can be calculated using the emission data	Install Electric Compression

Comment	Mitigation Option
from the EPA's CAMD inventory. The EPA's Clean Air Market Data (CAMD) (http://camddataandmaps.epa.gov/gdm/index.cfm) provides NOx, SO2, and CO2 emission as well as heat input for the Title IV power generating units. b. The net power generation by state by type of producer by energy source is available at the Energy Information Administration (EIA) website (http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html). c. A fraction between calculated average baseline emission factors for the Western Grid based on EPA data and the total power generation for the Western Grid obtained from EIA's website will used to obtain the average baseline emission factors for emission difference calculations. 5. The worst case NOx emissions from coal-fired plants is 4.5 lbs/MWh, which is equivalent to 1.5 g/hp-hr. The coal-fired plants produce a lot more NOx emissions than the gas field sources do: 160,264 tons/year compared to 38,632 tons/year. A 5% reduction of NOx emissions from the coal-fired plants is the same as a 21% reduction in NOx from gas field sources. 6. We recommend that the Task Force evaluate on-site lean-burn electric generators as an alternative power source for electric compression.	
The SUGF recommends further research and testing of this mitigation option to help determine the amount of emissions reduction that can be accomplished on a continual, reliable basis. If technology could be developed and maintained on a regular basis, this option could prove to be valuable in retrofitting existing rich burn units.	Use of NSCR for NOx Control on Rich Burn Engines
In the section Mitigation Option: Use of NSCR for NOx Control on Rich Burn Engines it is stated in the Assumptions (p. 13): "Currently, recent EIS RODs in Colorado and New Mexico require performance standards for new engines that will accelerate the implementation of the 2008 and 2010 federal NSPS for non road engines." The term "replacement" is not used, only "new" engines. What is the CE workgroups understanding related to what type of engines would fall under the replacement category, and was this type of engine considered in the assumptions as being retrofitted to meet the interim recommendation of 2 g/hp/hr? Engine Size < 100 hp Case 1 (p. 14): It is stated that "it was assumed that NSCR for this situation would reduce NOx emissions by 50 percent in Colorado and New Mexico and would result in a NOx emission factor of 6.7 g/hp-hr in Colorado and 8.0 g/hp-hr in New Mexico." What is the basis for this assumption? The 2 g/hp-hr interim recommendation for new and replacement engines 300 hp and less (excluding engines less than 40 hp) has been in place since '05, which is almost 3 years ahead of the NSPS implementation date. Does the CE Workgroup have any information on how much impact this interim recommendation, as implemented through BLM/USFS APDs, has had on the average NOx emission factor from the current engine fleet in the 4 Corners area. Tables 6 and 7: Can some narrative be added that explains how emissions reductions are calculated and what each column in the tables represents? Why is table 6 (CO) different from table 7 (NM)? It is unclear how some of the emission reduction values have been calculated in tables 6 and 7. For example, in table 6 why is the emission reduction for < 100 Hp engines 130 TPY instead 143 TPY (50% x 286 TPY)?	Use of NSCR for NOx Control on Rich Burn Engines

Comment	Mitigation Option
1. Test data on small two-stroke NSCR retrofitted engines (Ajax DP-115) show NSCR can achieve large NOx emission reductions between 79% and 93% (Chapman, 2004a). On four stroke engines Chapman (2004b) indicates that "these catalyst systems reduce NOX emissions by over 98 percent, while reducing VOC by 80 percent and carbon monoxide by over 97 percent. NOx levels in the range of 0.1 to 1.0 g/bhp-hr have been achieved." Although this is consistent with the statement in the Draft Report that NSCR can achieve NOx emissions of less than 2 g/hp-hr, tighter control levels can certainly be achieved in retrofitting rich burn engines with a well controlled NSCR system. 2. Not all rich-burn engines would need to be retrofitted to NSCR to achieve the reductions postulated in the Draft Report. For example, if 57% of the under-100-hp engines in New Mexico were retrofitted with NSCR, which achieves less than 2 g/hp-hr NOx emissions (this is a conservative number, since NOx emissions that are well under 1 g/hp-hr are possible), then the overall emissions rate for that class of engine would decrease from 16 g/hp-hr to 8 g/hp-hr. According to Table 7 in the Draft Report, this would mitigate 6337 tons/yr of NOx (6694 tons/yr with growth). Since only 57% of the engines in this classification would need to be retrofitted, a retrofit kit would need to be developed only for the most common engine model (or a few models, at most.) This would save the expense of engineering development for engine models that have only a few examples represented in the Four Corners area and would concentrate the engineering effort where it would do the greatest amount of good. If more that 57% of the engines were controlled at the 2 g/hp-hr level, then more that 6337 tons/yr of NOx would be mitigated, but the incremental cost per tons/yr of NOx would be higher than that of the first 6337 tons/yr. It should also be noted that if the 57% of engines with NSCR controlled NOx at the 1 g/hp-hr rather than 2 g/hp-hr, 6773 tons/yr of NOx world be mitigated. This is an additional 436 tons/yr. A number of issues are identified with the use of NSRC on small engines. All of these issues, including ammonia formation, can be eliminated or minimized through use of a NSCR retrofit package that includes all the right components. The appropriate NSCR retrofit kit should include: - A 3-way catalytic converter - Exhaust oxygen sensor - Replace existing carburetor with a controllable air/fuel ratio (AFR) controller device. The ratio of an engine's actual AFR to the stoichiometric AFR for the fuel being used is referred to as the Lambda parameter. To ensure that exhaust bound O2 comprises no more that 0.5% (by volume) of the total engine exhaust, rich burn engines operate at λ's of between 0.988 and 0.992 (Chapman, 2004b). (For engines burning clean, dry natural gas, the air to fuel ratio (AFR) for stoichiometry is ~16.1:1, Chapman, 2004a). - Computerized control using feedback from the exhaust oxygen sensor to control the air/fuel ratio λ's of between 0.988 and 0.992 with the retrofitted NSCR system. - Exhaust gas recirculation (EGR) and controllable ignition timing could also be included and controlled by the same computer. Both EGR and retarded ignition timing reduce engine-out NOx emissions and enhance the effectiveness of the catalyst. Retarded ignition timing also has the effect of increasing exhaust temperature, which will improve the effectiveness of the catalyst at light engine	Use of NSCR for NOx Control on Rich Burn Engines

Comment	Mitigation Option
loads. Although considerable engineering effort is required to develop the retrofit kit, it needs to be done for only one engine model or a few engine models, at most. In the 3rd parg. under engines < 100 hp, it states; "Also, research indicates that if the AFR drifts off the optimal setting, then NOx emissions may be converted (on an equal basis) to ammonia. If this occurs within the discharge plume of an engine, it may accelerate the conversion of NOx emissions into particulate nitrate. This is the reason that the carburetor must be replaced with a more accurate AFR controller having feedback from an exhaust oxygen sensor. With such a system, accurate AFR control is achieved, and generation of ammonia is not an issue. Chapman, K., 2004a, Report 6: Cost-Effective Reciprocating Engine Emissions Control and Monitoring for E&P Field and Gathering Engines, Technical Progress Report, DOE Award DE-FC26-02NT15464, Kansas State University, August Chapman, K., 2004b, Report 4: Cost-Effective Reciprocating Engine Emissions Control and Monitoring for E&P Field and Gathering Engines, Technical Progress Report, DOE Award DE-FC26-02NT15464, Kansas State University, January	
The assumption of 50% reduction of NOx in the Draft Report is too pessimistic or small. Other information indicates that NOx reduction greater than 90% is achievable. Another report indicated 95.9% NOx reduction on a 320 kW (430 hp) natural-gas fueled engine. The same report gave costs of $2,205-$3,684 per ton of NOx removed. This is considerably less than the $10,300 per ton of NOx removed indicated in the Draft Report. Another report indicated that the cost of SCR on reciprocating natural-gas engines varied from $30-$250 per horsepower with no correlation to engine size. Considering that the date of the fourth report is 1990, one reason for the variation in cost may be lack of experience on the part of some installers. Using the same methodology that was used in the Draft Report, but allowing a 90% NOx reduction on new engines instead of 50% gives a reduction of 1789 tons/year (16.5% reduction of overall NOx) in Colorado and a reduction of 2015 tons/year (4.6% reduction of overall NOx in New Mexico. The 90% NOx reduction should be achievable with good operation and maintenance practice in light of the 95.9% NOx reduction already achieved in the field. These figures were for new engines greater than 500 hp. Since the reported engine was smaller than 500 hp, the same calculation was performed for new engines greater than 300 hp. These gave a reduction of 2,109 tons/year (19.5%) in Colorado and 2502 tons/year (5.8%) in New Mexico. The engines with SCR would have NOx emissions of about 0.1 g/hp-hr. 1. Jim McDonald and Xavier Palacios, "Compressor Tech 2: SCR for Gaz de France," Miratech Corporation, Tulsa, OK, December 1, 2002. 2. Johnson Matthey Corp., "Maximum NOx Control for Stationary Diesel and Gas Engines," brochure number "jm_brochure_scr_062306b.pdf". 3. Ravi Krishnan, RJM Corp., "Urea-based SCR technology achieves 12 ppm NOx on natural gas engine," PennWell Power Group Online Article available at http://pepei.pennet.com/Articles/Article_Display.cfm?ARTICLE_ID=156191,	Use of SCR for NOx Control on Lean Burn Engines

Comment	Mitigation Option
October 1, 2002. 4. G.S. Shareef and D.K. Stone, "Evaluation of SCR NOx controls for small natural gas-fueled prime movers. Phase 1. Topical Report," report number PB-90-270398/XAB; DCN-90-209-028-11; GRI-5089-254-1899, Radian Corp., Research Triangle Park, NC, July 1, 1990.	
The first paragraph of the section on Next Generation RICE Stationary Technology in the Draft Report does not give adequate weight to the importance of next generation technology. As emissions regulations become tighter (e.g., 0.2 g/hp-hr NOx in 2010), those limits will become increasingly difficult to meet with existing technology. Continuing research on advanced technologies is necessary to ensure than ever tighter limits in the future can be met. Three of the technologies listed below, NOx trap catalysts, laser ignition, and HCCI, are close to meeting the 0.2 g/hp-hr limit by themselves. Two of the technologies, laser ignition and HCCI, may be able to meet the 0.2 g/hp-hr limit without aftertreatment. With aftertreatments they may be able to meet an even lower limit. NOx trap catalysts are an aftertreatment that offers the same performance as SCR, but with potentially lower cost. Air separation membranes may be used in combination with other technologies to outperform the 0.2 g/hp-hr limit. NOx trap catalysts are similar in performance to SCR, that is they can reduce more than 90% of the engine-out NOx to achieve less than 1 g/hp-hr NOx emissions.[1] The estimates of NOx abatement used in the Cumulative Effects SCR section of the draft report may be used as a guide to the abatement potential of NOx trap catalysts. The cost is expected to be less than that of SCR because ammonia or urea is not used as a reductant. Instead, some of the fuel is used as a reductant. The increase in fuel consumption may be up to 8%, but is typically about 4%. Air separation membranes used to deplete oxygen from the intake air have an effect on NOx emissions that is similar to that of exhaust gas recirculation (EGR) in rich-burn and diesel engines. Combined with ignition retardation, a reduction in engine-out NOx of up to 40% can be expected.[2,3] For engines in the 300-500 hp range, air separation membranes with ignition retard could reduce overall NOx emissions to 2 g/hp-hr in both Colorado and New Mexico. For the 100-300 hp range, these technologies could reduce overall NOx emissions from 16.3 to 10 g/hp-hr in Colorado and from 12.5 to 7.5 g/hp-hr in New Mexico. For engines under 100 hp, the technologies could reduce overall NOx emissions from 13.4 to 8 g/hp-hr in Colorado and from 16 to 9.6 g/hp-hr. Laser ignition may be able to reduce NOx emissions by as much as 70% in lean burn engines.[4] However, in the reference cited, the baseline emissions for the engine with spark ignition were higher than the emissions that are currently achievable with lean burn engines. Additional development and testing will be required to verify the reduction of NOx emissions. There is little information in the literature about lean NOx catalysts used with lean burn natural gas engines. Information about lean NOx catalysts used with diesel engines indicates NOx reductions of 10-40% depending on whether fuel is used as a reductant.[5,6] NOx reductions for lean burn natural gas engines is expected to be similar. Although researchers are attempting to improve the conversion efficiency of lean NOx catalysts, their current low performance makes them unsuitable for the short term. Only a few experimental measurements of NOx from homogeneous-charge	Next Generation Stationary RICE Technology

Comment	Mitigation Option
compression-ignition (HCCI) engines have been reported. The measurements are typically reported as a raw NOx meter measurement in parts per million rather than being converted to grams per horsepower-hour. Dibble reported a baseline measurement of 5 ppm when operated on natural gas.[7] Green reported NOx emissions from HCCI-like (not true HCCI) combustion of 0.25 g/hp-hr.[8] Whether HCCI technology can be applied to all engine types and sizes is not known. In addition, the ultimately achievable NOx emissions from such engines is not known. However, if all reciprocating engines could be converted to HCCI so that the engines produce no more than 0.25 g/hp-hr, then the overall NOx emissions reduction would be 80% in both Colorado and New Mexico using the calculation methodology of the SCR mitigation option. ____ 1 James E. Parks II, Douglas Ferguson III, and John M. E. Storey, "NOx Reduction With Natural Gas for Lean Large-Bore Engine Applications Using Lean NOx Trap Aftertreatment." Oak Ridge National Laboratory, 2360 Cherahala Blvd., Oak Ridge, TN 37932. 2 K. Stork and R. Poola, "Membrane-Based Air Composition Control for Light-Duty Diesel Vehicles: A Cost and Benefit Assessment," Report Number ANL/ESD/TM-144, Argonne National Laboratory, 9700 South Cass Avenue, Argonne, IL 60439, October 1998. 3 Joe Kubsh, "Retrofit Emission Control Technologies for Diesel Engines," NAMVECC 2003, Manufacturers of Emission Controls Association, www.meca.org, Chattanooga, TN, November 4, 2003. 4 B. Bihari, S. B. Gupta, R. R. Sekar, J. Gingrich, and J. Smith, "Development of Advanced Laser Ignition System for Stationary Natural Gas Reciprocating Engines," ICEF2005-1325, ASME-ICE 2005 Fall Technical Conference, Ottawa, Canada, 2005. 5 Joe Kubsh, op.cit. 6 Carrie Boyer, Svetlana Zemskova, Paul Park, Lou Balmer-Millar, Dennis Endicott, and Steve Faulkner, "Lean NOx Catalysis Research and Development", Caterpillar Inc., presented at the 2003 Diesel Engine Engineering Research Conference. 7 Robert Dibble, et al, "Landfill Gas Fueled HCCI Demonstration System," CA CEC Grant No: PIR-02-003, Markel Engineering Inc. 8 Johney Green, Jr., "Novel Combustion Regimes for Higher Efficiency and Lower Emissions," Oak Ridge National Laboratory, "Brown Bag" Luncheon Series, December 16, 2002.	
The SUGF recommends further examination of the above listed mitigation options as particulates associated with each option contribute to local visibility issues.	Automation of Wells to Reduce Truck Traffic Reduced Truck Traffic by Centralizing Produced Water Storage Facilities

Monitoring

MONITORING: PREFACE

Overview
The charter for the Monitoring Workgroup was as follows:

> "The monitoring workgroup will review information provided on existing monitoring networks, and then identify data gaps and options for additional monitoring in cooperation with the other work groups. A gap analysis and trends analysis will be the basis for identifying options for additional monitoring. The monitoring workgroup will identify potential funding sources and develop a holistic monitoring strategic plan for the region."

Group Membership
The Monitoring Group was quite diverse. Members included private citizens from the Durango-Cortez-Aztec area, National Park Service personnel, U. S. Forest Service personnel, the Director of Research and Education at Mountain Studies Institute, a University of Denver graduate student, Tribal air quality personnel (Southern Ute and Navajo Nation), a private consulting hydrologist, air quality staff from two state agencies (New Mexico and Colorado), and personnel from two EPA regions (VI and VIII), among others.

Scope of Work
The following scope of work, including "specific tasks" and "discussion" for the Monitoring Group, was established at the onset of the Task Force.

Specific Tasks
D. Identify existing monitoring networks located in the Four Corners study area. Review information provided by these networks to identify data gaps.
E. Conduct data analyses to determine pollutant trends within the Four Corners study area.
F. Using the gap analysis and trend analysis, identify options for additional monitoring.
G. Incorporate public input when developing a monitoring strategy.
H. Identify potential funding sources for additional monitoring sites.
I. Develop final monitoring strategies for the Four Corners study area.

Discussion
The work group examined the various agency monitoring networks to determine present monitor locations and types, and pollutants or parameters being measured. Using this evaluation the work group identified locations within the study area that lack adequate representation in terms of pollutant data. Available data from the monitoring networks were analyzed to establish pollutant trends. The method and extent of establishing additional monitoring capabilities was dictated by the results from the network studies and from the data analyses. Public input was also addressed during the consideration of potential monitoring site locations. Once it had been established where monitoring sites were needed and what pollutants or parameters were to be measured, the work group identified potential funding sources.

Task 1
In identifying the existing monitoring networks located in the Four Corners study area, a matrix was developed. The matrix attempted to list all known air pollutant monitoring sites and meteorological monitoring sites within the study area. The type of site and the parameters measured at that site were listed in the matrix. The matrix was comprised of four spreadsheets; one having "site information", one having the "criteria sites", one having the "deposition sites", and one having the "meteorological sites".

Task 2
Data from agency databases were used to generate wind and pollution roses, and to generate graphs of pollutant trends. "Overlays" of pollution roses on both political boundary maps and on topographic maps have been produced. The trend graphs plot various pollutant concentrations since 1990.

Task 3
Once the gap analysis and the data analyses had been conducted, the work group assessed the types of monitors required and optimal site locations in the Four Corners study area.

Task 4

Because public sentiment and concern regarding air quality was of great importance to the Four Corners Air Quality Task Force, available public input was considered prior to any final suggestions of site location and type. Some of this input came from public citizens who are part of the task force.

Task 5

To provide the public with some idea of what it takes to set up a new monitoring site, two spreadsheets were created to show both capital and operating costs of two different agency sites. The work group identified potential funding sources for additional monitoring sites.

Task 6

A variety of monitoring strategies/suggestions were developed. These included ozone and ozone precursors, mercury, nitrate and sulfate, and visibility.

EXISTING MONITORING NETWORKS

Monitoring Site Matrix Narrative
The Four Corners Area Monitoring Site Matrix is an attempt to list all of the various air quality monitoring sites in the Four Corners area as well as the predominant meteorological monitoring sites. The following explanations refer to the major column headers of the various matrix pages.

Monitoring Programs
All of the air quality programs are represented in the matrix (some sites are under multiple programs) and are listed below. The following descriptions of the programs are from each program's web site:

ARM-FS: Air Resource Management, USDA Forest Service
The Real-Time Images section features live images and current air quality conditions from USDA-FS monitoring locations throughout the United States. Digital images from Web-based cameras are updated every 15 to 60 minutes. Near real-time air quality data and meteorological data are also provided to distinguish natural from human-made causes of poor visibility, and to provide current air pollution levels to the public.

CASTNET: Clean Air Status and Trends Network, EPA
CASTNET provides atmospheric data on the dry deposition component of total acid deposition, ground-level ozone and other forms of atmospheric pollution. CASTNET is considered the nation's primary source for atmospheric data to estimate dry acidic deposition and to provide data on rural ozone levels. Used in conjunction with other national monitoring networks, CASTNET can help determine the effectiveness of national emission control programs.

Each CASTNET dry deposition station measures:
- weekly average atmospheric concentrations of sulfate, nitrate, ammonium, sulfur dioxide, and nitric acid;
- hourly concentrations of ambient ozone levels; and
- meteorological conditions required for calculating dry deposition rates.

CoAgMet: Colorado Agricultural Meteorological Network
In the early 1990's, two groups on the Colorado State campus, the Plant Pathology extension specialists and USDA's Agricultural Research Service (ARS) Water Management Unit, discovered that they had a mutual interest in collecting localized weather data in irrigated agricultural area. Plant pathology used the data for prediction of disease outbreaks in high value crops such as onions and potatoes, and ARS used almost the same information to provide irrigation scheduling recommendations.

To leverage their resources, these two formed an informal coalition, and invited others in the ag research community to provide input into the kinds and frequency of measurements that would be most useful to a broad spectrum of agricultural customers. A standardized set of instruments was selected, a standard datalogger program was developed, and a fledgling network of some eight stations was established in major irrigated areas of eastern Colorado. As interest grew and funds were made available, primarily from potential users, more stations were added.

Initially, stations were located near established phone service to allow daily collection of data. Soon, cellular phone service began to become widely available, and the group determined that this methodology was a reliable and inexpensive method of data recovery. Commercial software was used to download data from the growing list of stations shortly after midnight to a USDA-ARS computer, from which it was then distributed to interested users via answering machine, automated FAX and satellite downlink (Data Transmission Network).

As the network grew, Colorado Climate Center at Colorado State became interested in these data, and subsequently took over the daily data collection and quality assessment. CCC added internet delivery and a wide range of data delivery options, and continues to improve the user interface in response to a growing interest in these data.

IMPROVE: Interagency Monitoring of Protected Visual Environments
Recognizing the importance of visual air quality, Congress included legislation in the 1977 Clean Air Act to prevent future and remedy existing visibility impairment in Class I areas. To aid the implementation of this legislation, the IMPROVE program was initiated in 1985. This program implemented an extensive long term monitoring program

to establish the current visibility conditions, track changes in visibility and determine causal mechanism for the visibility impairment in the National Parks and Wilderness Areas.

NADP/NTN: National Atmospheric Deposition Program, National Trends Network
The National Atmospheric Deposition Program/National Trends Network (NADP/NTN) is a nationwide network of precipitation monitoring sites. The network is a cooperative effort between many different groups, including the State Agricultural Experiment Stations, U.S. Geological Survey, U.S. Department of Agriculture, and numerous other governmental and private entities. The NADP/NTN has grown from 22 stations at the end of 1978, our first year, to over 250 sites spanning the continental United States, Alaska, and Puerto Rico, and the Virgin Islands.

The purpose of the network is to collect data on the chemistry of precipitation for monitoring of geographical and temporal long-term trends. The precipitation at each station is collected weekly according to strict clean-handling procedures. It is then sent to the Central Analytical Laboratory where it is analyzed for hydrogen (acidity as pH), sulfate, nitrate, ammonium, chloride, and base cations (such as calcium, magnesium, potassium and sodium).

NADP/MDN: National Atmospheric Deposition Program, Mercury Deposition Network
The Mercury Deposition Network (MDN), currently with over 90 sites, was formed in 1995 to collect weekly samples of precipitation which are analyzed by a prominent laboratory for total mercury. The objective of the MDN is to monitor the amount of mercury in precipitation on a regional basis; information crucial for researchers to understand what is happening to the nation's lakes and streams.

NWS: National Weather Service
Feb. 9, 2005 - The NOAA National Weather Service is celebrating its 135th anniversary amid a renewed commitment to preserve its history.

On February 9, 1870, President Ulysses S. Grant signed a joint resolution of Congress authorizing the Secretary of War to establish a national weather service. Later that year, the first systematized, synchronous weather observations ever taken in the U.S. were made by "observer sergeants" of the Army Signal Service.

Today, thousands of weather observations are made hourly and daily by government agencies, volunteer/citizen observers, ships, planes, automatic weather stations and earth-orbiting satellites.

"Since the beginning, the mission of the National Weather Service to protect life and property has been and remains to be the top priority," said Brig. Gen. David L. Johnson, U.S. Air Force (Ret.), director of NOAA's National Weather Service. "Advances in research and technology through the decades have allowed the NOAA National Weather Service to create an expanding observational and data collection network that tracks Earth's changing systems."

RAWS: Remote Automated Weather Stations
There are nearly 2,200 interagency Remote Automated Weather Stations (RAWS) strategically located throughout the United States. These stations monitor the weather and provide weather data that assists land management agencies with a variety of projects such as monitoring air quality, rating fire danger, and providing information for research applications.

SLAMS: State/Local Air Monitoring Stations
These ambient air monitoring sites are designated by EPA as State/Local Air Monitoring Stations (SLAMS). Pollutants monitored are the criteria pollutants, and include ozone, particulate matter, carbon monoxide, lead, sulfur dioxide, and oxides of nitrogen.

SPMS: Special Purpose Monitoring Stations
Special Purpose Monitoring Stations provide for special studies needed by the State and local agencies to support State implementation plans and other air program activities. The SPMS are not permanently established and, can be adjusted easily to accommodate changing needs and priorities. The SPMS are used to supplement the fixed monitoring network as circumstances require and resources permit. If the data from SPMS are used for SIP purposes, they must meet all QA and methodology requirements for SLAMS monitoring.

Tribal: Tribal Jurisdiction
These sites are under tribal jurisdiction and are the tribal equivalent to SLAMS sites, monitoring the same criteria pollutants.

Period of Record
The period of record refers to how long a site has been in operation. In some cases, dates refer to monitoring of major parameters at a site.

In the case of the NWS sites, the “start” dates are the dates when the NWS data was inserted into the MesoWest database which is maintained by the University of Utah’s Department of Meteorology.

Distance From
The distances listed refer to the distance from each monitoring site to two representative Four Corners cities; one in Colorado and one in New Mexico. The distances were obtained either from Argonne National Lab’s interactive Four Corners Aerometric Map or Google Maps. Other “site-to-city” distances can be determined by using either map.

Criteria Pollutants
EPA uses six "criteria pollutants" as indicators of air quality, and has established for each of them a maximum concentration above which adverse effects on human health may occur. Explanations of these pollutants can be found on EPA’s “Green Book” website,
http://www.epa.gov/oar/oaqps/greenbk/o3co.html

Meteorological
These columns indicate what meteorological parameters are monitored at a given site. The parameters are: wind (usually speed and direction), temperature (usually 2-meter and 10-meter), delta T (the difference between 2-meter and 10-meter), solar radiation, relative humidity, and precipitation.

Deposition
The parameters refer to those monitored by The National Atmospheric Deposition Program/National Trends Network (NADP/NTN).

The passive ammonia sampling sites are also listed on the “Deposition” page.

Key to Matrix Symbols
The following explanation refers to the various symbols used within the matrix cells.

h: Sampled and/or averaged hourly
1d/3d: Sampled once every three days
1d/6d: Sampled once every six days
w: Sampled weekly
3w: Sampled every three weeks

Monitoring Site General Information

Site	Program	Address	AQS / Other Code	Period of Record From	Period of Record To	Latitude	Longitude	Elevation (meters)	Distance from: (Km) Farmington	Distance from: (Km) Durango
Substation	SLAMS	16 mi. NW of Farmington, NM	35-045-1005	01/01/72	Present	36.7967	-108.4803	1643	24.2	73.9
Bloomfield	SLAMS	162 Highway 550 ; Bloomfield, NM	35-045-0009	08/01/77	Present	36.7421	-107.9773	1618	19.4	59.8
Navajo Lake	SLAMS	423 Highway 539 ; Navajo Lake, NM	35-045-0018	07/01/05	Present	36.8098	-107.6514	1950	49.3	56.4
Farmington	SLAMS	724 W Animas ; Farmington, NM	35-045-0006	08/01/77	Present	36.7273	-108.2152	1643	0.0	66.7
S.Ute 3 - Bondad	Tribal	7571 Highway 550 ; La Plata County, CO	08-067-7003	04/01/97	Present	37.1025	-107.8703	1920	50.5	19.3
S.Ute 1 - Ignacio	Tribal	County Road 517 ; La Plata County, CO	08-067-7001	06/01/82	Present	37.1389	-107.6317	1981	67.7	25.8
Shamrock Site	ARM-FS IMPROVE	8 mi. NE of Bayfield, CO	08-067-9000 SHMI1	02/01/04 08/01/04	Present Present	37.3038	-107.4842	2351	90.3	34.3
Mesa Verde	CASTNET IMPROVE SPMS NADP/NTN NADP/MDN	Chapin Mesa, Mesa Verde Nat'l Park, Montezuma County, CO	MEV405 MEVE 1 08-038-0101 CO99 CO99	01/10/95 03/05/94 07/23/06 04/28/81 12/26/01	Present Present Present Present Present	37.1984	-108.4907	2165	57.1	54.3
Pagosa Springs – School	SLAMS	309 Lewis St., Pagosa Springs, CO	08-007-0001	08/01/75	Present	37.2681	-107.0211	2168	121.9	74.8
Durango – Courthouse	SLAMS	1060 E. 2nd Ave., Durango, CO	08-067-1001	03/01/87	12/31/06	37.2739	-107.8786	1984	66.9	0.1
Durango – River City	SLAMS	1235 Camino del Rio, Durango, CO	08-067-0004	09/01/85	Present	37.2769	-107.8806	1985	66.8	0.3
Durango – Tradewinds	SLAMS	1455 S. Camino del Rio, Durango, CO	08-067-0009	10/30/03	04/06/05	37.2187	-107.8516	1973	63.1	3.9
Durango – Cutler	SLAMS	177 Cutler Dr., Durango, CO	08-067-0010	10/30/03	04/30/06	37.3082	-107.8456	1992	70.9	4.3
Durango – Grandview	SLAMS	56 Davidson Rd., Durango, CO	08-067-0011	07/01/04	12/31/06	37.2295	-107.8267	2044	67.6	6.8
Telluride	SLAMS	333 W. Colorado Ave., Telluride, CO	08-113-0004	03/01/90	Present	37.9375	-107.8117	2694	140.6	76.3
Durango Mt. Resort	Other	Hwy. 550 & Purgatory Drive	---	10/11/02	Present	37.6314	-107.8076	2665	105.1	38.9
Wolf Creek Pass	NADP/NTN	Mineral County, CO	CO91	05/26/92	Present	37.4686	-106.7903	3292	148.8	98.6
Molas Pass	NADP/NTN	San Juan County, CO	CO96	07/29/86	Present	37.7514	-107.6853	3249	121.2	56.4

Site	Program	Address	AQS / Other Code	Period of Record		Latitude	Longitude	Elevation (meters)	Distance from: (Km)	
				From	To				Farmington	Durango
Weminuche	IMPROVE	30 mi. N of Durango, CO	WEMI1	03/02/88	Present	37.6594	-107.7999	2750	110.6	44.0
San Pedro Parks	IMPROVE	6 mi E of Cuba, NM	SAPE1	08/15/00	Present	36.0139	-106.8447	2935	133.6	160.4
Fort Defiance	Tribal	Rte. 12 N, Bldg. F-004-051, Fort Defiance, AZ	04-001-1234	01/01/99	Present	35.7460	-109.0717	2090	135.4	200.4
Shiprock Dine College	Tribal	Dine College, GIS Lab, Shiprock, NM	35-045-1233	01/01/03	Present	36.8071	-108.6952	1525	45.0	141.1
Canyonlands NP	CASTNET NADP/NTN IMPROVE	"Island of the Sky" Visitor's Center, Canyonlands Nat'l Park, San Juan County, UT	CAN407 UT09 CANY1	01/24/95 11/11/97 03/02/88	Present Present Present	38.4580	-109.821	1814	239.8	214.6
Arches NP	IMPROVE	14 mi N of Moab, UT	ARCH1	03/02/88	05/16/92	38.7833	-109.5830	1722	253.6	217.2
Moab #6	SLAMS	168 West 400 North, Moab, UT	49-019-0006	10/21/93	6/30/03	38.5795	-109.5540			
Petrified Forest NP (Old)	CASTNET IMPROVE SPMS	1 mi. N of park HQ	PET427 PEFO1 04-001-0012	? 03/02/88 10/27/86	Present Present 04/16/92	35.0772	-109.7697	1766	262.9	329.2
Petrified Forest NP (New)	SPMS	SW Entrance; off Rte. 180	04-017-0119	01/01/88	Present	34.8230	-109.8919	1723	265.5	331.5
Rainbow Forest NP	NADP/NTN	Apache County, AZ	AZ97	12/03/02	Present	35.0013	-109.0128	1707	207.5	274.1
Alamosa	NADP/NTN	Alamosa county, CO	CO00	04/22/80	Present	37.4414	-105.8653	2298	221.0	177.6
Great Sand Dunes NP	IMPROVE	Monument HQ, Saguache County, CO	GRSA1	05/04/88	Present	37.7249	-105.5185	2498	258.0	207.1
Big Horn	RAWS	Conejos County, CO	BHRC2	05/13/93	Present	37.0208	-106.2011	2637	175	147
Sand Dunes	RAWS	Alamosa County, CO	SDNC2	06/02/04	Present	37.7267	-105.5108	2537	254	210
Lujan	RAWS	Saguache County, CO	LUJC2	09/13/94	Present	38.2544	-106.5678	3400	214	155
Needle Creek	RAWS	Saguache County, CO	NCKC2	09/05/02	Present	38.3894	-106.5308	2741	227	168
Huntsman Mesa	RAWS	Gunnison County, CO	HMEC2	05/22/91	Present	38.3319	-107.0889	2865	195	135
McClure Pass	RAWS	Gunnison County, CO	MPRC2	06/11/85	Present	39.1267	-107.2842	2761	264	205
Taylor Park	RAWS	Gunnison County, CO	TAPC2	10/27/87	Present	38.9086	-106.6028	3200	268	210
PSF2 Salida 555	RAWS	Chaffee County, CO	SIDC2	05/01/97	Present	38.7856	-105.9569	2932	291	229
Red Deer	RAWS	Chaffee County, CO	RDKC2	05/01/83	Present	38.8272	-106.2117	2660	280	218
Jay	RAWS	Delta County, CO	JAYC2	07/09/84	Present	38.8456	-107.7386	1890	227	168
Blue Park	RAWS	Mineral County, CO	BLPC2	04/24/90	Present	37.7931	-106.7786	3179	167	109
Black Canyon	RAWS	Montrose County, CO	LPRC2	06/04/97	Present	38.5428	-107.6869	2609	195	132
Carpenter Ridge	RAWS	Montrose County, CO	CPTC2	12/17/98	Present	38.4594	-109.0469	2465	195	160
Cottonwood Basin	RAWS	Montrose County, CO	CMEC2	05/23/91	Present	38.5731	-108.2778	2201	194	140

Site	Program	Address	AQS / Other Code	Period of Record		Latitude	Longitude	Elevation (meters)	Distance from: (Km)	
				From	To				Farmington	Durango
Nucla	RAWS	Montrose County, CO	NUCC2	05/21/98	Present	38.2333	-108.5617	1786	162	116
Sanborn Park	RAWS	Montrose County, CO	SPKC2	01/29/85	Present	38.1922	-108.2169	2417	153	101
Salter	RAWS	Dolores County, CO	SAWC2	05/30/85	Present	37.6511	-108.5369	2500	101	67
Devil Mtn.	RAWS	Archuleta County, CO	DYKC2	07/27/89	Present	37.2269	-107.3053	2274	92	50
Sandoval Mesa	RAWS	Archuleta County, CO	SDVC2	07/15/99	Present	37.0994	-107.3028	2588	86	53
Big Bear Park	RAWS	La Plata County, CO	BBRC2	08/26/05	Present	37.4961	-107.7294	3170	90	28
Mesa Mtn.	RAWS	La Plata County, CO	MMRC2	11/17/93	Present	37.0564	-107.7086	2249	54	25
SJF1 Durango 555	RAWS	La Plata County, CO	DUFC2	06/01/96	Present	37.3517	-107.9000	2502	72	9
Chapin	RAWS	Montezuma County, CO	CHAC2	09/07/99	Present	37.1994	-108.4892	2172	55	51
Mockingbird	RAWS	Montezuma County, CO	MOKC2	08/24/05	Present	37.4744	-108.8842	1957	99	87
Morefield	RAWS	Montezuma County, CO	MRFC2	11/12/99	Present	37.2972	-108.4128	2383	61	45
Albino Canyon	RAWS	San Juan County, NM	CWRN5	09/27/83	Present	36.9769	-107.6283	2182	55	35
Washington Pass	RAWS	San Juan County, NM	WPSN5	11/19/03	Present	36.0781	-108.8575	2856	86	147
Coyote	RAWS	Rio Arriba County, NM	COYN5	08/07/96	Present	36.0667	-106.6472	2682	149	161
Deadman Peak	RAWS	Rio Arriba County, NM	DPKN5	05/23/00	Present	36.4231	-107.7719	2575	46	129
Dulce #2	RAWS	Rio Arriba County, NM	DLCN5	07/07/05	Present	36.9350	-107.0000	2070	107	79
Jarita Mesa	RAWS	Rio Arriba County, NM	JARN5	04/15/02	Present	36.5558	-106.1031	2683	183	168
Stone Lake	RAWS	Rio Arriba County, NM	STLN5	07/07/05	Present	36.7314	-106.8647	2268	115	103
Zuni Buttes	RAWS	McKinley County, NM	ZNRN5	04/04/06	Present	35.1392	-108.9414	2039	172	236
Alb Portable #2	RAWS	McKinley County, NM	TSO43	11/18/03	Present	35.5264	-107.3211	2481	138	182
Bryson Canyon	RAWS	Grand County, UT	BCRU1	09/03/87	Present	39.2789	-109.2211	1621	283	241
Big Indian Valle	RAWS	San Juan County, UT	BIVU1	09/02/87	Present	38.2244	-109.2783	2121	182	153
Kane Gulch	RAWS	San Juan County, UT	KAGU1	06/20/91	Present	37.5247	-109.8931	1981	165	174
North Long Point	RAWS	San Juan County, UT	NLPU1	08/13/97	Present	37.8547	-109.8389	2646	182	175
Piney Hill	RAWS	Apache County, AZ	QPHA3	11/19/03	Present	35.7611	-109.1675	2469	126	187
Cortez	CoAgMet	9 mi. SW of Cortez, CO	CTZ01	04/24/91	Present	37.2248	-108.6730	1833	67	67
Dove Creek	CoAgMet	4 mi. NW of Dove Creek	DVC01	10/28/92	Present	37.7265	-108.9540	2010	123	104
Towaoc	CoAgMet	Ute Mtn Ute Farm	TWC01	06/30/98	Present	37.1891	-108.9350	1621	78	88
Yellow Jacket	CoAgMet	2.5 mi. NW of Yellow Jacket	YJK01	05/19/91	Present	37.5289	-108.7240	2103	94	77
Yucca House	CoAgMet	Yucca House National Monument	YUC01	01/01/02	Present	37.2478	-108.6870	1821	69	67
Cortez-Montezuma County Airport	NWS	3 mi. SW of Cortez, CO	KCEZ	01/01/97	Present	37.3064	-108.6256	1803	71	7

Site	Program	Address	AQS / Other Code	Period of Record		Latitude	Longitude	Elevation (meters)	Distance from: (Km)	
				From	To				Farmington	Durango
Cottonwood Pass	NWS	SW of Buena Vista, CO	K7BM	11/17/04	Present	38.7825	-106.2181	2995	280	215
Durango-La Plata County Airport	NWS	1000 Airport Road; Durango, CO	KDRO	01/01/97	Present	37.1431	-107.7597	2038	60	0
Gunnison-Crested Butte Regional Airport	NWS	519 W Rio Grande; Gunnison, CO	KGUC	01/01/97	Present	38.5333	-106.9333	2340	221	156
Montrose Regional Airport	NWS	2100 Airport Road ; Montrose, CO	KMTJ	01/01/97	Present	38.5050	-107.8975	1755	189	128
Pagosa Springs, Wolf Creek Pass	NWS	NE of Pagosa Springs, CO	KCPW	11/11/03	Present	37.4514	-106.8003	3584	145	95
Saguache Municipal Airport	NWS	2 mi. NW of Saguache, CO	04V	11/17/04	Present	38.0972	-106.1686	2385	227	171
Salida Mountain, Monarch Pass	NWS	W of Salida, CO	KMYP	09/10/03	Present	38.4844	-106.3169	3667	249	185
Telluride Regional Airport	NWS	1500 Last Dollar Road ; Telluride, CO	KTEX	02/05/97	Present	37.9539	-107.9086	2767	135	72
Farmington, Four Corners Regional Airport	NWS	800 Municipal Drive ; Farmington, NM	KFMN	01/01/97	Present	36.7436	-108.2292	1677	0	63
Grants-Milan Municipal Airport	NWS	3 mi. NW of Grants, NM	KGNT	04/11/97	Present	35.1653	-107.9022	1988	160	214
Gallup Municipal Airport	NWS	2111 W Hwy 66 ; Gallup, NM	KGUP	01/01/97	Present	35.5111	-108.7894	1973	133	194
Window Rock Airport	NWS	1 mi. S of Window Rock AZ	KRQE	11/14/99	Present	35.6500	-109.0667	2055	131	190
Moab, Canyonlands Field	NWS	18 mi. NW of Moab, UT	KCNY	01/01/97	Present	38.7600	-109.7447	1388	249	224

ARM-FS : Air Resource Management, USDA Forest Service
CASTNET : Clean Air Status and Trends Network, EPA
CoAgMet : Colorado Agricultural Meteorological Network
IMPROVE : Interagency Monitoring of Protected Visual Environments
NADP/NTN : National Atmospheric Deposition Program, National Trends Network
NADP/MDN : National Atmospheric Deposition Program, Mercury Deposition Network
NWS : National Weather Service
RAWS : Remote Automated Weather Stations
SLAMS : State/Local Air Monitoring Stations
SPMS : Special Purpose Monitoring Stations
Tribal : Tribal Jurisdiction

Criteria Pollutant Sites

Site	Program	Criteria Pollutants							
		O3	SO2	CO	NOx	NO	NO2	PM10	PM2.5
Substation	SLAMS	h	h		h	h	h		
Bloomfield	SLAMS	h	h		h	h	h		
Navajo Lake	SLAMS	h			h	h	h		h
Farmington	SLAMS							1d/6d	1d/3d
S.Ute 3 - Bondad	Tribal	h			h	h	h	ended 9/30/06	
S.Ute 1 - Ignacio	Tribal	h		h	h	h	h	ended 9/30/06	
Shamrock Site	ARM-FS IMPROVE	h	1d/3d		h 1d/3d	h	h	1d/3d	1d/3d
Mesa Verde	CASTNET IMPROVE SPMS NADP/NTN ADP/MDN	h	h 1d/3d		h 1d/3d			1d/3d	1d/3d
Pagosa Springs – School	SLAMS							1d/1d	1d/3d end 12/06
Durango – Courthouse	SLAMS							1d/3d end 12/06	
Durango- River City	SLAMS							1d/3d	
Durango – Tradewinds	SLAMS							1d/6d end 3/05	
Durango – Cutler	SLAMS							1d/6d end 4/06	
Durango - Grandview	SLAMS							1d/3d end 12/06	
Telluride	SLAMS							1d/3d	1d/3d end 12/06
Durango Mt. Resort	Other							h	
Weminuche	IMPROVE							1d/3d	1d/3d
San Pedro Parks	IMPROVE							1d/3d	1d/3d
Fort Defiance	Tribal							1d/6d	
Shiprock Dine College	Tribal							1d/6d	
Canyonlands NP	CASTNET NADP/NTN IMPROVE	h	h 1d/3d		h 1d/3d			1d/3d	1d/3d
Arches NP	IMPROVE		1d/3d		1d/3d				
Moab #6	SLAMS							1d/6d	
Petrified Forest NP (Old)	CASTNET IMPROVE SPMS	h h	h 1d/3d		h 1d/3d			1d/3d	1d/3d
Petrified Forest NP (New)	SPMS	h							
Great Sand Dunes NP	IMPROVE							1d/3d	1d/3d

See Monitoring Site General Information table for abbreviations
h : Sampled and/or averaged hourly
1d/1d : 24-hour sample taken every day
1d/3d : 24-hour sample taken every 3rd day
1d/6d : 24-hour sample taken every 6th day

Meteorological Sites

Site	Program	Wind	Temp	Delta T	Solar	RH	Precip
Substation	SLAMS	h	h	h	h		
Bloomfield	SLAMS	h	h	h	h		
Navajo Lake	SLAMS	h	h	h	h		
S.Ute 3 - Bondad	Tribal	h	h	h	h	h	h
S.Ute 1 - Ignacio	Tribal	h	h	h	h	h	h
Shamrock Site	ARM-FS IMPROVE	h	h		h	h	h
Mesa Verde	CASTNET IMPROVE SPMS NADP/NTN NADP/MDN	h	h	h	h	h	
Durango Mt. Resort	Other	h	h	h	h	h	h
Fort Defiance	Tribal	h	h		h	h	h
Shiprock Dine College	Tribal	h	h		h	h	h
Canyonlands NP	CASTNET NADP/NTN IMPROVE	h	h	h	h	h	
Petrified Forest NP (Old)	CASTNET IMPROVE	h	h	h	h	h	
Petrified Forest NP (New)	SPMS	h	h				
Big Horn	RAWS	h	h		h	h	h
Sand Dunes	RAWS	h	h		h	h	h
Lujan	RAWS	h	h		h	h	h
Needle Creek	RAWS	h	h		h	h	h
Huntsman Mesa	RAWS	h	h		h	h	h
McClure Pass	RAWS	h	h		h	h	h
Taylor Park	RAWS	h	h		h	h	h
PSF2 Salida 555	RAWS	h	h		h	h	h
Red Deer	RAWS	h	h		h	h	h
Jay	RAWS	h	h		h	h	h
Blue Park	RAWS	h	h		h	h	h
Black Canyon	RAWS	h	h		h	h	h
Carpenter Ridge	RAWS	h	h		h	h	h
Cottonwood Basin	RAWS	h	h		h	h	h
Nucla	RAWS	h	h		h	h	h
Sanborn Park	RAWS	h	h		h	h	h
Salter	RAWS	h	h		h	h	h
Devil Mtn.	RAWS	h	h		h	h	h
Sandoval Mesa	RAWS	h	h		h	h	h
Big Bear Park	RAWS	h	h		h	h	h
Mesa Mtn.	RAWS	h	h		h	h	h
SJF1 Durango 555	RAWS	h	h		h	h	h
Chapin	RAWS	h	h		h	h	h
Mockingbird	RAWS	h	h		h	h	h
Morefield	RAWS	h	h		h	h	h

Site	Program	Wind	Temp	Delta T	Solar	RH	Precip
Albino Canyon	RAWS	h	h		h	h	h
Washington Pass	RAWS	h	h		h	h	h
Coyote	RAWS	h	h		h	h	h
Deadman Peak	RAWS	h	h		h	h	h
Dulce #2	RAWS	h	h		h	h	h
Jarita Mesa	RAWS	h	h		h	h	h
Stone Lake	RAWS	h	h		h	h	h
Zuni Buttes	RAWS	h	h		h	h	h
Alb Portable #2	RAWS	h	h		h	h	h
Bryson Canyon	RAWS	h	h		h	h	h
Big Indian Valle	RAWS	h	h		h	h	h
Kane Gulch	RAWS	h	h		h	h	h
North Long Point	RAWS	h	h		h	h	h
Piney Hill	RAWS	h	h		h	h	h
Cortez	CoAgMet	h	h		h	h	
Dove Creek	CoAgMet	h	h		h	h	
Towaoc	CoAgMet	h	h		h	h	
Yellow Jacket	CoAgMet	h	h		h	h	
Yucca House	CoAgMet	h	h		h	h	
Cortez-Montezuma County Airport	NWS	h	h			h	
Cottonwood Pass	NWS	h	h			h	
Durango-La Plata County Airport	NWS	h	h			h	
Gunnison-Crested Butte Regional Airport	NWS	h	h			h	
Montrose Regional Airport	NWS	h	h			h	
Pagosa Springs, Wolf Creek Pass	NWS	h	h			h	
Saguache Municipal Airport	NWS	h	h			h	
Salida Mountain, Monarch Pass	NWS	h	h			h	
Telluride Regional Airport	NWS	h	h			h	
Farmington, Four Corners Regional Airport	NWS	h	h			h	
Grants-Milan Municipal Airport	NWS	h	h			h	
Gallup Municipal Airport	NWS	h	h			h	
Window Rock Airport	NWS	h	h			h	
Moab, Canyonlands Field	NWS	h	h			h	

See Monitoring Site General Information table for abbreviations
h: Sampled and/or averaged hourly

Deposition Sites

Site	Program	Deposition								
		NH3	pH	SO4	NH4	NO3	Pb	HF	Hg	Ca, Mg, K, Na, Cl
Substation	SLAMS	3w								
Navajo Lake	SLAMS	3w								
S.Ute 3 - Bondad	Tribal	3w								
Mesa Verde	CASTNET IMPROVE SPMS NADP/NTN NADP/MDN	3w	w	w	w	w			w	w w
Wolf Creek Pass	NADP/NTN		w	w	w	w				w
Molas Pass	NADP/NTN		w	w	w	w				w
Canyonlands NP	CASTNET NADP/NTN IMPROVE		w	w	w	w				w
Rainbow Forest NP	NADP/NTN		w	w	w	w				w
Alamosa	NADP/NTN		w	w	w	w				w
Farmington Airport	OTHER	3w								

See Monitoring Site General Information table for abbreviations
w : Sampled weekly
3w : Sampled every 3 weeks

DATA ANALYSIS AND RECOMMENDATIONS

Meteorology and Wind Roses

Background:

Rationale and Benefits:
Meteorology is the science that deals with the study of the atmosphere and its phenomena, especially with weather and weather forecasting. Meteorological conditions are a driving force in many bad pollution events and situations. These include stagnation, inversions and blowing dust. There are a number of components to meteorology, including wind speed, wind direction, temperature, relative humidity, barometric pressure, solar radiation, precipitation and others. Modeling is performed with the various components as part of forecasting for weather conditions as well as for air pollution impacts.

For air pollution, wind speed and wind direction are two of the more important components. These can determine how far pollution can be transported in a certain time period, if stagnation periods exist and what sources may have contributed to the air pollution. Wind roses are a simple visual way to depict wind speed strengths as a function of wind direction for a period of time. Wind roses are based on the direction that the wind is blowing from. Another way of visualizing a wind rose is to picture yourself standing in the center of the plot and facing into the wind. The wind direction is broken down in the 16 cardinal directions (i.e. N, NNE, NE, ENE, E, ESE, SE, SSE, S, etc). The wind speed is broken down into multiple ranges. The length of each arm of the wind rose represents the percentage of time the wind was blowing from that direction. The longer the arm, the greater percentage of time the wind is blowing from that direction. Since the occurrence of wind speeds of different ranges from a particular direction are stacked on the radius in order of increasing speeds, one must compare the length of each color to the distance between the percent circles to get the percent of time each range of wind speed occurred. The circles representing the percent of time can vary from rose to rose hence each rose must be checked for the values. Wind roses can be generated by a number of commercially available software programs. For this analysis, WRPLOT View from Lakes Environmental Software was employed.[1]

Existing meteorological data for the Four Corners region:
Meteorological data are collected at a number of different locations in the Four Corners region. Sites include State and Tribal agencies, the National Weather Service (NWS), the U.S. Forest Service (USFS), the National Park Service (NPS), The Remote Automated Weather Stations (RAWS) network, the Colorado Agriculture Meteorological Network (CoAgMet) and other private groups. Data are available from varying sources, including the U.S. Environmental Protection Agency's Air Quality System[2], the CoAgMet website[3], the New Mexico Environment Department website[4], the NWS website[5], the RAWS website[6] and from direct contact. For wind roses, hourly data (or more frequent) are needed. Ten-meter tall towers are a general standard that is used, though not all networks are set up this way. Maps of the meteorological sites that were used in this analysis are presented below, both for the whole Four Corners region and for a core area. These sites are a limited subset of the total number of possible sites, as can be seen in the site matrix tables in a different section of this overall report.

Wind roses were developed using hourly wind speed and wind direction data from 2006. Annual wind roses were developed as well at daytime (6:00 a.m. – 6:00 p.m.) and nighttime (6:00 p.m. – 6:00 a.m.). These wind roses were then overlaid on both political boundary maps and topographical maps (see annual/daytime/nighttime wind rose maps).

In looking at the annual wind roses, it is evident that some sites are more influenced by local topography than others. An example is the Cortez CoAgMet site, which is located in the valley between Sleeping Ute Mountain and Mesa Verde and is subjected to definite channeling effects. Another example is the U.S. Forest Service Shamrock site, which is located on the side of a hogback ridge. It can also be seen that the strongest winds are generally from a more westerly direction than an easterly one. From the daytime wind roses, there are general westerly or northerly/southerly components to the winds. In comparison, the nighttime wind roses show more of general easterly to northerly components. These trends are expected based on prevailing regional wind patterns as well as more local convection heating and cooling patterns along with topography.

These wind roses can be broken down even further, such as only for summer afternoon periods when ozone levels are expected to be highest (see summer afternoon wind rose maps). These wind roses show, in general, a predominant westerly to southwesterly component. As mentioned previously, some sites still exhibit wind patterns that are strongly influenced by local topography rather than more regional winds. However, these types of plots are useful in describing what may happen with air pollution flows during different periods of time. While not performed for this analysis, additional seasonal plots could be dome, such as for winter when inversions are more prevalent.

Data Gaps:
No significant data gaps exist for meteorological monitoring in the Four Corners region, with the exception of southwestern Utah and northeastern Arizona.

Suggestions for Future Monitoring Work:
No suggestions for additional monitoring of meteorological parameters are currently being proposed.

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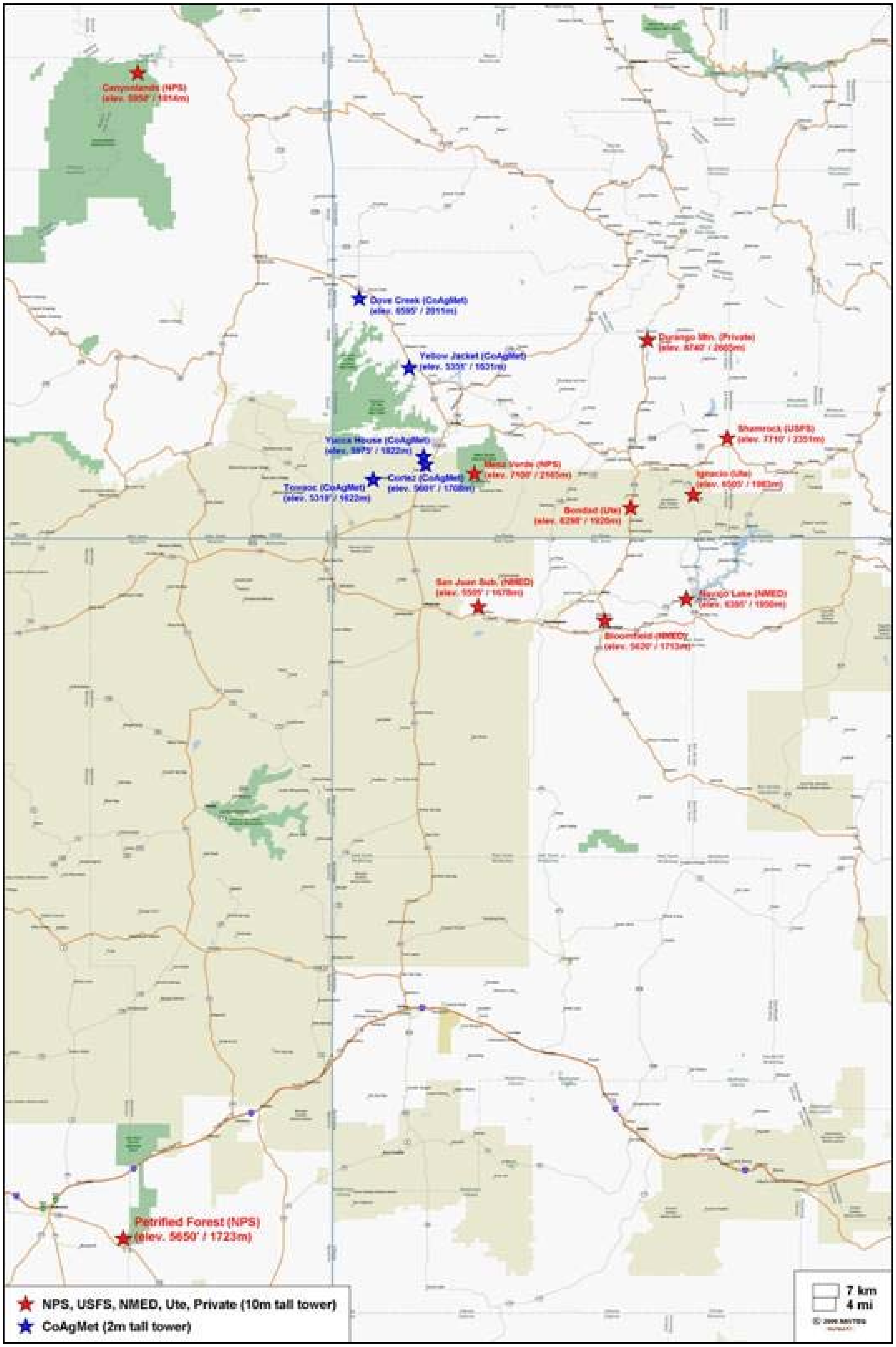
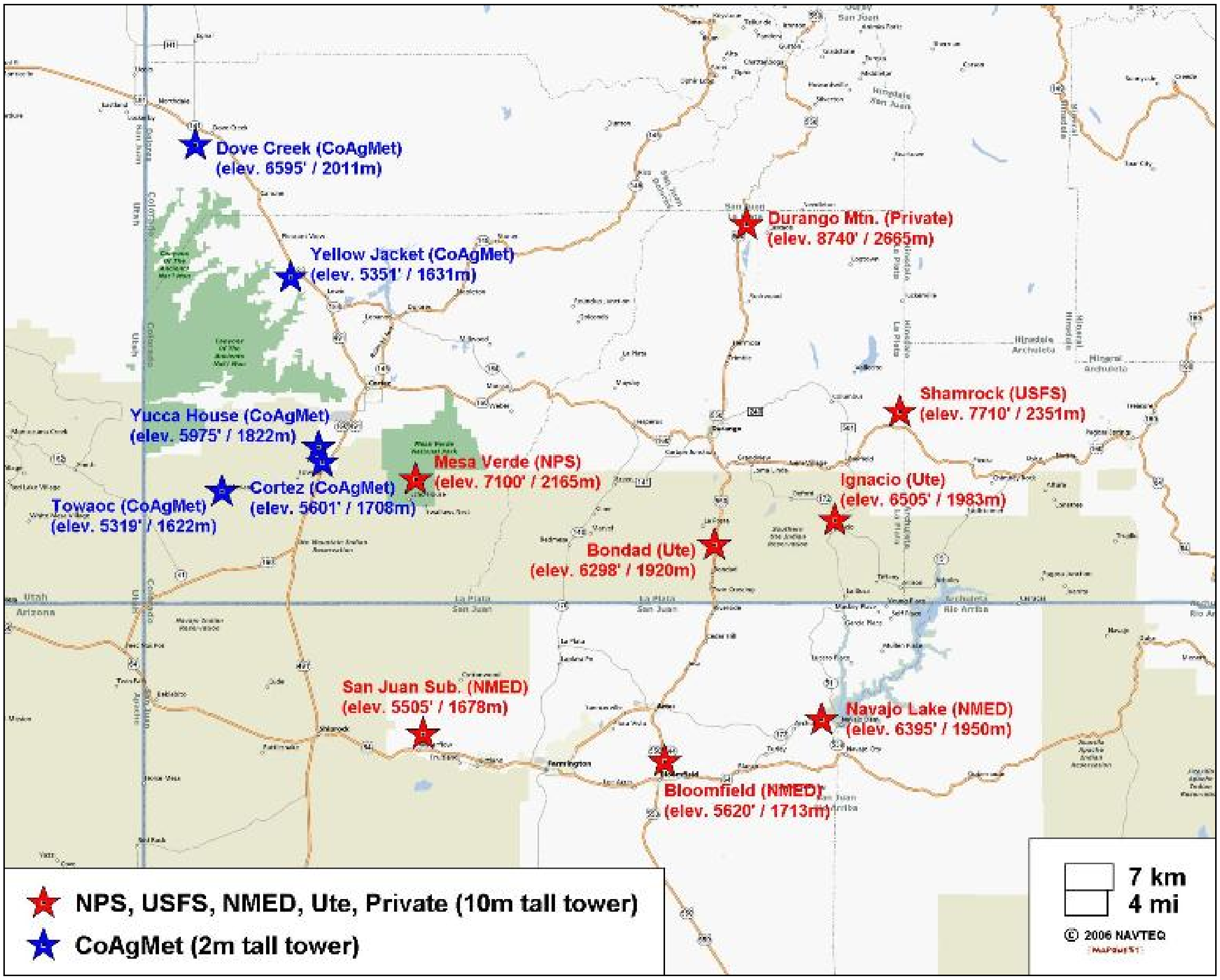
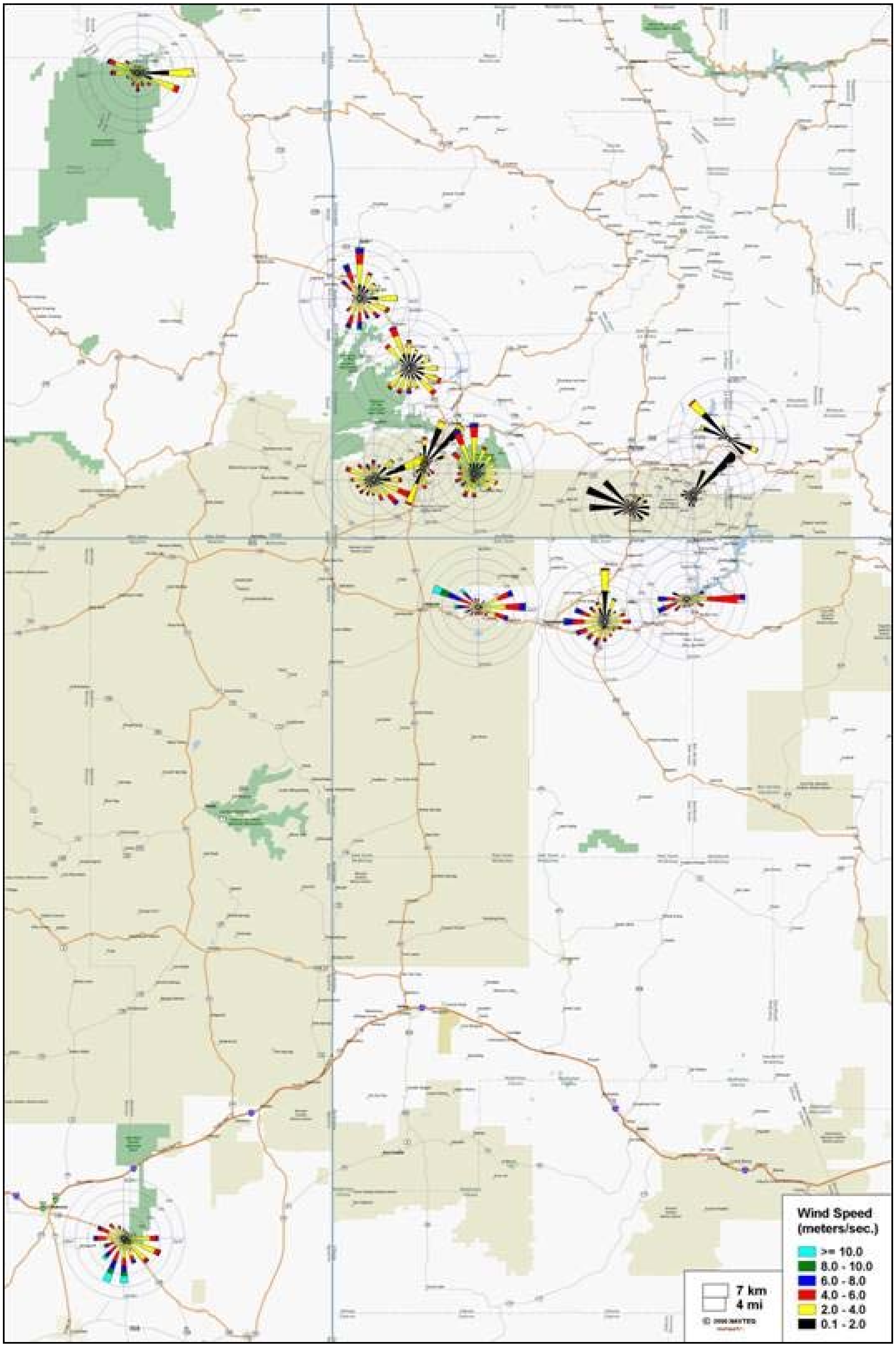
Four Corners --- Meteorological Sites in 2006



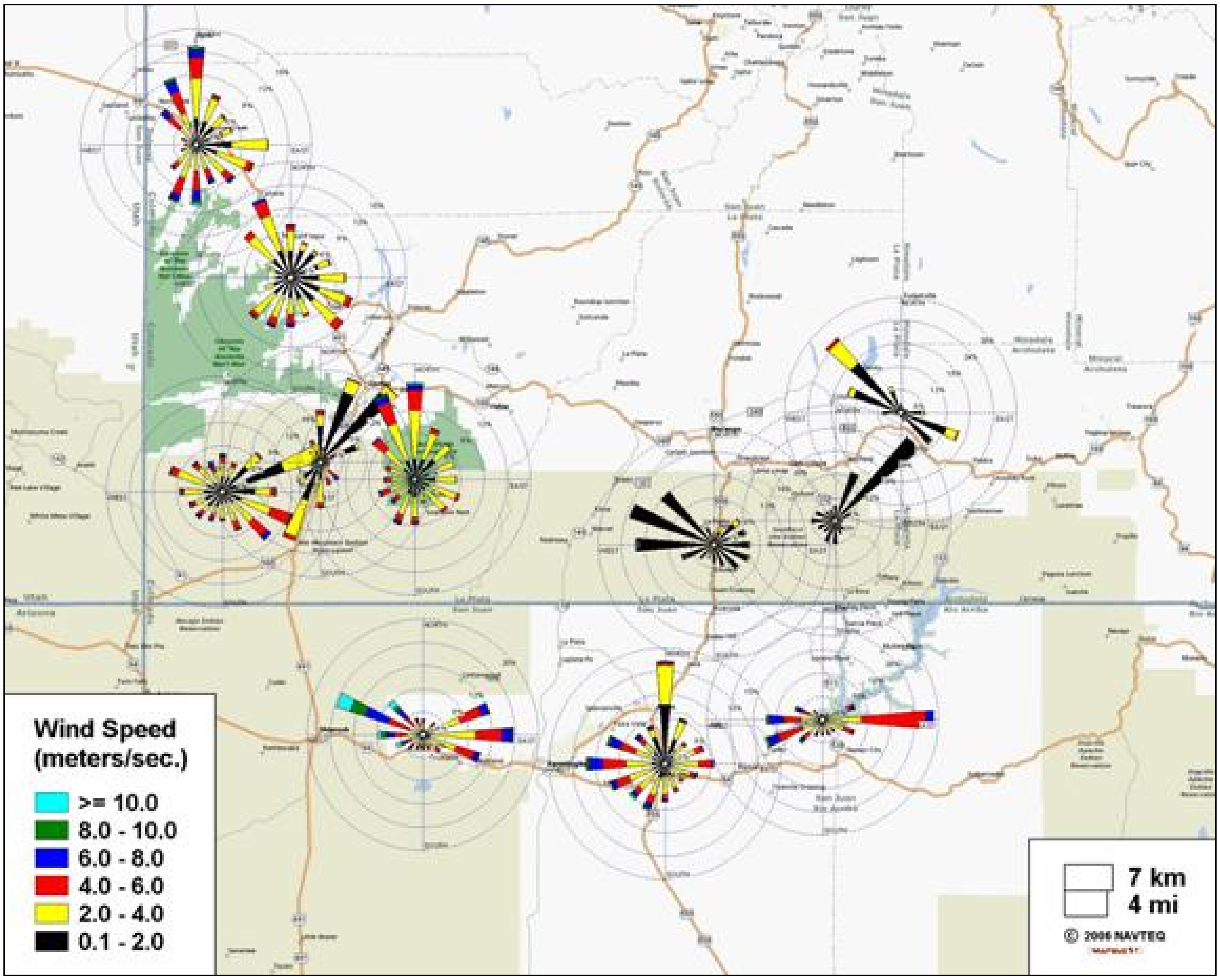
Close-in Four Corners --- Meteorological Sites in 2006



Four Corners --- 2006 Annual Wind Roses



Close-in Four Corners --- 2006 Annual Wind Roses
(Political boundary map)



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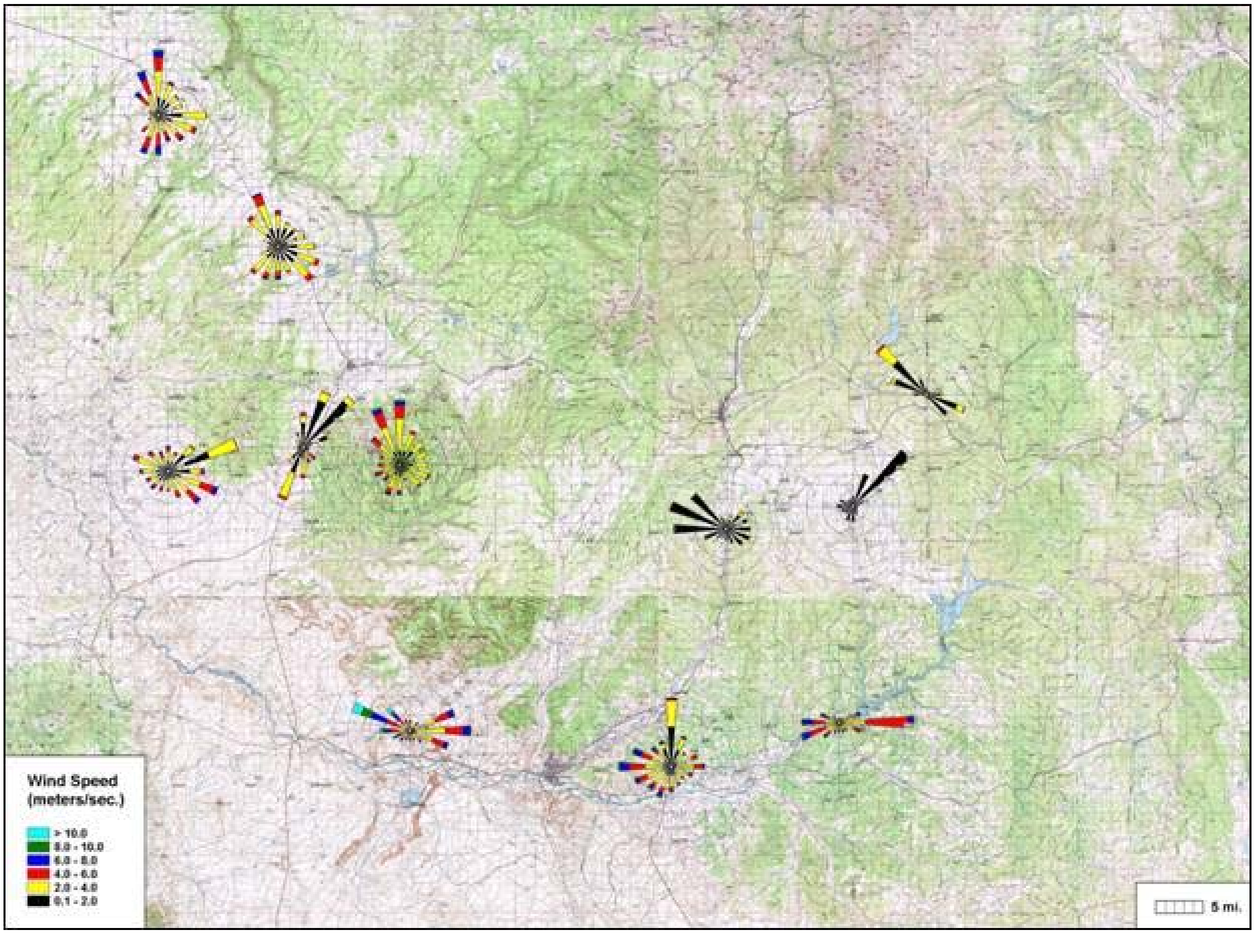
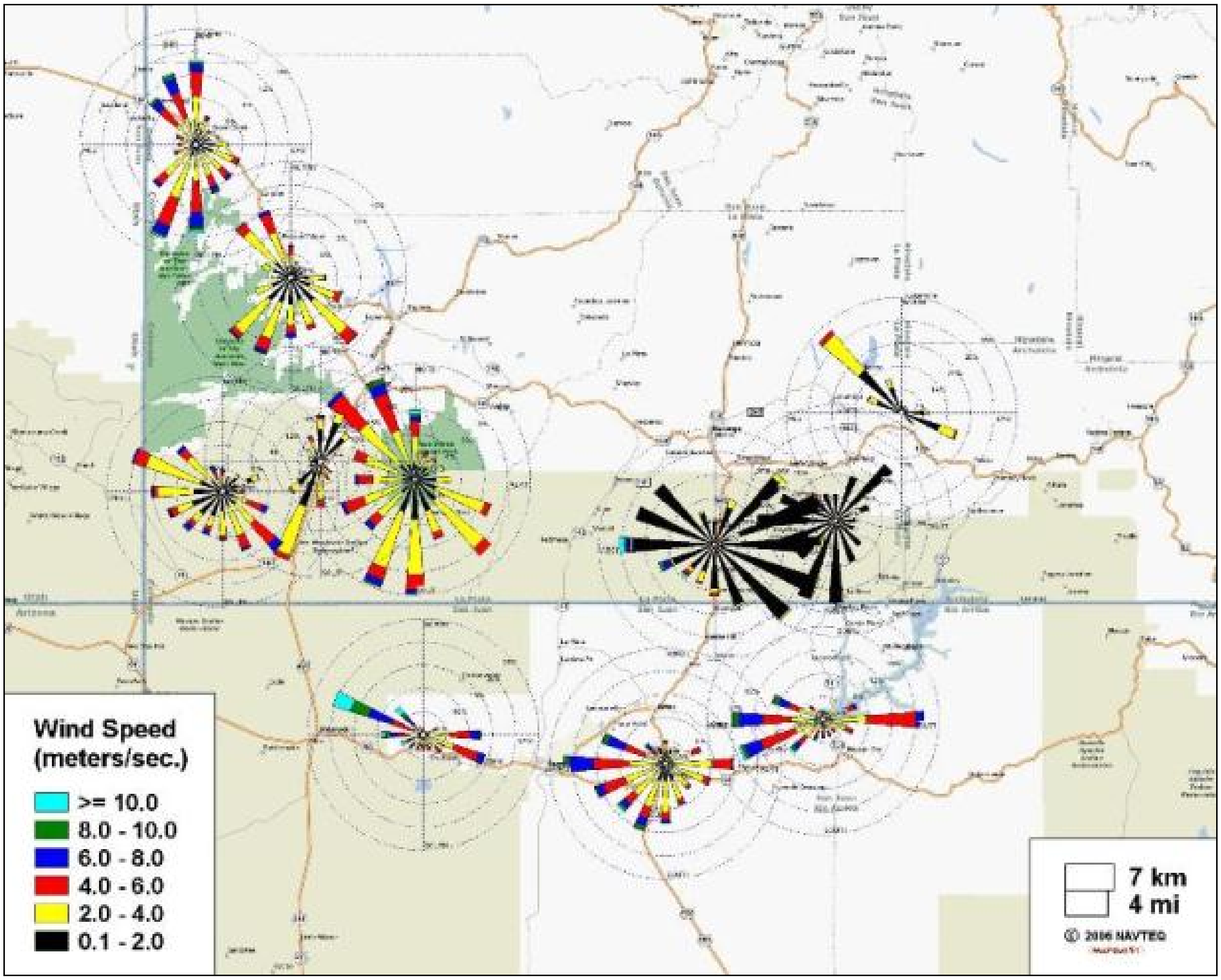
(Topographic map)



Close-in Four Corners --- 2006 Daytime Wind Roses
(Political boundary map)



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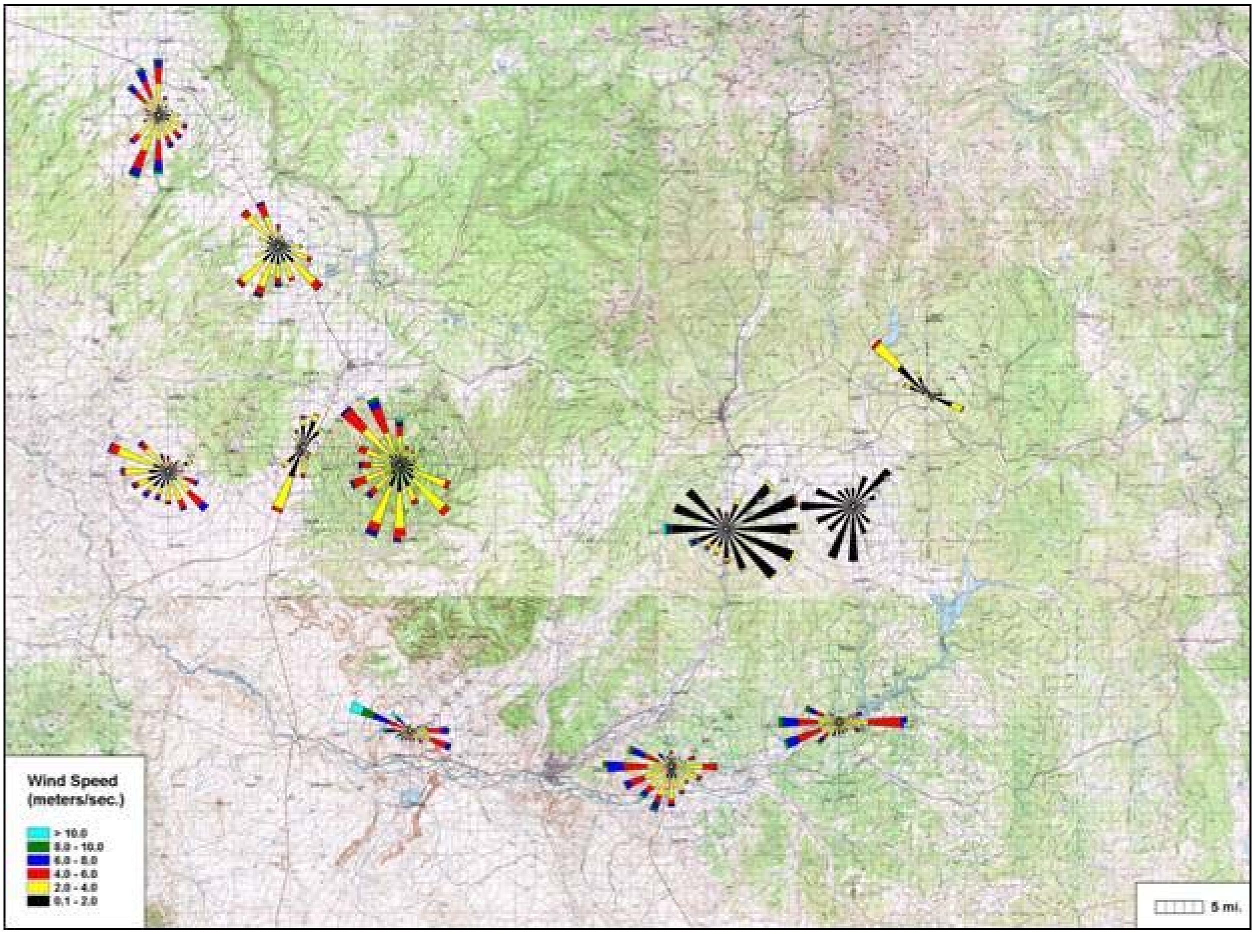
(Topographic map)



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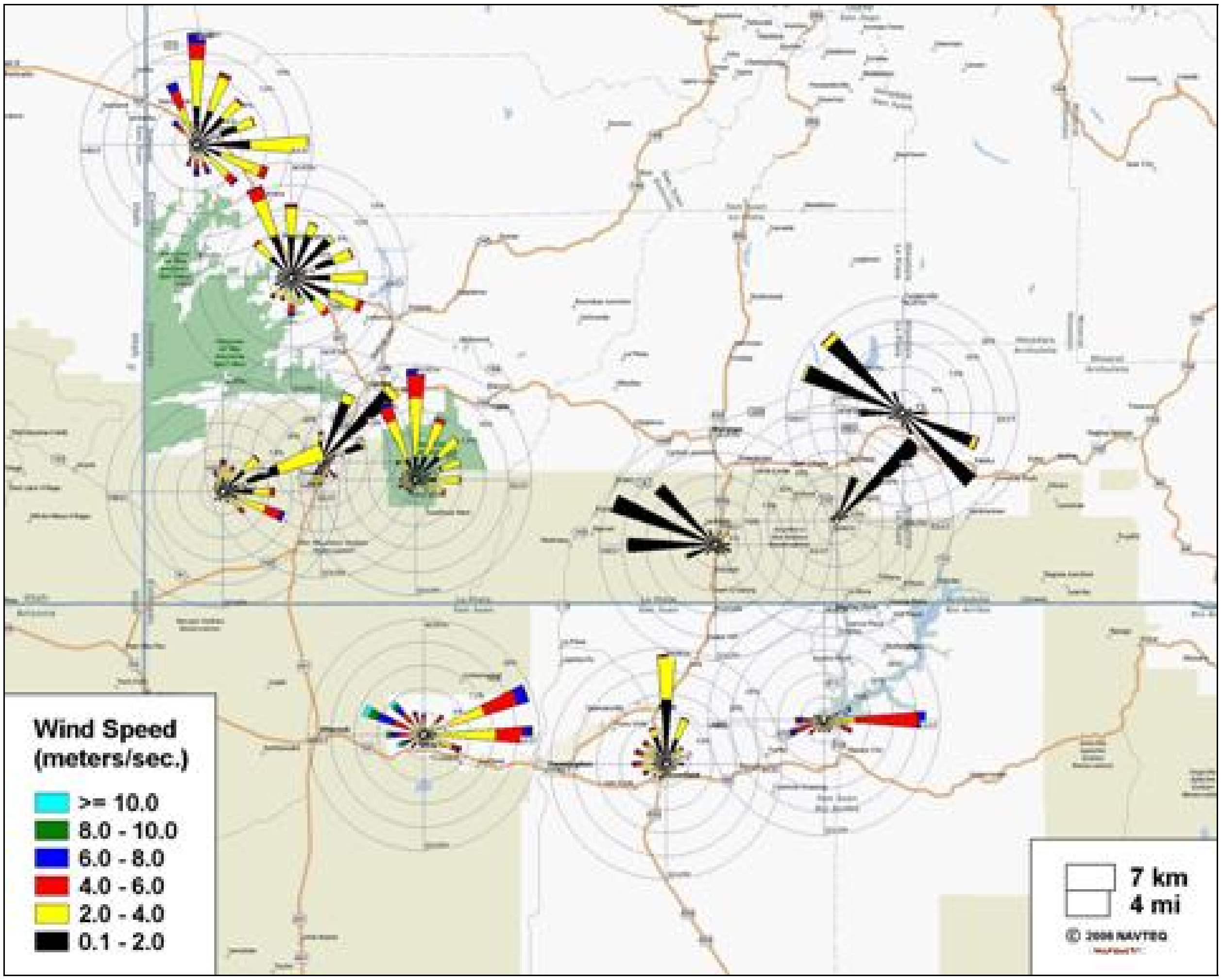
(Political boundary map)



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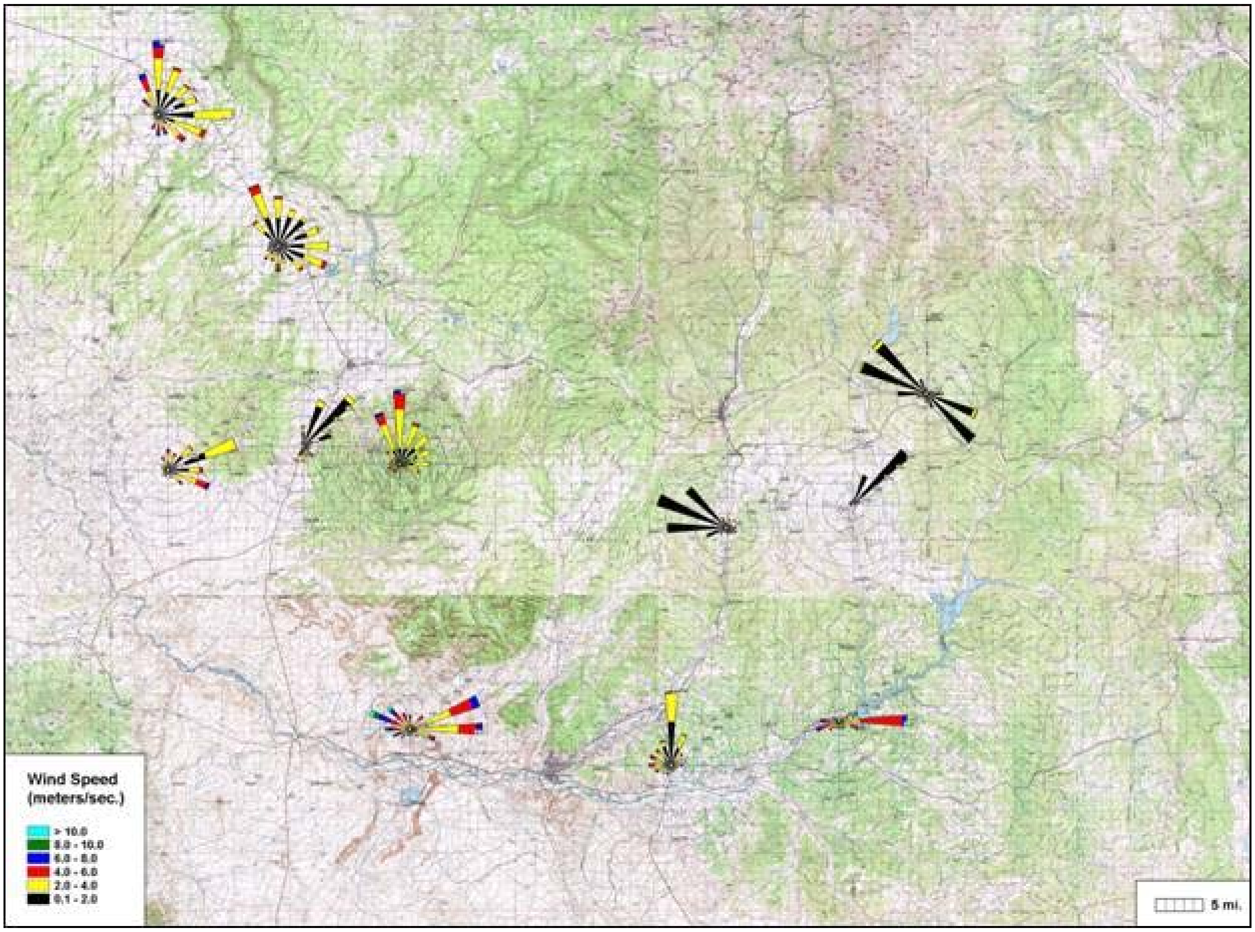
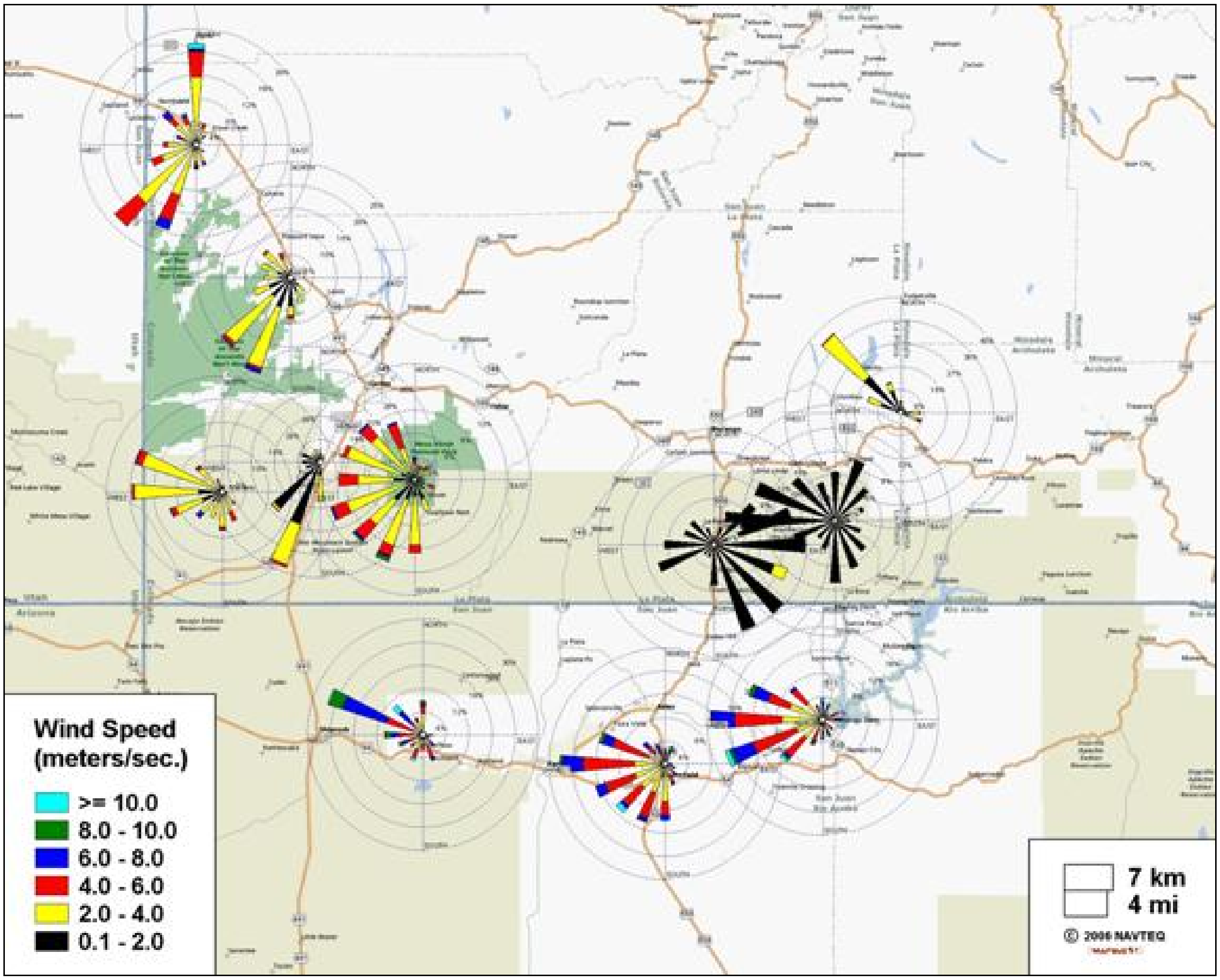
(Topographic map)



Close-in Four Corners --- 2006 Summer Afternoon Wind Roses
(Political boundary map)



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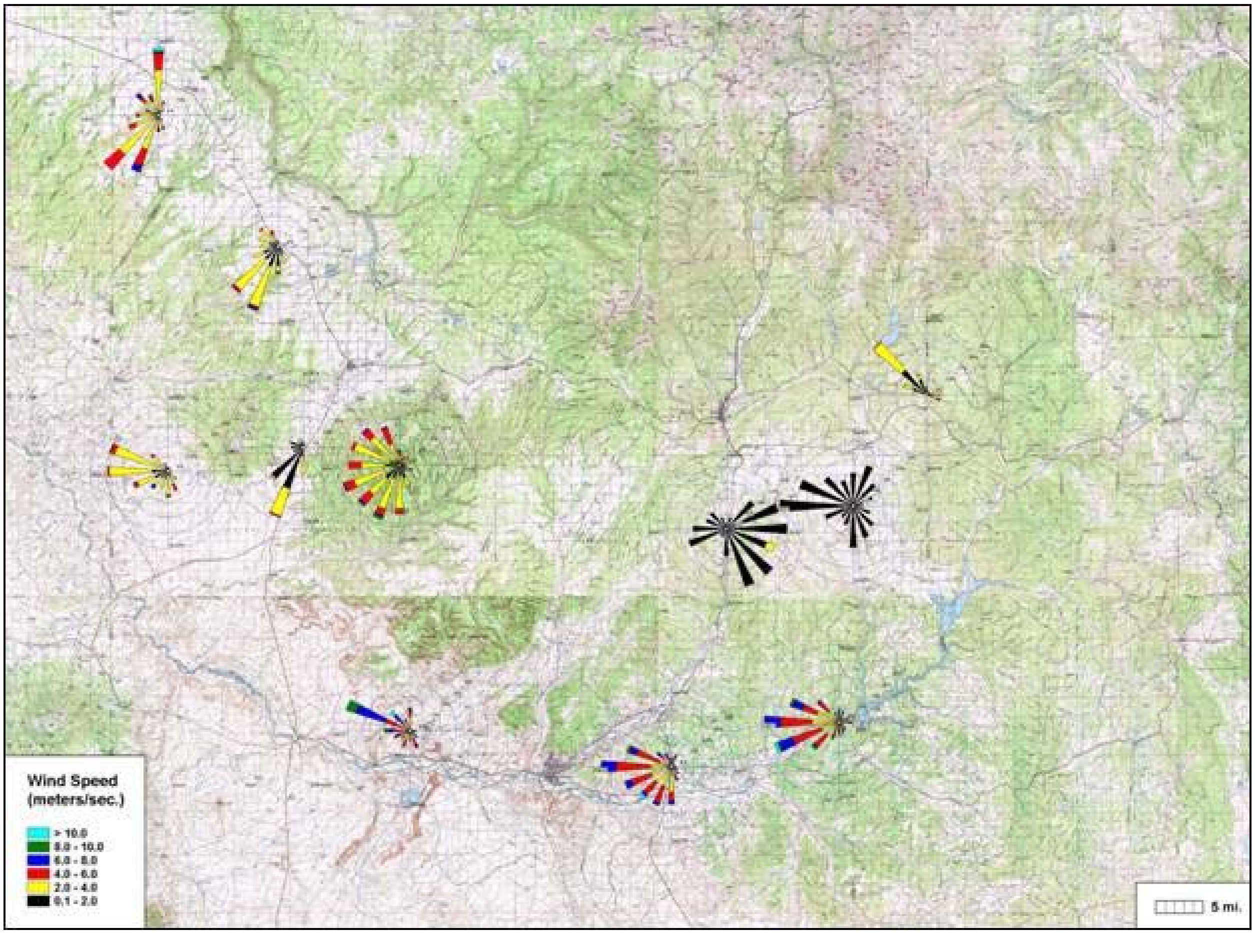
(Topographic map)



Ozone and Precursor Gases

Background:

Rationale and Benefits:
Ozone is a colorless, odorless and tasteless gaseous pollutant that is both necessary and harmful to human health. In the stratosphere where it occurs naturally, it provides a barrier to ultraviolet radiation. However, at ground-level in the troposphere, ozone is the prime ingredient of smog. When inhaled, ozone can cause acute respiratory problems, aggravate asthma, cause significant temporary decreases in lung capacity, cause inflammation of lung tissue, impair the body's immune system defenses and lead to hospital admissions and emergency room visits.[1] In addition, ground-level ozone ruptures the cells of green leaves, thereby interfering with the ability of plants to produce and store food, so that growth, reproduction and overall plant health are compromised.

Generally, ozone is a secondary-formation pollutant in the troposphere. That is, ozone is not emitted directly into the air, but is formed from precursor gases called oxides of nitrogen (NOx) and volatile organic compounds (VOCs) that in the presence of heat and sunlight react to form ozone.[1] Thus, ozone is generally an afternoon, summertime issue. Due to the process in which it is formed, however, high ozone levels typically do not occur in the area where the precursor gases are emitted, but may be a few to hundreds of miles away (depending on the meteorology). This means that ozone can be both a regional and a local concern.

VOCs and NOx, the ozone precursor gases, are emitted from both man-made sources (i.e. combustion, oil and gas development, etc.) and natural sources (i.e. plants, forest fires, etc.). VOC's that specifically can lead to ozone formation are generally called non-methane organic compounds (NMOCs) and do not include chlorinated compounds. In general, alkenes, aromatic hydrocarbons and carbonyls have a high ozone formation potential (higher incremental reactivity) while alkanes have a lower potential.[2] NOx primarily consists of nitric oxide (NO) and nitrogen dioxide (NO_2). NO_2, like ozone, is designated as a "criteria" pollutant that has a health-based National Ambient Air Quality Standard (NAAQS).

The NAAQS for ozone is set at a level of 0.08 parts per million for the three-year average of the annual fourth-maximum 8-hour values. However, the Clean Air Scientific Advisory Committee (CASAC) is currently recommending that the standard be reduced to a level in the range of 0.060 to 0.070 parts per million.[3] The NAAQS for NO_2 is set at 0.053 parts per million for an annual average.

Existing ozone data for the Four Corners region:
Ground level ozone is currently monitored on a continuous basis at nine locations in the Four Corners region, with seven sites being in a core area (see ozone sites maps). Two other sites in the region previously monitored for ozone. For regulatory comparisons to the NAAQS, continuous analyzers that have been designated as "equivalent' or "reference" by the U.S. Environmental Protection Agency (EPA) are used. In Colorado, current monitoring is performed at Mesa Verde National Park, two Southern Ute Tribe sites and at the U.S. Forest Service (USFS) Shamrock site near Bayfield. In New Mexico, monitoring is performed at three New Mexico Environment Department (NMED) sites near the San Juan power plant, Bloomfield and Navajo Lake. A Navajo Nation site in Shiprock, NM is planned to commence operation by the end of 2007. The closest site in Arizona is located at Petrified Forest National Park and the closest site in Utah is at Canyonlands National Park. With the exception of the USFS Shamrock site, all of the data are available on EPA's Air Quality System.[4]

Currently, ambient ozone levels in the Four Corners region are below the level of the current NAAQS (see trends and standards graphs). However, at Mesa Verde and one Southern Ute site there is an increasing trend, and the two newer sites (USFS, Navajo Lake) are recording higher levels. Many of the sites would be above the level of a reduced NAAQS, as proposed by CASAC.

In addition, in 2003, EPA conducted a passive ozone monitoring study in the area as part of a Region 6 ozone gap study. Seven passive ozone monitoring sites were established in San Juan County in New Mexico.[5] The data showed significantly high ozone concentrations in the western and northeastern areas of San Juan County, New Mexico, in addition to the high ozone concentrations already found in the north central area of the County.[6]

Pollutant roses were developed to help provide ideas on where ozone precursor sources may come from and where high ozone concentrations may be found. Pollutant roses, like wind roses, are a simple visual way to depict pollutant concentrations as a function of wind direction for a period of time. Pollutant roses are based on the direction that the wind is blowing from. Another way of visualizing a pollutant rose is to picture yourself standing in the center of the plot and facing into the wind. The wind direction is broken down in the 16 cardinal directions (i.e. N, NNE, NE, ENE, E, ESE, SE, SSE, S, etc). The pollutant concentration is broken down into multiple ranges. The length of each arm of the pollutant rose represents the percentage of time the wind was blowing from that direction. The longer the arm, the greater percentage of time the wind is blowing from that direction. Since the occurrence of pollutant concentrations of different ranges from a particular direction are stacked on the radius in order of increasing speeds, one must compare the length of each color to the distance between the percent circles to get the percent of time each range of pollutant concentration occurred. The circles representing the percent of time can vary from rose to rose hence each rose must be checked for the values. Pollutant roses can be generated by a number of commercially available software programs. For this analysis, WRPLOT View from Lakes Environmental Software was employed.[8]

With ozone typically having peak concentrations in the summer afternoons when sunlight is strongest, pollutant roses were developed accordingly and were placed on both political boundary and topographic base maps (see pollutant rose maps). As can be seen from these pollutant rose maps, ozone at the three southern core area sites in New Mexico and the Mesa Verde site in Colorado show predominantly westerly wind directions in this summer afternoon timeframe. This generally mirrors the predominant San Juan River drainage. The two Southern Ute Tribe sites and the Forest Service Shamrock site appear to be heavily influenced by local topography. Thus, based on these pollutant roses, it is likely that ozone concentrations could also be high further to the east and north of the New Mexico Navajo Lake site, further up the San Juan River and Piedra River drainages. While no monitoring exists to confirm or deny, winds could also flow up other drainages in summer afternoons, including the Dolores and Animas Rivers.

For ozone precursor gases, NOx monitoring currently exists at six sites in the Four Corners region (see NO_2 sites map), including two Southern Ute tribe sites and the USFS Shamrock site in Colorado, and three NMED sites. A Navajo Nation site in Shiprock, NM is scheduled to commence operation. Two other sites previously had NOx monitoring. NO_2 levels have been fairly steady over the years at most sites, at a level well below the NAAQS (see NO_2 trends graphs). At two sites in particular, San Juan Substation, NM and Bloomfield, NM, the NO_2 levels do appear to be increasing over time. NO, unfortunately, has not been reported consistently as it is not designated a criteria pollutant. However, NO levels do appear to be increasing at both Southern Ute Tribe sites, Ignacio and Bondad (see NO trends graphs). These increases in NO and NO_2 are of concern due to the potential for increased ozone formation and also indicates that there are increased combustion sources in the area, possibly due to oil and gas development and increased traffic. VOC baseline monitoring for San Juan County, New Mexico was conducted in 2004 and 2005 at three sites. One site was near Bloomfield, NM near some industrial sources, a second near the San Juan power plant and the third site was near Navajo Lake, in an oil and gas development area. Results showed that alkane concentrations dominated, especially ethane and propane. The biogenic compound isoprene and the highly reactive VOC compounds, ethylene and propylene, were not present in significant quantities.[6,7]

Data Gaps:
While it would appear that there is a sufficient ozone monitoring network in the Four Corners region, some areas are lacking. Pollutant roses were developed to determine the directions from which ozone precursors are most likely to be transported by wind (see ozone pollutant roses). In general, for summer afternoon periods when ozone levels are expected to be highest, winds are generally from the west to southwest. Oil and gas development increased significantly after many of the current sites were installed. This development has provided a significant increase in both VOC and NOx precursor gas sources to the region. Ozone monitoring currently exists in the major oil and gas development areas, but little downwind ozone monitoring currently exists.

VOCs are also a gap, as the short-term studies in 2004 and 2005 were located toward the southern edge of the oil and gas development area, or not in the development area at all. While emissions inventories can provide an estimate of total VOCs that may be released to the atmosphere, these are primarily based on predicted emissions, not on actual measurements. This is a concern as different VOCs have different ozone formation potentials and the oil and gas development has dramatically increased in the region since these studies.

Suggestions for Future Monitoring Work:

C. Install and operate two or three long-term continuous monitoring stations for ozone. One station would be located upstream of Navajo Lake, in the San Juan River drainage toward Pagosa Springs, CO, or in the Piedra River drainage, toward Chimney Rock, CO. This area is toward the northeastern portion of the Four Corners region and is downwind of many VOC precursor gas sources from oil and gas development. The second station would be located to the north of Cortez. This area is in the north-central portion of the Four Corners region and is downwind of both an urban area and any precursor gas emissions that would funnel up between Sleeping Ute Mountain and Mesa Verde. If funding exists, a third site in Arizona on Navajo Nation land, in the southwest portion of the Four Corners area, is recommended. This site, possibly at Canyon de Chelly National Monument, would be to the west of a high ozone area as determined in the 2003 passive ozone study and would provide a good representation of regional ozone levels entering the Four Corners area. Each site, including shelter and instrumentation, would cost approximately $15,000 to $20,000 (total = $45,000 to $60,000). Annual operating costs (not including field personnel) would be approximately $1,500 per site (total = $3,000).

D. Perform an ozone saturation study using passive samplers across the entire Four Corners region to determine areas of highest ozone concentration. This would help determine if existing or new continuous monitoring sites are located in appropriate areas or if continuous ozone monitors need to be added or moved. It is expected that at least 20 passive ozone sites over the four-state region would be needed. Running for 30 days during a summer, the approximate cost would be $22,000 (not including field personnel time).

   (Note: In early July 2007, the Colorado legislature appropriated funding for passive ozone monitoring in Colorado. As a result, a short-term study was performed in three areas of Colorado at 50 locations. These areas included the north Front Range, central western and southwestern/Four Corners. For the southwestern area, 12 passive ozone sampling sites were operated from early August to early September 2007. While not a definitive study, funding is expected to be available in future years to perform more refined passive ozone monitoring.)

E. Perform monitoring for VOCs (in particular NMOCs) and carbonyls in the oil and gas development areas to determine the actual constituents in the emissions from wellheads, leaks and tanks. This would help in determining the potential for ozone formation from these compounds. This suggestion also includes follow-up monitoring for VOCs, both in and near the oil and gas development area, to compare to the 2004 and 2005 baseline data from San Juan County, New Mexico. A minimum of four to five sites is recommended; two sites in the oil and gas development area, one background site and one or two follow-up sites. For a year of monitoring, every sixth day, the approximate cost (not including field personnel time) would be $45,000 per site (total = $180,000 to $225,000).

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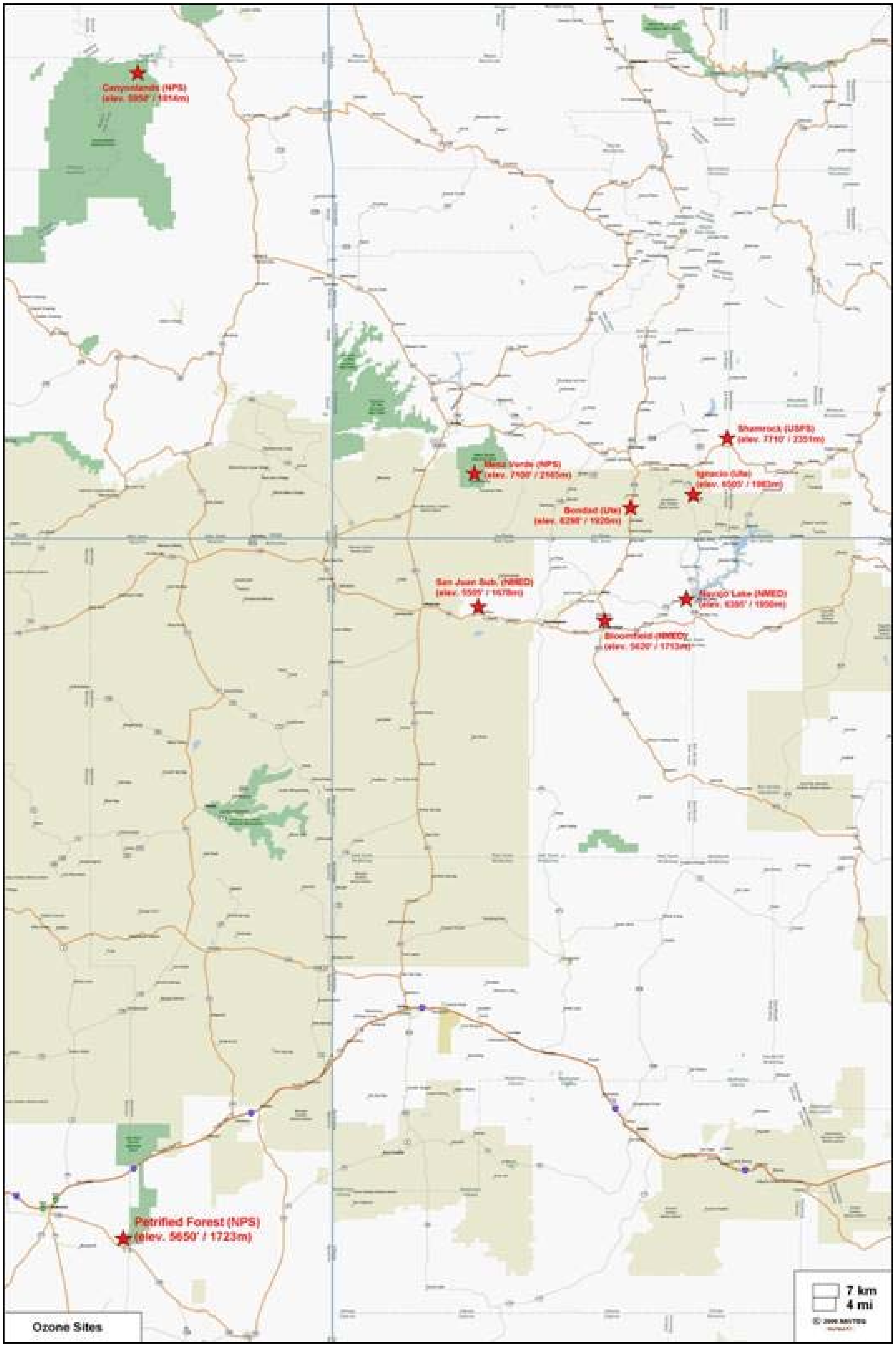
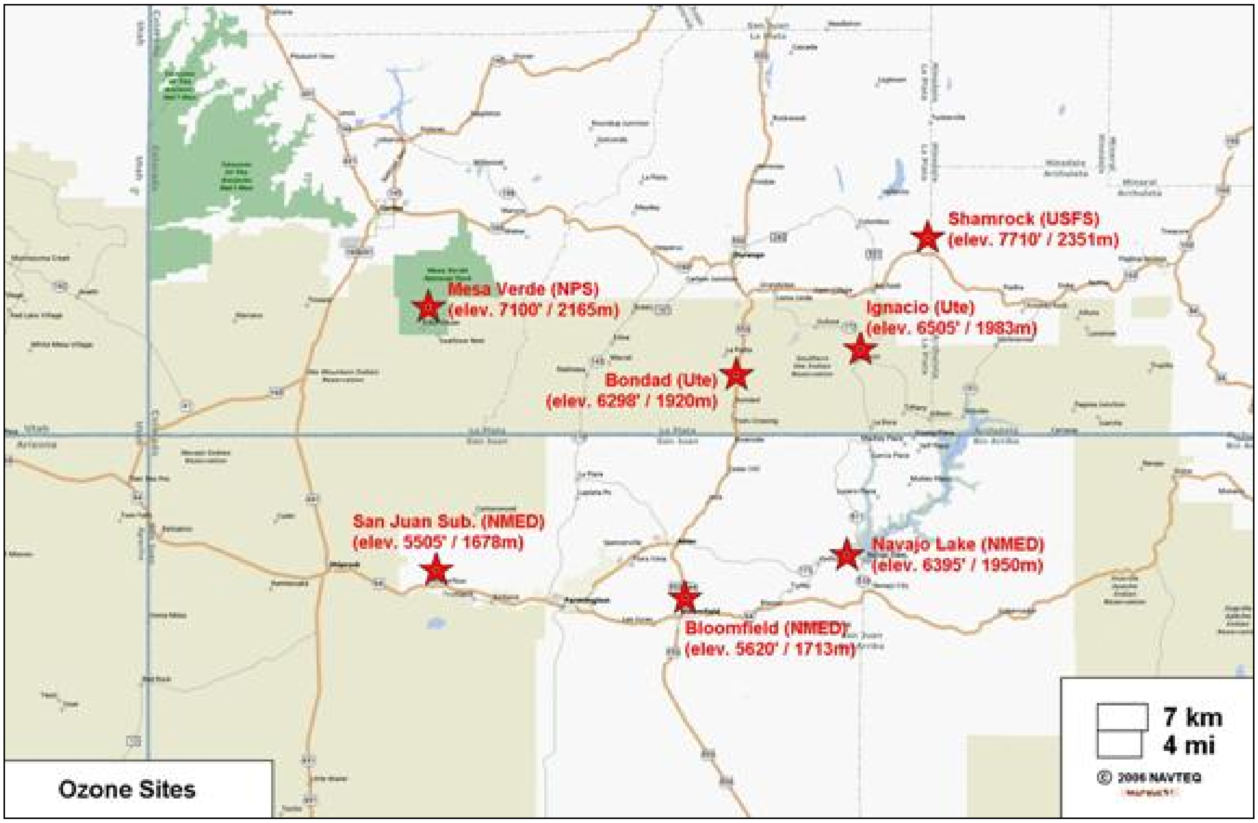
K. Lakes Environmental Software. WRPLOT View. http://www.weblakes.com/lakewrpl.html.

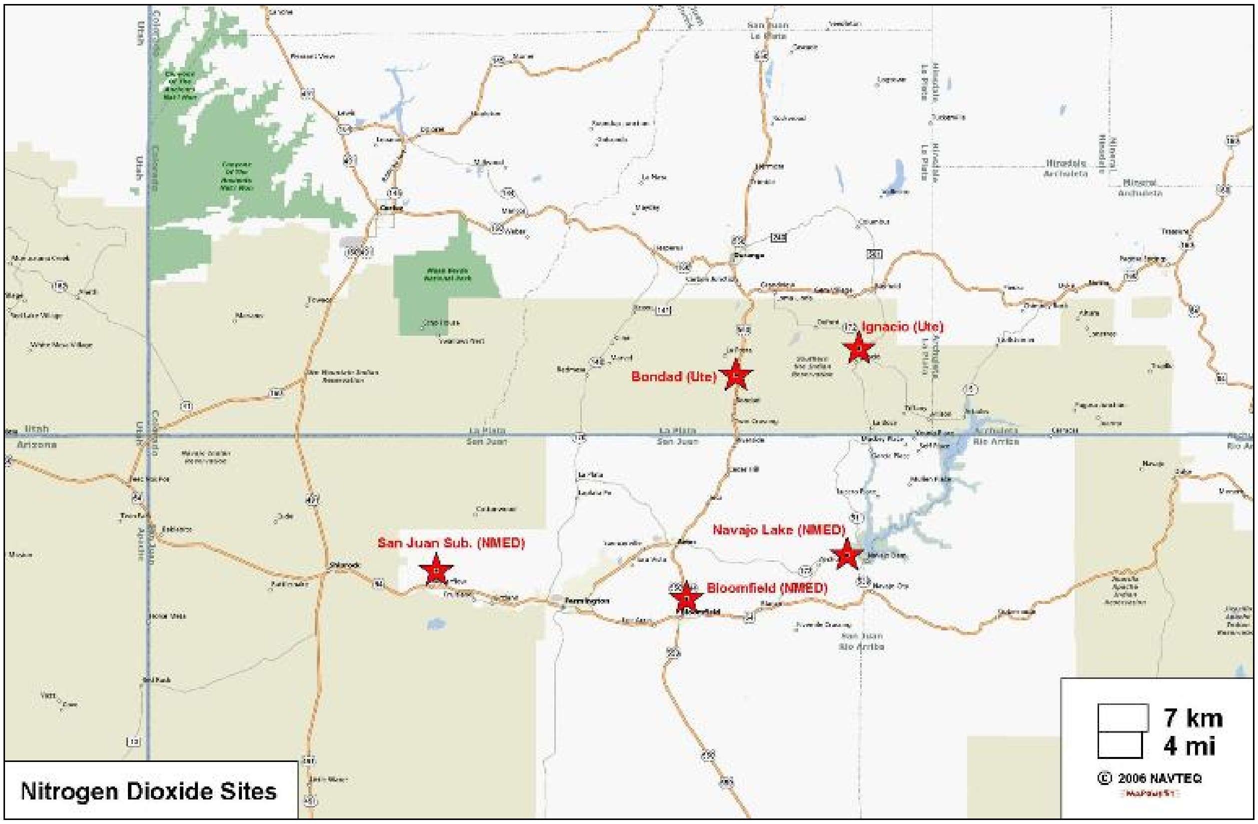
Four Corners --- Continuous Ozone Sites in 2006



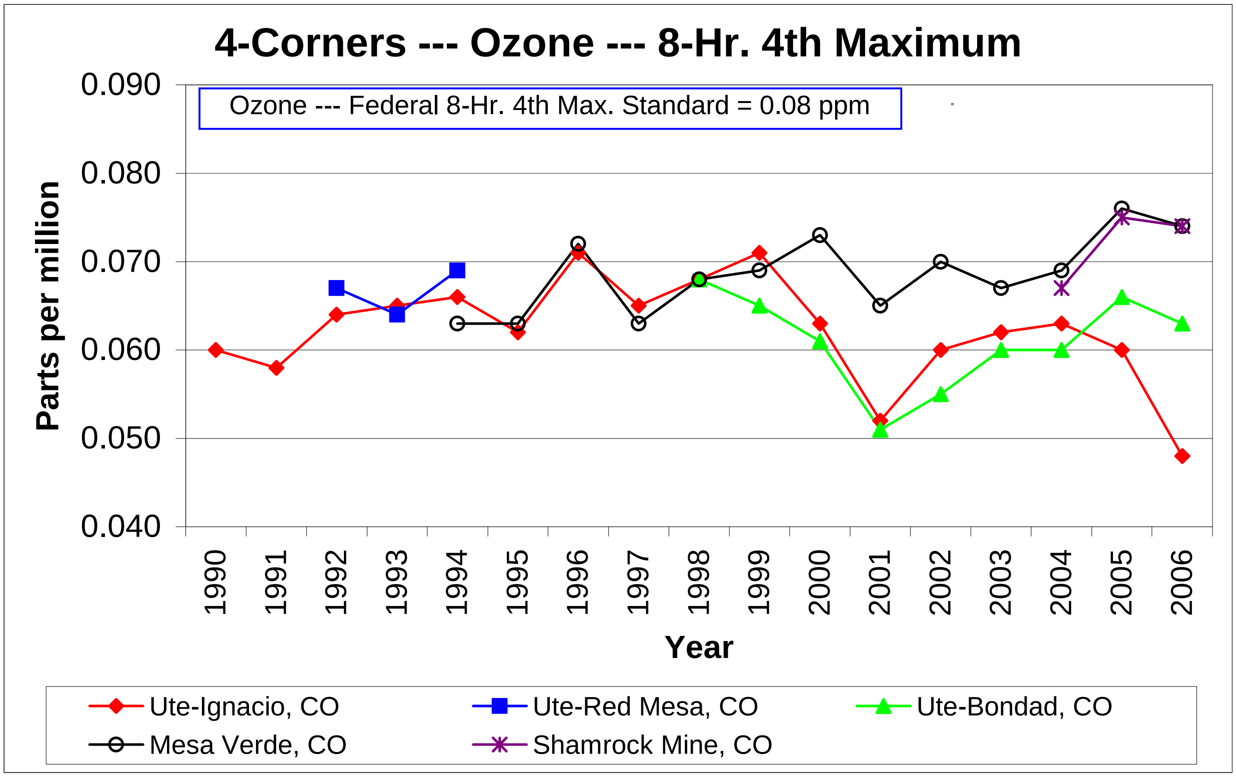
Close-in Four Corners --- Continuous Ozone Sites in 2006

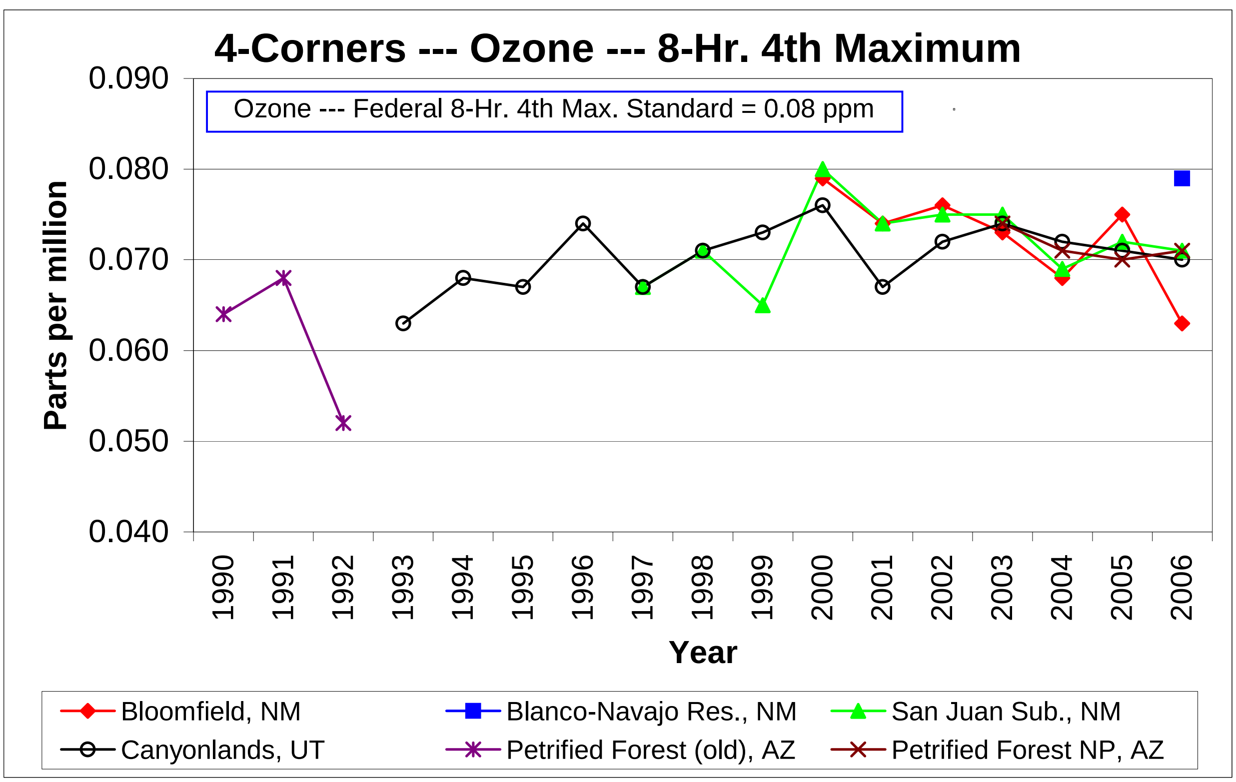


Four Corners --- Continuous Nitrogen Dioxide Sites in 2006

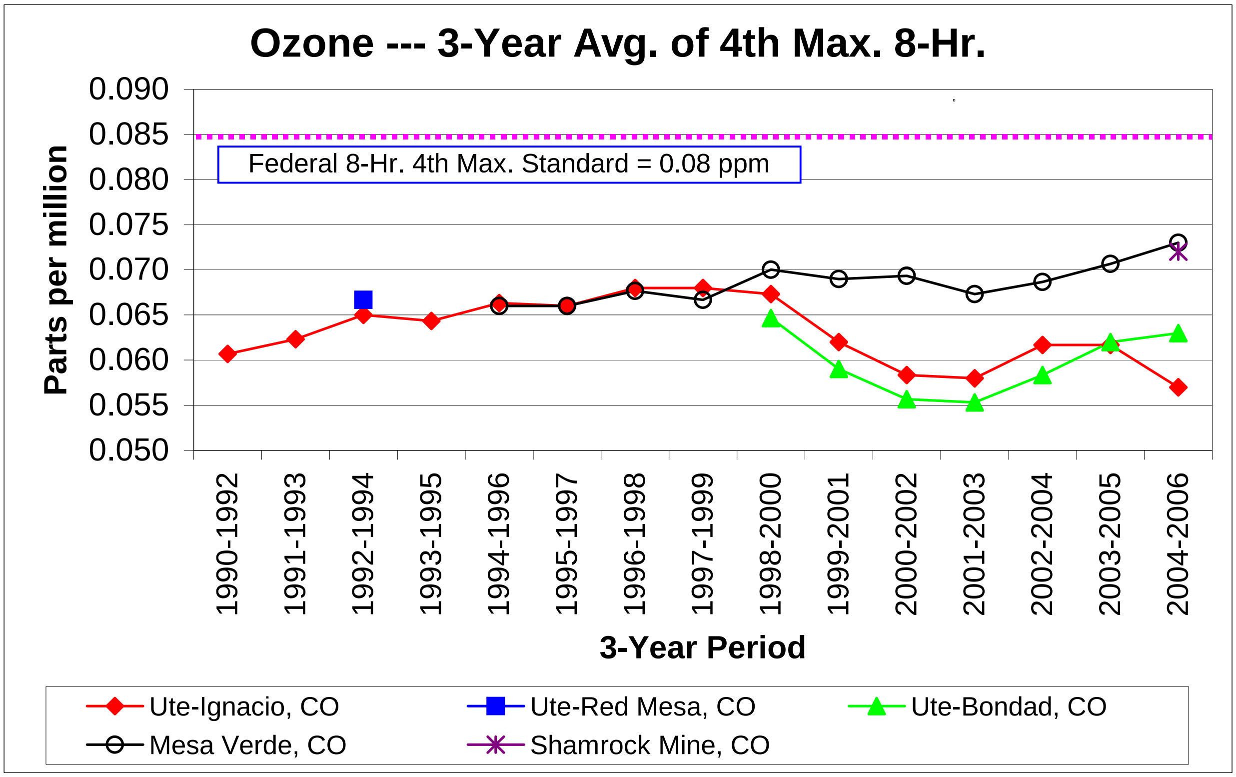


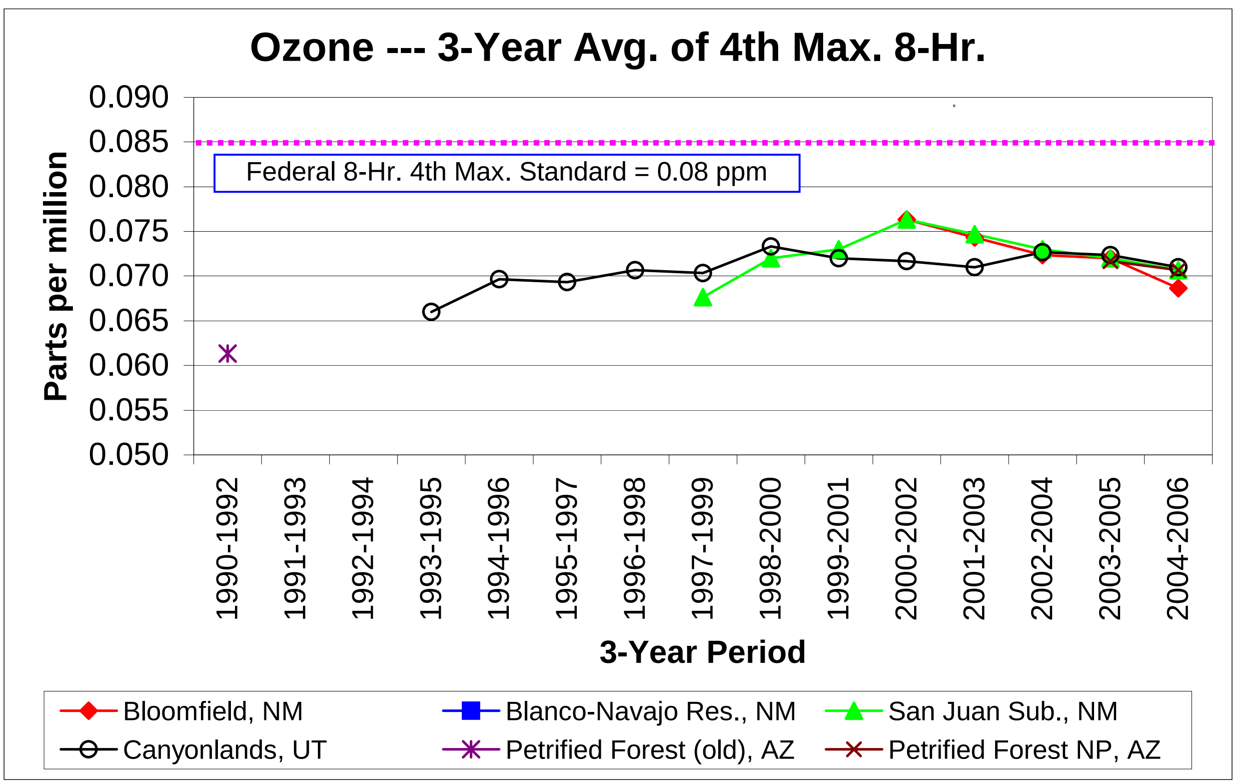
Four Corners --- Ozone Trends (4th Maximum 8-Hour)





Four Corners --- Ozone Standard (3-Year Avg. of 4th Max. 8-Hour)





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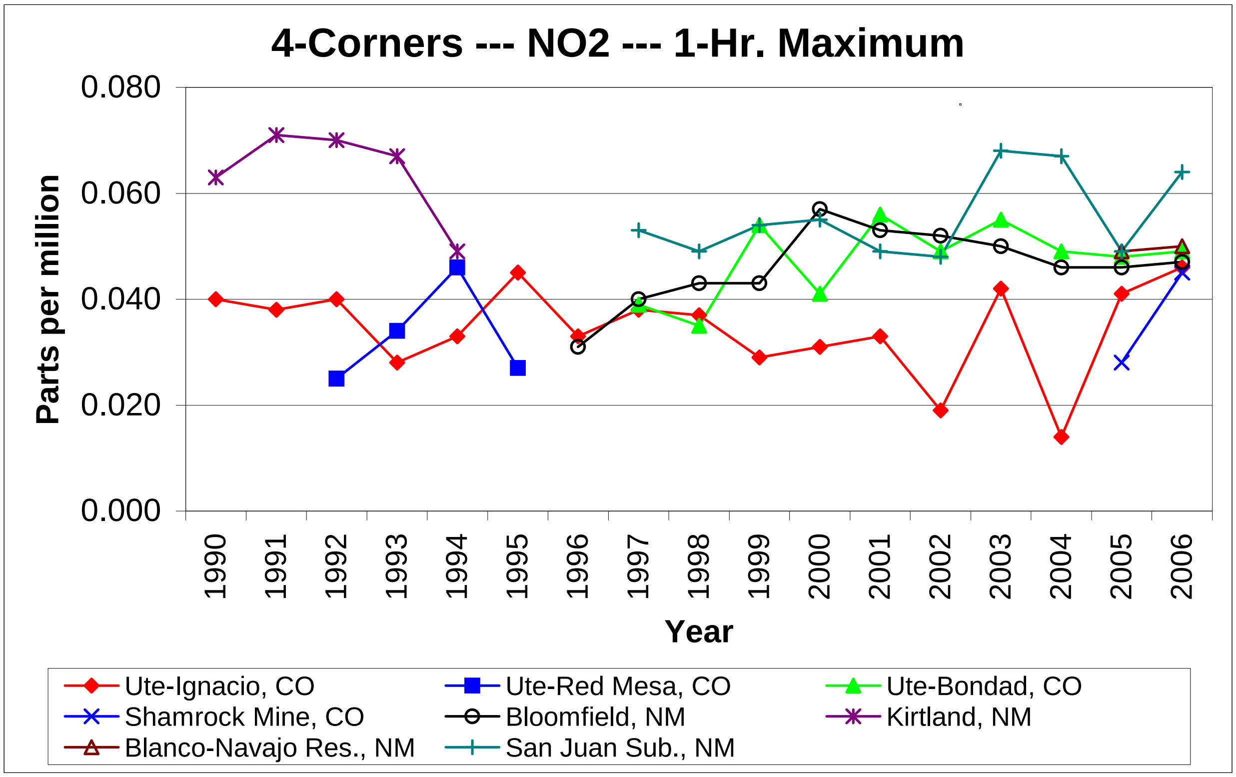
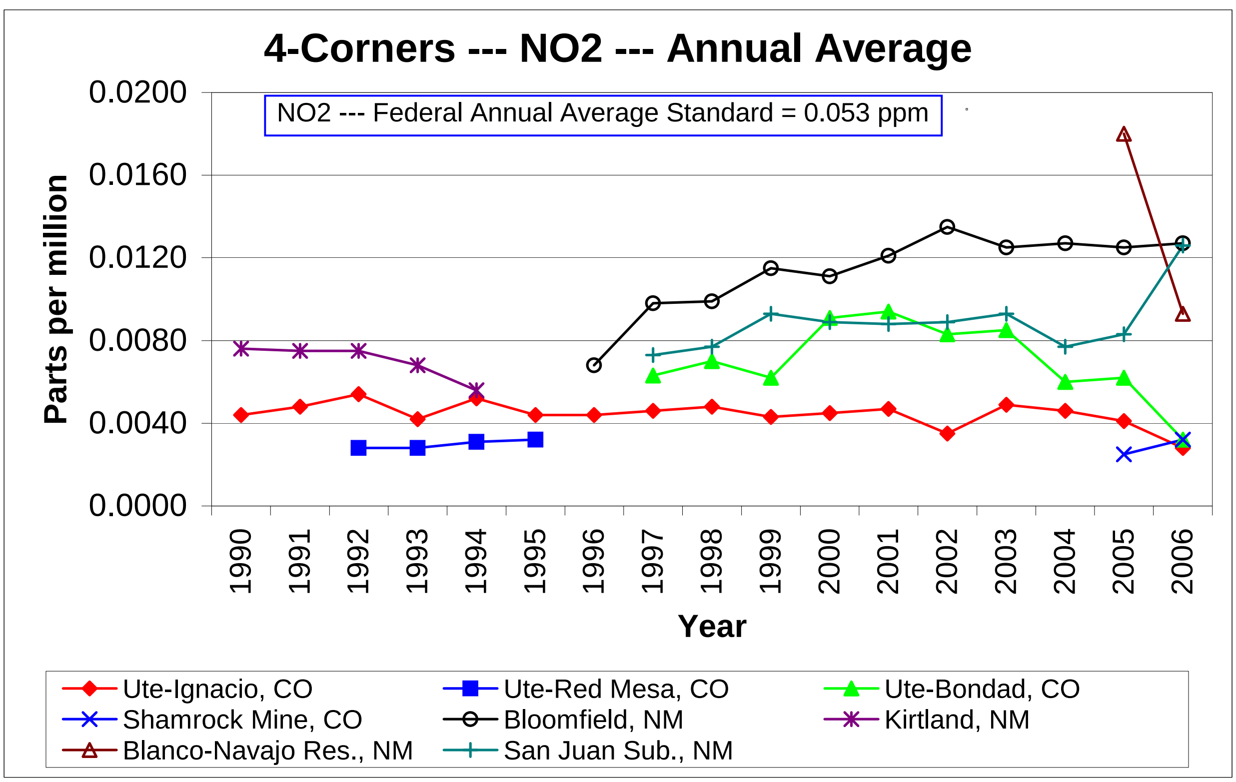
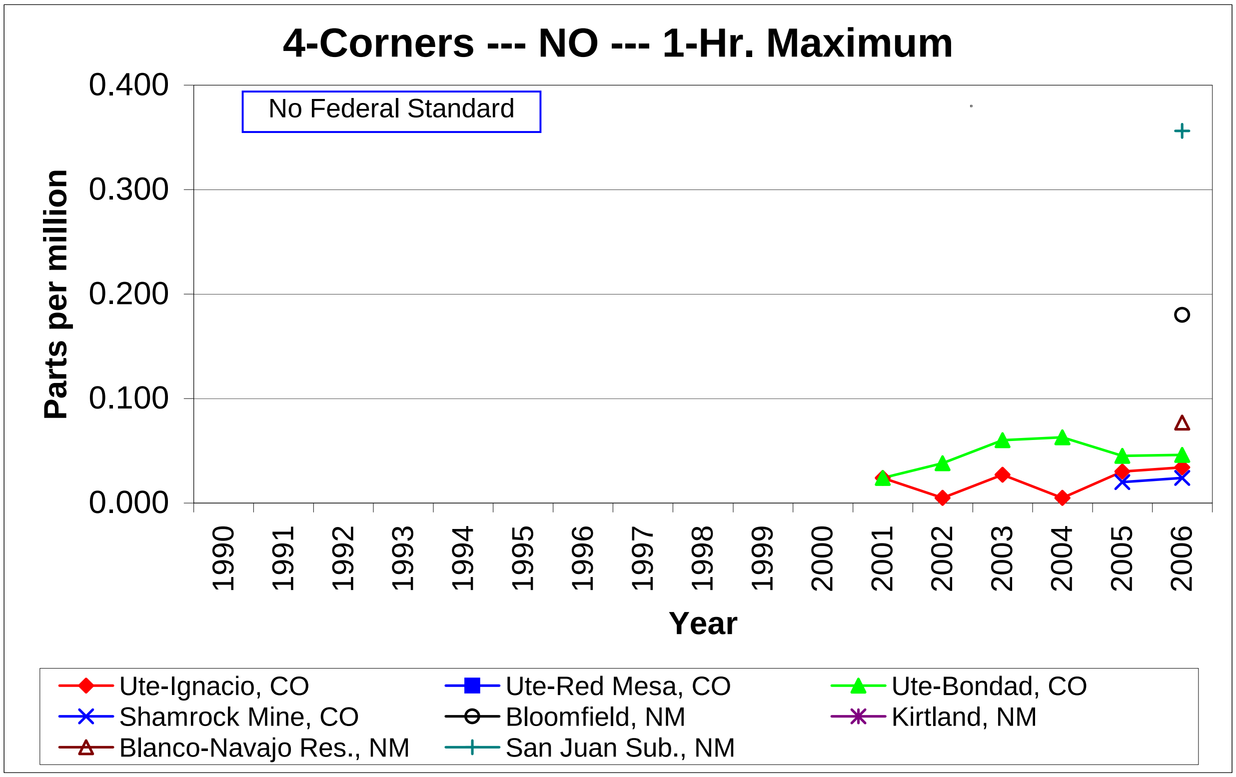
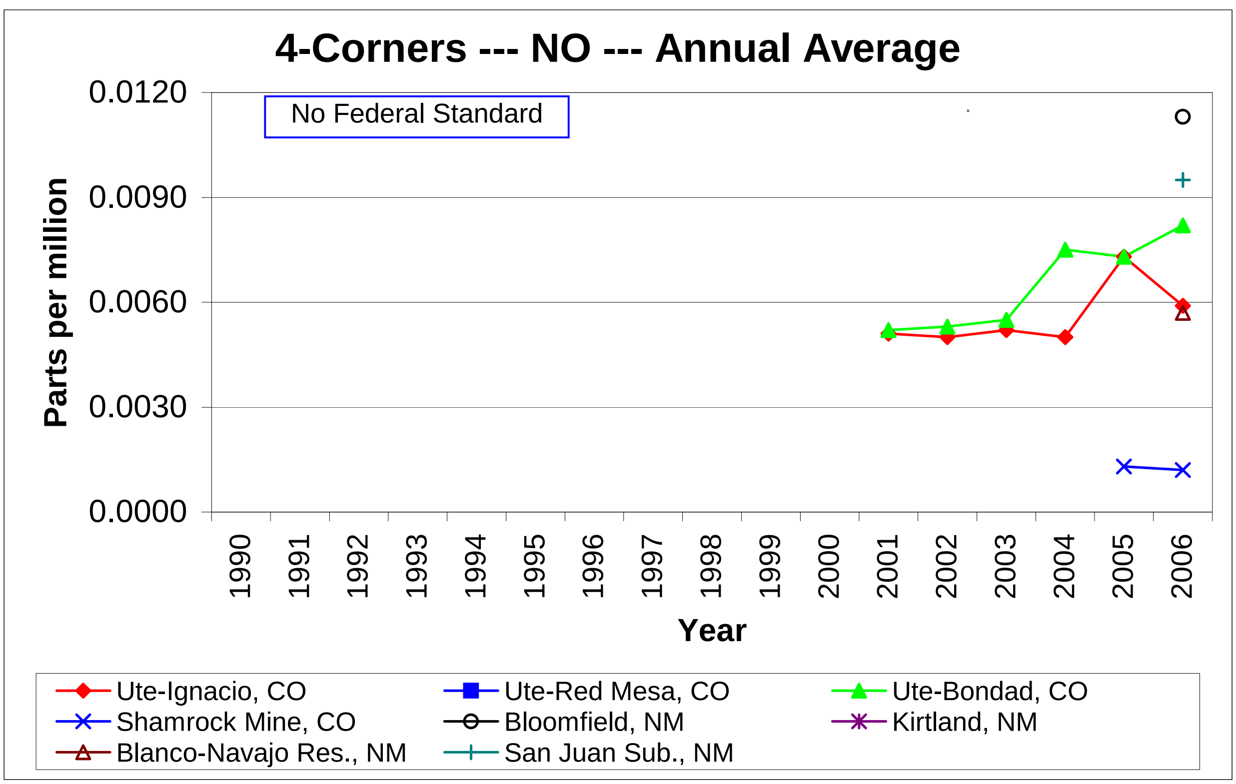


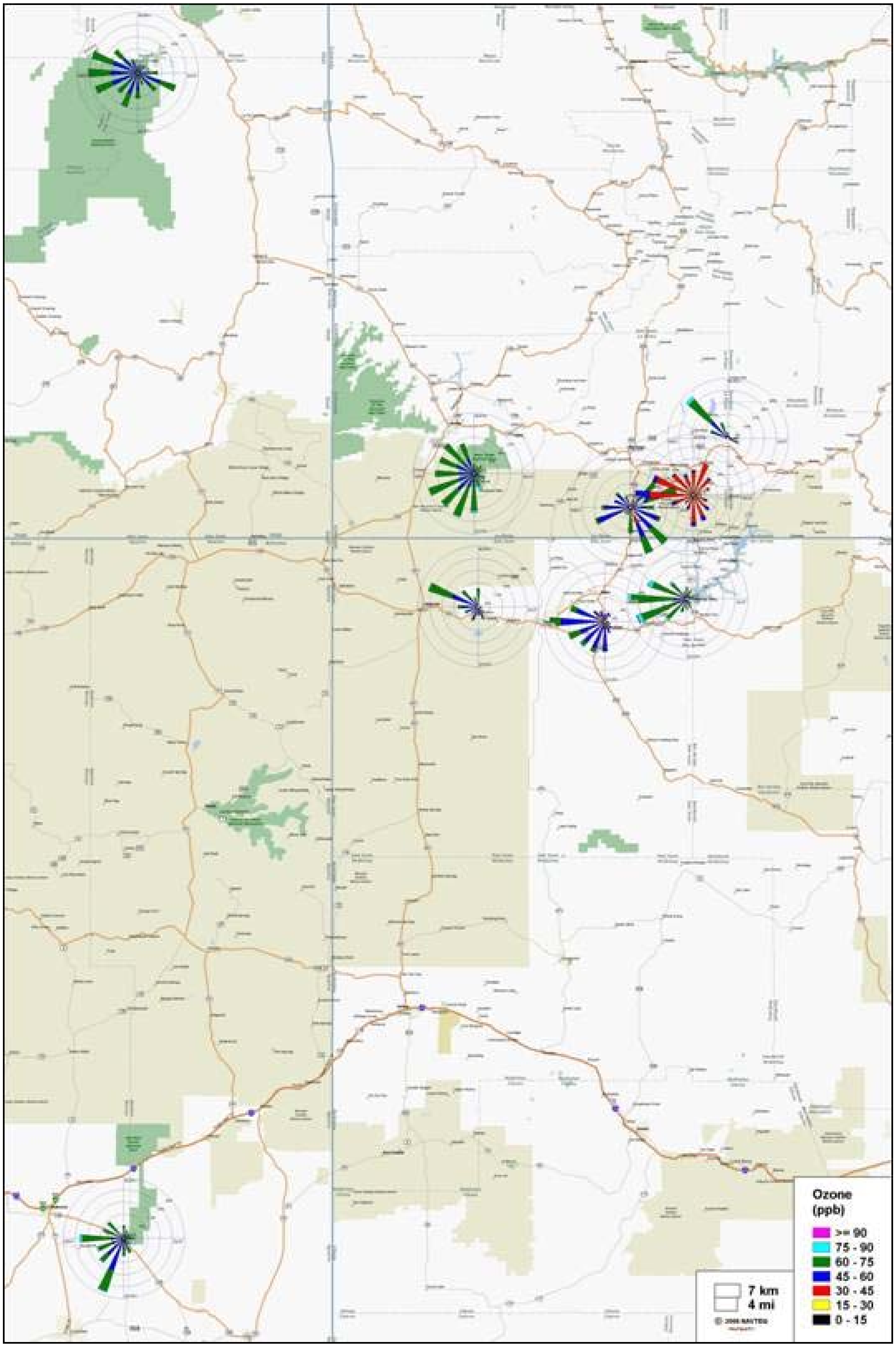


Four Corners --- Nitric Oxide Trends

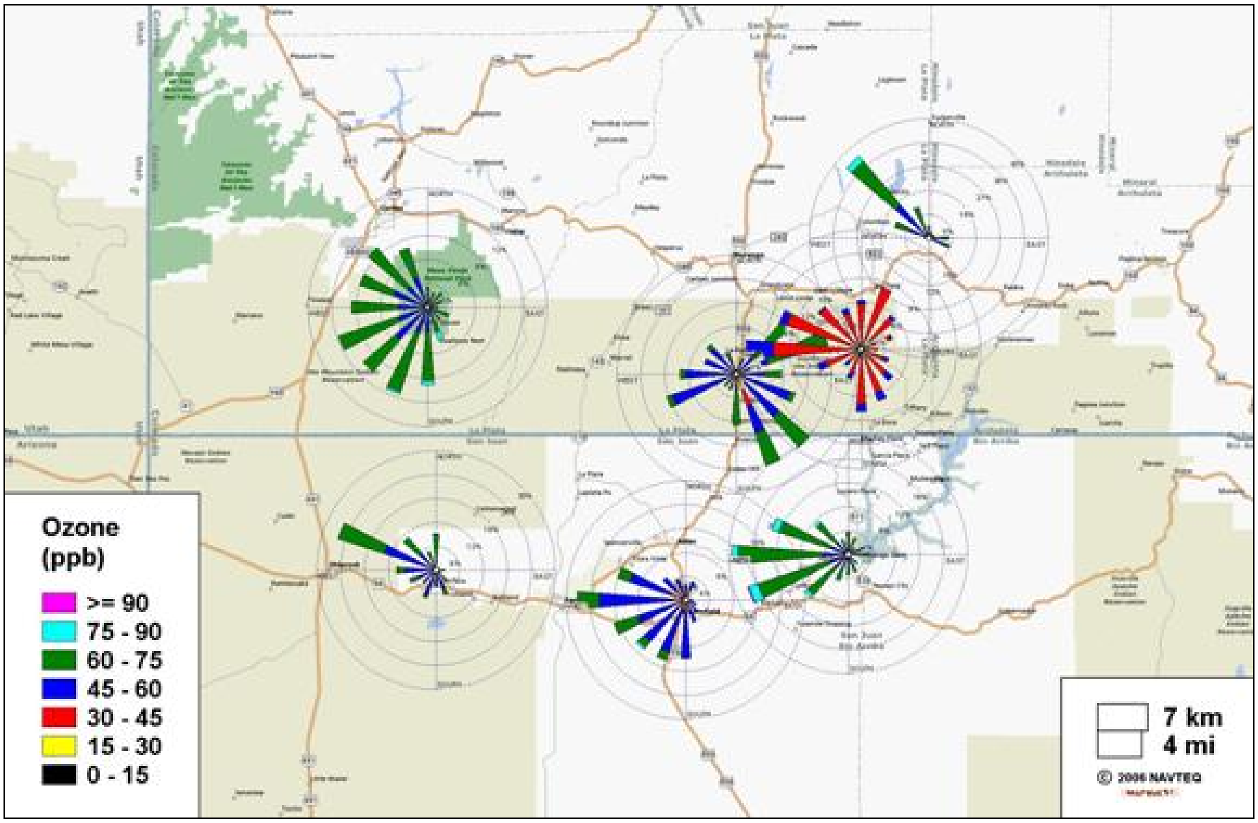




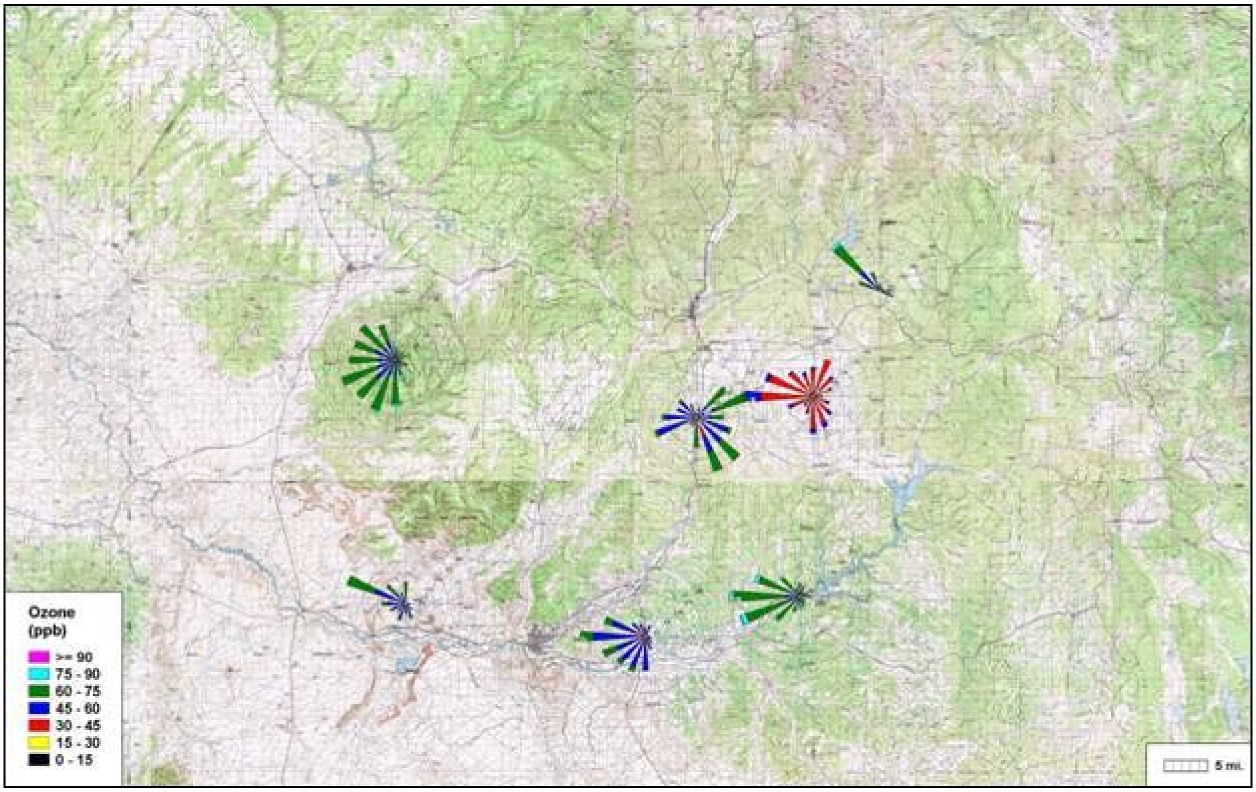
Overall Four Corners --- Summer Afternoon Ozone Pollution Roses (2006)



Close-in Four Corners --- Summer Afternoon Ozone Pollution Roses (2006) (Political boundary map)



Close-in Four Corners --- Summer Afternoon Ozone Pollution Roses (2006)
(Topographic map)



Carbon Monoxide, Particulates and Other Common Pollutants

Background:

Rationale and Benefits**:**
Carbon monoxide, or CO, is a colorless, odorless gas that is formed when carbon in fuel is not burned completely. It is a component of motor vehicle exhaust, which contributes about 56 percent of all CO emissions nationwide. Other non-road engines and vehicles (such as construction equipment and boats) contribute about 22 percent of all CO emissions nationwide. Higher levels of CO generally occur in areas with heavy traffic congestion. In cities, 85 to 95 percent of all CO emissions may come from motor vehicle exhaust. Other sources of CO emissions include industrial processes (such as metals processing and chemical manufacturing), residential wood burning, and natural sources such as forest fires. Woodstoves, gas stoves, cigarette smoke, and unvented gas and kerosene space heaters are sources of CO indoors. The highest levels of CO in the outside air typically occur during the colder months of the year when inversion conditions are more frequent.[1]

Carbon monoxide can cause harmful health effects by reducing oxygen delivery to the body's organs (like the heart and brain) and tissues. This results in cardiovascular and/or central nervous system effects, such as chest pains, vision problems and reduced ability to work or exercise.[1] The health-based National Ambient Air Quality Standard (NAAQS) for carbon monoxide is set at a level of 35 parts per million for a one-hour average and 9 parts per million for an eight-hour average.[2]

Particulates are broken into two categories for NAAQS: PM_{10}, which is particulate matter that is 10-microns in diameter and smaller, and $PM_{2.5}$, which is particulate matter 2.5 microns in diameter and smaller. Thus, $PM_{2.5}$ is a subset of PM_{10}. Particulates are an inhalable mixture of solid particles and liquid droplets found in the air. Some particles, such as dust, dirt, soot, or smoke, are large or dark enough to be seen with the naked eye. Others are so small, they can only be detected using an electron microscope. These particles come in many sizes and shapes and can be made up of hundreds of different chemicals. Some particles, known as *primary particles* are emitted directly from a source, such as construction sites, unpaved roads, fields, smokestacks or fires. Others form in complicated reactions in the atmosphere of chemicals such as sulfur dioxides and nitrogen oxides that are emitted from power plants, industries and automobiles. These particles, known as *secondary particles*, make up most of the fine particle pollution in the country.[3]

Particle pollution, especially fine particles, contains microscopic solids or liquid droplets that are so small that they can get deep into the lungs and cause serious health problems. Numerous scientific studies have linked particle pollution exposure to a variety of problems, including increased respiratory symptoms (such as irritation of the airways, coughing, or difficulty breathing), decreased lung function, aggravated asthma, development of chronic bronchitis, irregular heartbeat, nonfatal heart attacks and premature death in people with heart or lung disease.[3] The health-based NAAQS for PM10 is set at a level of 150 micrograms per cubic meter for a 24-hour average. For PM2.5, the health-based NAAQS are set at levels of 35 micrograms per cubic meter for a 24-hour average and 15 micrograms per cubic meter for an annual average.[2]

Other common pollutants in the ambient air that are not covered in other option papers may include lead, carbon dioxide, organic compounds/hazardous air pollutants (HAPs), pesticides, and others. Of these, only lead has a health-based NAAQS, which is 1.5 micrograms per cubic meter for a calendar quarter average.[2]

Lead is primarily emitted from metals processing or waste incinerator sources. Historically, leaded automobile fuels were the primary source.[4] Lead is typically associated with neurological impairment. Carbon dioxide is emitted from a variety of natural and human-related sources. With implications as a greenhouse gas rather than health concerns, the largest man-made source of carbon dioxide, by far, is fossil fuel combustion.[5] Organic compounds can be both toxic and non-toxic in nature. Toxic air pollutants, also known as hazardous air pollutants, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental effects. These compounds can come from a variety of sources, though primarily from industrial or mobile (i.e. motor vehicle) source. Thus, they are typically associated with urban areas.[6] The U.S. Environmental Protection Agency currently lists 188 HAPs for which it would like to reduce atmospheric releases/emissions. While no ambient standards currently exist for these pollutants, workplace standards do exist for some of them. Pesticides are substances or mixture of substances intended for preventing, destroying, repelling, or mitigating any pest.[7] While all regulated pesticides have been tested for health impacts to humans, exposures can and do occur from improper use.

Existing data for the Four Corners region:
Carbon monoxide in the ambient air is currently monitored on a continuous basis at only one site in the Four Corners region. This is at the Southern Ute Tribe's Ignacio site in southern Colorado. Monitoring was performed at New Mexico's Farmington site, but was discontinued in 2000. (See the CO site locations map.) All of the data are available on EPA's Air Quality System.[8] Ambient carbon monoxide levels in the Four Corners region are well below the level of the current NAAQS (see the CO trends and standards graph). Carbon monoxide levels nationwide are now very low due in large part to improved vehicle technology and emissions controls.

PM_{10} in the ambient air is, historically, the most heavily monitored pollutant in the Four Corners region. (See the PM_{10} site locations map.) Most of the monitoring has been performed using filter-based "high-volume" samplers that collect 24-hour samples and most of the data are available on EPA's Air Quality System.[8] Ambient PM_{10} levels in the Four Corners region are well below the level of the current and former NAAQS (see the PM_{10} trends graphs). As a result, some of the monitors were shut down at the end of 2006.

$PM_{2.5}$ in the ambient air has also been monitored at a number of locations in Four Corners region. (See the $PM_{2.5}$ site locations map.) Most of the monitoring has been performed using filter-based "low-volume" samplers that collect 24-hour samples and most of the data are available on EPA's Air Quality System.[8] Ambient $PM_{2.5}$ levels in the Four Corners region are well below the levels of the current NAAQS for both the 24-hour average and annual averages (see the $PM_{2.5}$ trends graphs). $PM_{2.5}$ has also been monitored as part of the IMPROVE network. These data are not on EPA's Air Quality System but may be obtained on the IMPROVE website.[9]

No monitoring for lead exists in the Four Corners region. Due to the introduction of unleaded gasoline in the 1970's, ambient lead levels have decreased to levels that are near instrument detection levels. Likewise, no monitoring exists for other pollutants such as carbon dioxide, HAPs or pesticides. While carbon dioxide is a greenhouse gas and is emitted from combustion sources, it is not considered to be toxic at typical ambient concentrations. Thus, there has been no specific reason for monitoring and no standards exist. No standards currently exist for organic compounds, including HAPs (such as volatile and semi-volatile organic compounds) and pesticides. Much of the monitoring for these compounds has been performed in urban areas where concentrations are expected to be higher, particularly for the HAPs, and more people are at risk for exposure. Several pilot and trends studies are currently underway across the nation, but the cost is very high for routine monitoring. Volatile organic compound baseline monitoring for San Juan County, New Mexico was conducted in 2004 and 2005 at three sites by the U.S. Environmental Protection Agency (EPA) Region 6. This study was primarily for ozone precursor organic compounds rather than for overall HAPs.[10,11]

Data Gaps:
Due to the very low levels of carbon monoxide, PM_{10} and $PM_{2.5}$ at existing or former air monitoring sites and at other surrounding areas, there is not expected to be any areas of the Four Corners region that need additional monitoring of these threeo pollutants to demonstrate NAAQS compliance. While there has been no monitoring for lead in the Four Corners region, the low levels that are seen nationwide and the lack of sources in the area indicate that no monitoring is likely to be needed. There is no NAAQS for carbon dioxide, so on a health basis, no monitoring is needed.

With organic compounds/HAPs and pesticides, there is little data for the area that exists. However, based on monitoring that is being performed nationwide in EPA's National Air Toxics Trends Study, there are not expected be concentrations that are much different from other areas. Due to the expense of monitoring, other areas would probably suffice as a surrogate. In addition, there are no significant major sources of HAPs in the region to warrant ambient monitoring. As part of "Ozone and Precursor Gases" suggestions, volatile organic compound/non-methane organic compound monitoring is being recommended. Pesticides may be a health issue for the agricultural population. This would lead to specific investigations rather than ambient monitoring sites.

Suggestions for Future Monitoring Work:

No suggestions for additional monitoring of carbon monoxide, PM_{10}, $PM_{2.5}$ and other common pollutants are currently being proposed.

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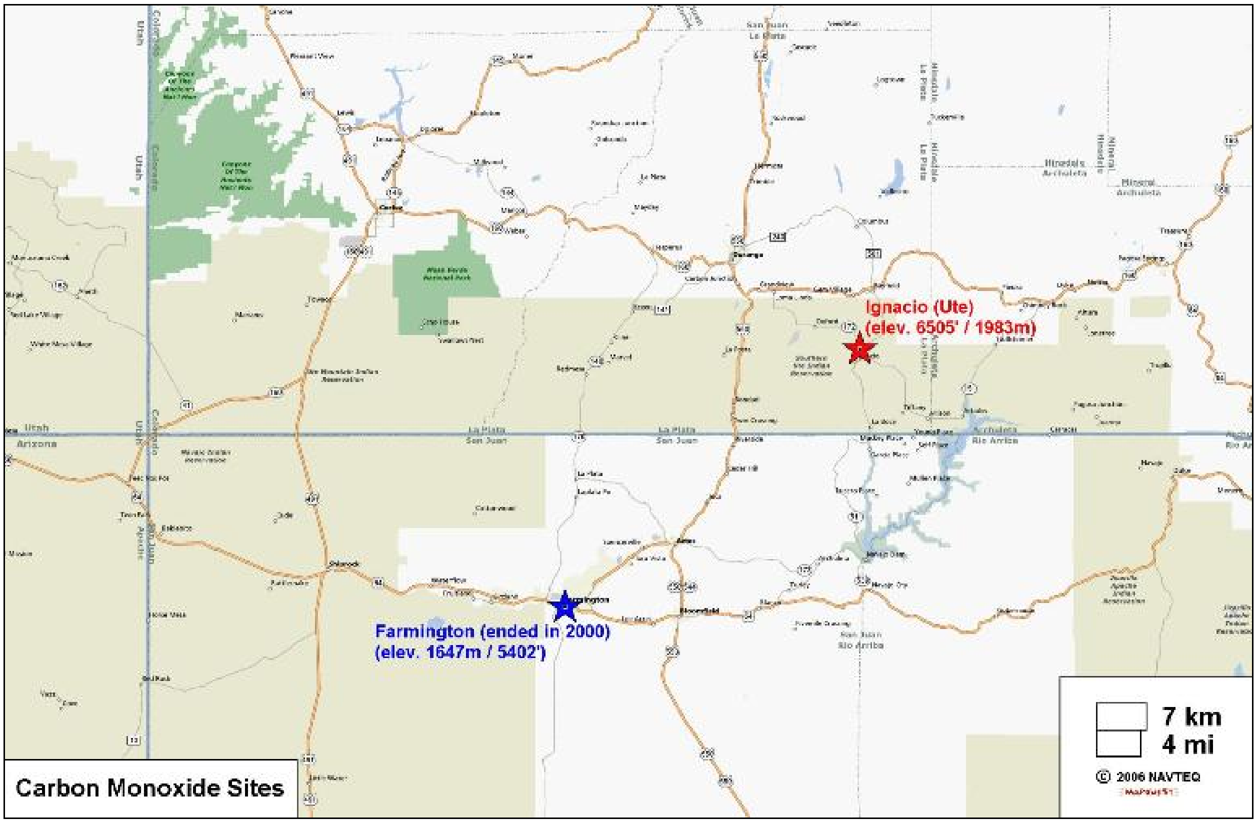
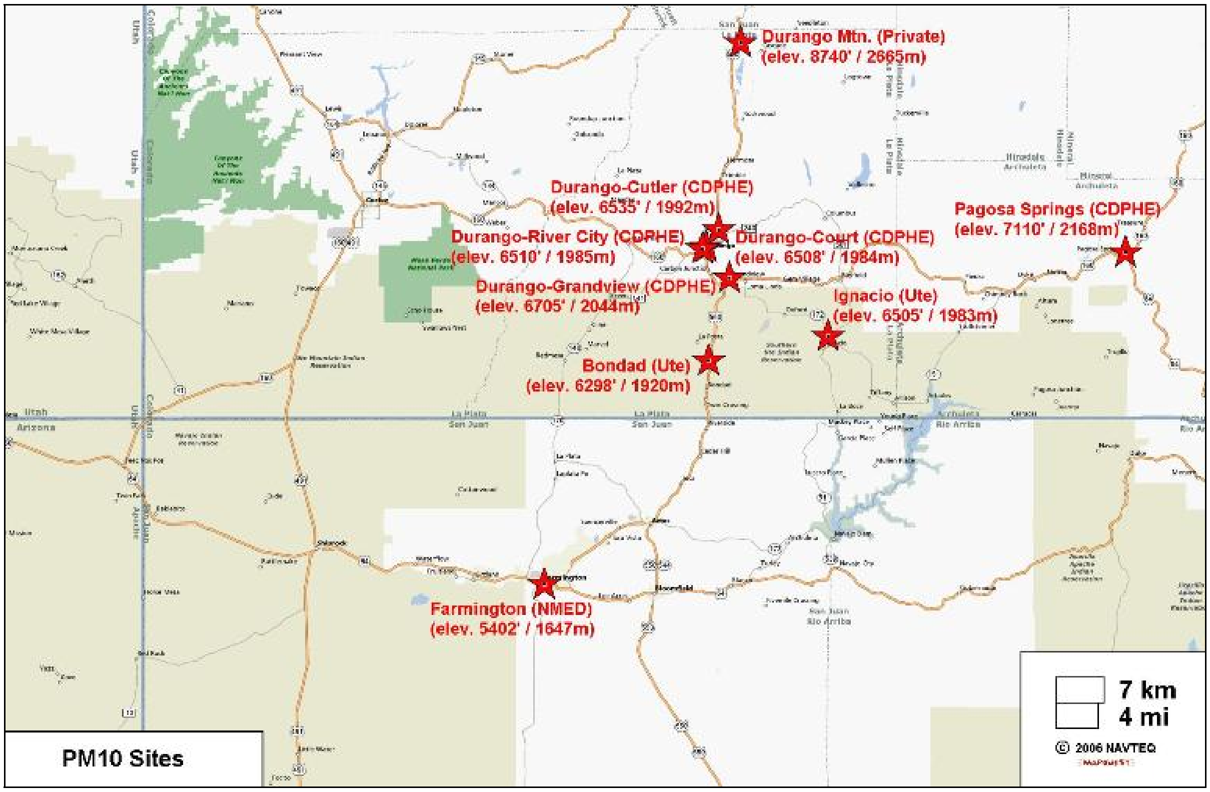
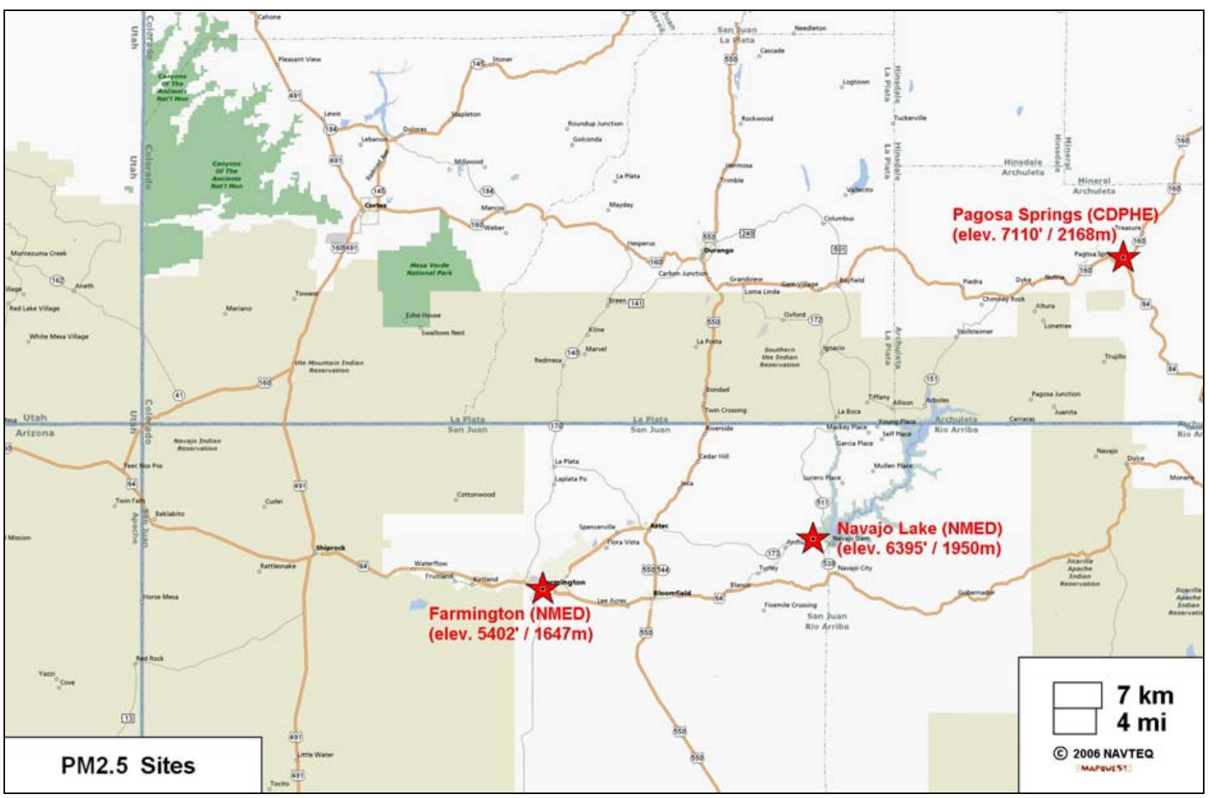
Four Corners --- Continuous Carbon Monoxide Sites in 2006

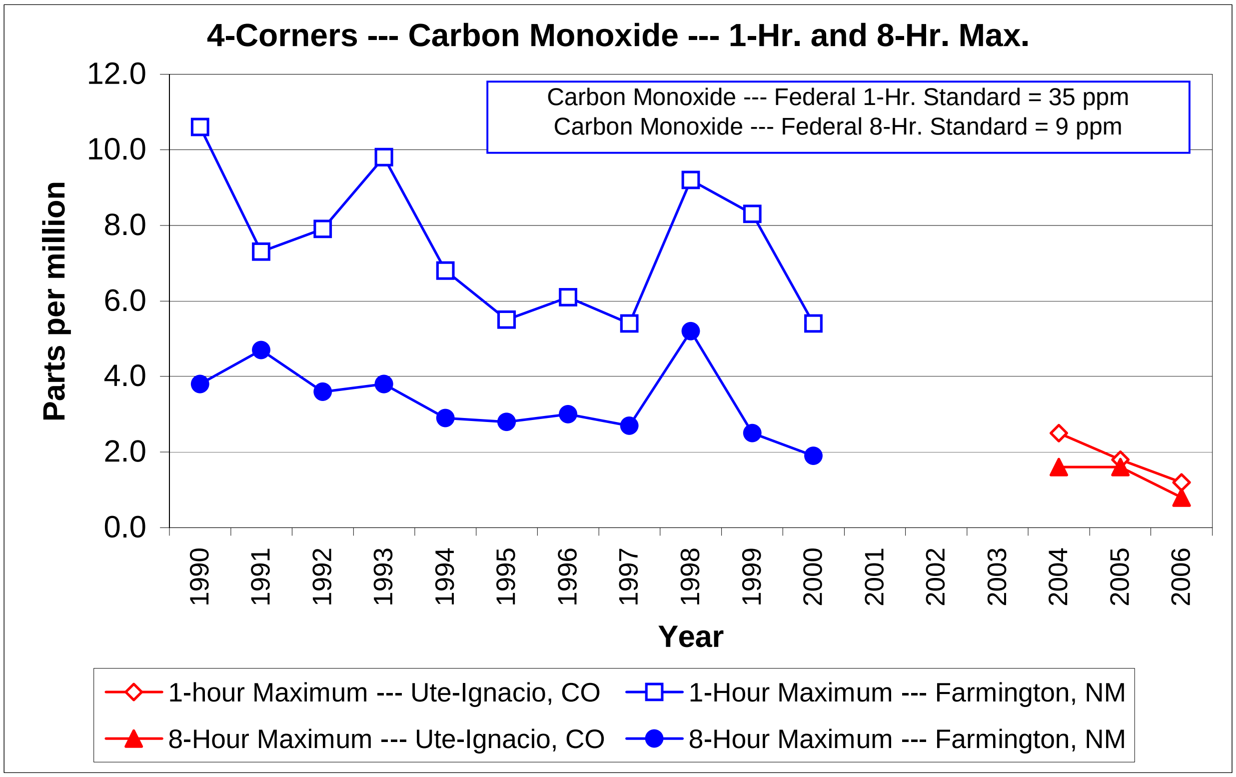


Four Corners --- Particulate Sites in 2006

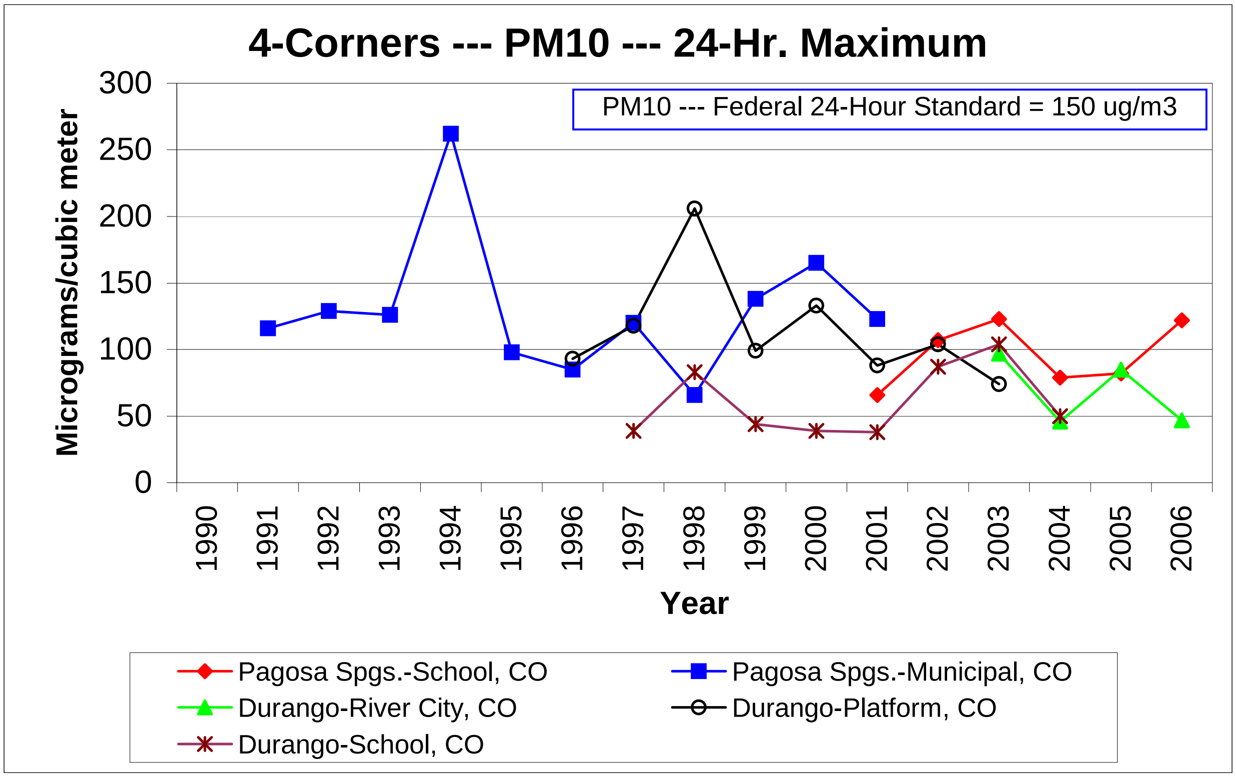


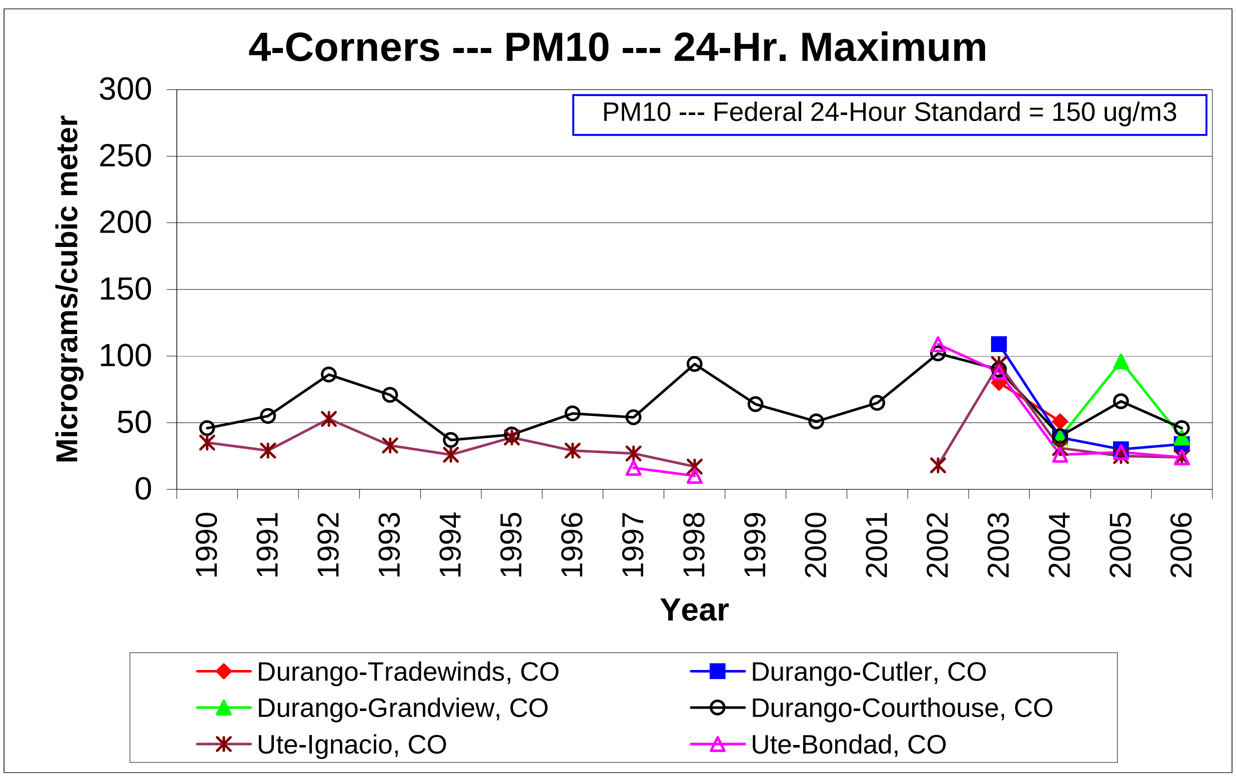


Four Corners --- Carbon Monoxide Trends (1-Hour and 8-Hour)

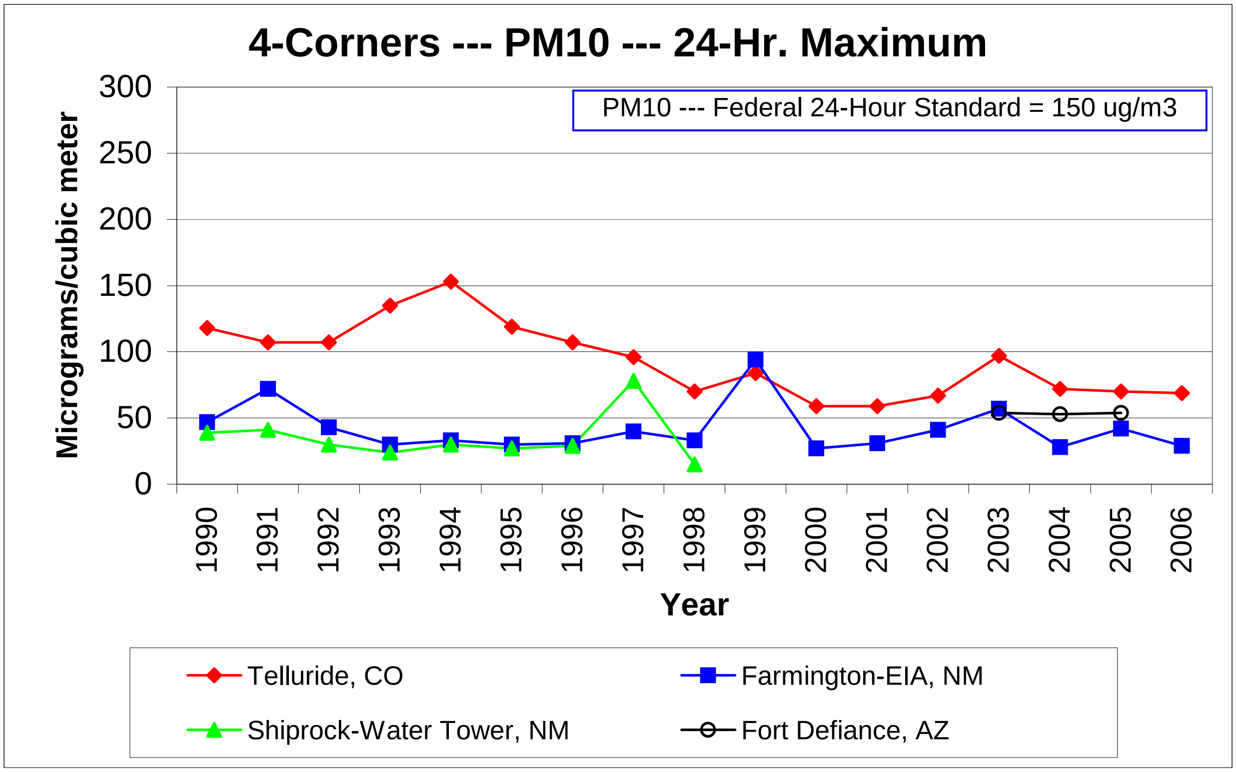


Four Corners --- PM_{10} Trends (24-Hour Maximum)

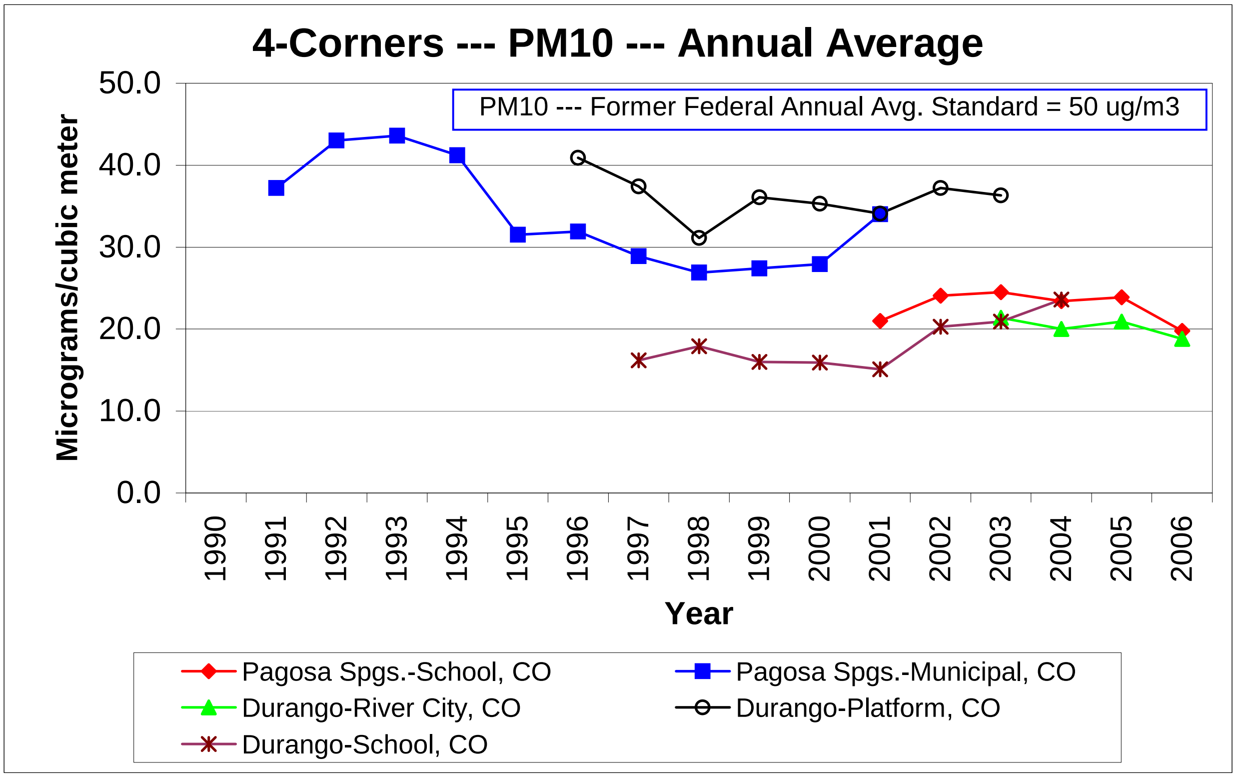


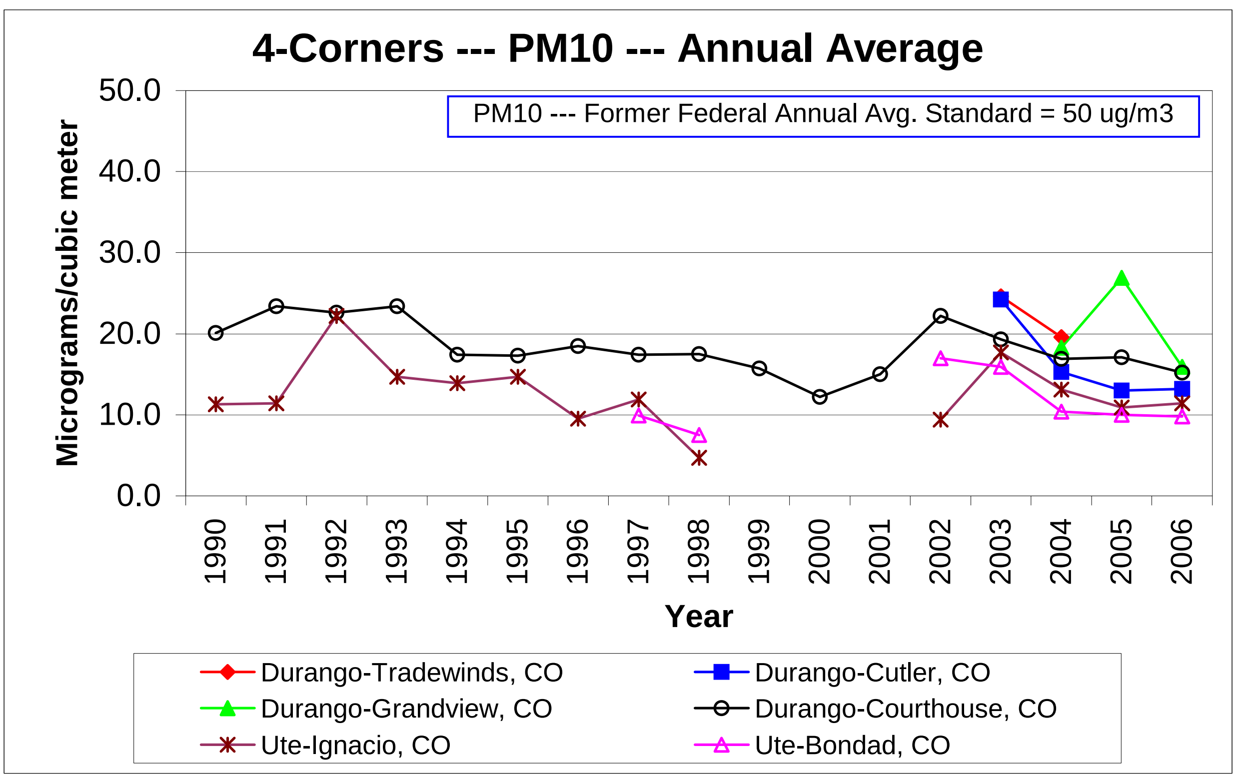


Four Corners --- PM_{10} Trends (24-Hour Maximum) – cont.

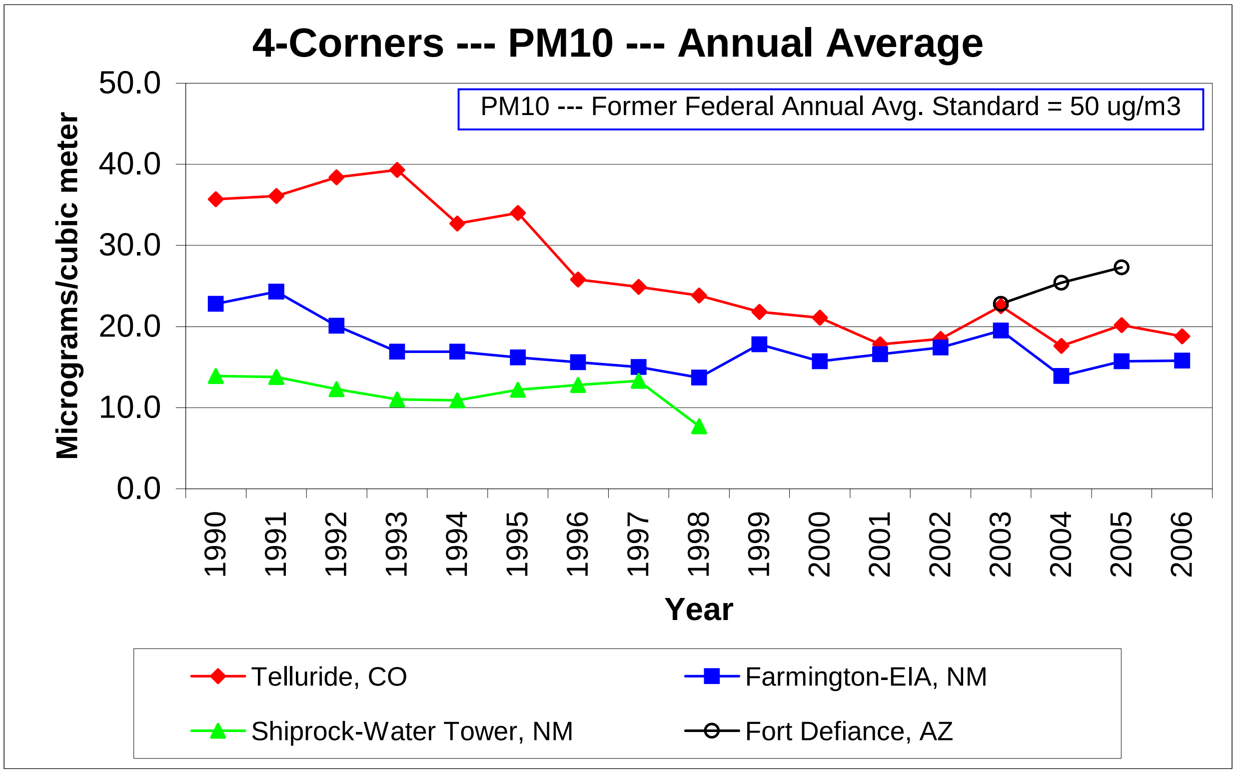


Four Corners --- PM_{10} Trends (Annual average)

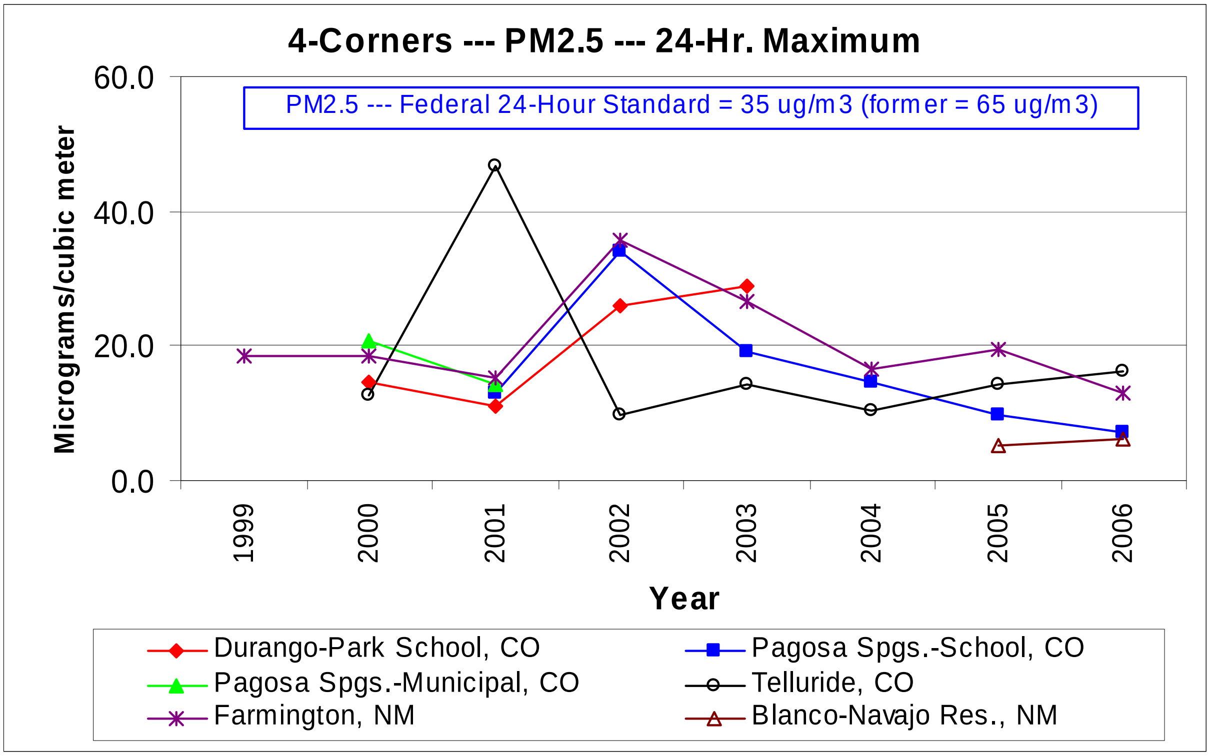




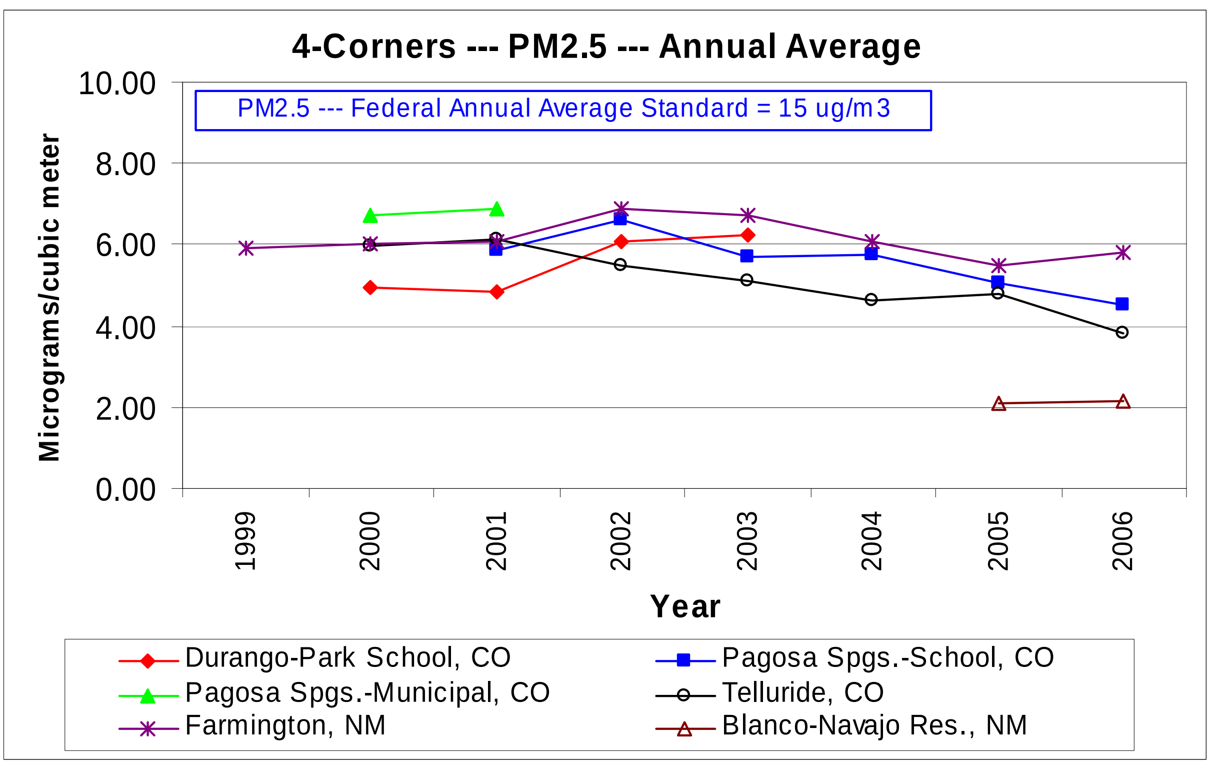
Four Corners --- PM_{10} Trends (Annual average) – cont.



Four Corners --- $PM_{2.5}$ Trends (24-Hour Maximum)



Four Corners --- $PM_{2.5}$ Trends (Annual average)



Uranium, Radionuclides and Radon

Background:

Rationale and Benefits:
Uranium is a naturally-occurring element found at low levels in virtually all rock, soil, and water. In a raw form, it is a silvery white, weakly radioactive metal. It has the highest atomic weight of the naturally occurring elements. Significant concentrations of uranium occur in some substances such as phosphate rock deposits, and minerals such as uraninite in uranium-rich ores. The largest single source of uranium ore in the United States is the Colorado Plateau region, located in Colorado, Utah, New Mexico, and Arizona.[1] Radionuclides are unstable nuclides of elements and may be natural or man-made in origin. Radon is a naturally occurring radioactive gas that is a decay product.

Uranium in soil and rocks is distributed throughout the environment by wind, rain and geologic processes. Rocks weather and break down to form soil, and soil can be washed by water and blown by wind, moving uranium into streams and lakes, and ultimately settling out and reforming as rock. Uranium can also be removed and concentrated by people through mining and refining. These mining and refining processes produce wastes such as mill tailings which may be introduced back into the environment by wind and water if they are not properly controlled. Manufacturing of nuclear fuel, and other human activities also release uranium to the environment.[2]

It is important to keep in mind that uranium is naturally present in the environment (both in air and in water) and is in your normal diet, so there will always be some level of uranium in all parts of your body.[3] The average daily intake of uranium from food ranges from 0.07 to 1.1 micrograms per day. About 99 percent of the uranium ingested in food or water will leave a person's body in the feces, and the remainder will enter the blood. Most of this absorbed uranium will be removed by the kidneys and excreted in the urine within a few days. A small amount of the uranium in the bloodstream will deposit in a person's bones, where it will remain for years.[2]

The greatest health risk from large intakes of uranium is toxic damage to the kidneys, because, in addition to being weakly radioactive, uranium is a toxic metal. Uranium exposure also increases the risk of getting cancer due to its radioactivity. Since uranium tends to concentrate in specific locations in the body, risk of cancer of the bone, liver cancer, and blood diseases (such as leukemia) are increased. Inhaled uranium increases the risk of lung cancer.[2] In addition, uranium can decay into other radioactive substances, such as radium, which can cause cancer if exposed to enough of them for a long enough period of time.[3]

The Occupational Safety and Health Administration has set occupational exposure limits for uranium in breathing air over an 8-hour workday, 40-hour workweek. The limits are 0.05 milligrams per cubic meter (0.05 mg/m^3) for soluble uranium dust and 0.25 mg/m^3 for insoluble uranium dust.[3] Uranium in drinking water is covered under the Safe Water Drinking Act, which establishes maximum contaminant levels, or MCLs, for radionuclides and other contaminants in drinking water. The uranium limit is 30 µg/l (micrograms per liter) in drinking water. The Clean Air Act limits emissions of uranium into the air where the maximum dose to an individual from uranium in the air is 10 millirem.[4] There are no Federal ambient air standards for uranium.

The isotope ^{235}U is useful as a fuel in power plants and weapons. To make fuel, natural uranium is separated into two portions. The fuel portion has more ^{235}U than normal and is called enriched uranium. The leftover portion with less ^{235}U than normal is called depleted uranium, or DU. Natural, depleted, and enriched uranium are chemically identical. Depleted uranium is the least radioactive and enriched uranium the most.[3]

Due to concerns on foreign oil dependence and global warming, renewed interest is being shown in nuclear power generation. The Colorado Plateau, as noted above, has a high concentration of uranium ore. As a result, there is increasing interest in the area for both uranium mining and milling. Of particular concern are milling operations where the mill tailings are rich in the chemicals and radioactive materials that were not removed. In the milling process, the ore is crushed and sent through an extraction processes to concentrate the uranium into uranium-oxygen compounds called yellowcake. The remainder of the crushed rock, in a processing fluid slurry, is placed in a tailings pile.[5] The most important radioactive component of uranium mill tailings is radium, which decays to produce radon.

The radium in these tailings will not decay entirely for thousands of years. Other potentially hazardous substances in the tailings are selenium, molybdenum, uranium, and thorium.[4]

In the Four Corners area, there is currently one operating uranium mill, located near Blanding Utah. A mill has also been proposed near Naturita in western Colorado. Mining operations have also been proposed in San Miguel County in Colorado. This has led to concerns over potentially increased exposures to radionuclides, radon and contaminated dusts from both mills/tailings piles and mines. Immediate concerns would be to the general public in the immediate vicinity of these facilities/operations. However, there are also concerns over longer range air transport of radionuclides, radon and contaminated dusts for the region, especially as the number of these facilities/operations may increase significantly.

Existing uranium data for the Four Corners region:
Currently, little current ambient air monitoring data exists for uranium in the Four Corners region. Neither the States of Colorado nor Utah are currently performing any monitoring around uranium mining or milling operations. From historical mining and milling, total suspended particulate and radionuclide data exist from private monitoring.

As part of National Emissions Standards for Hazardous Air Pollutant regulations (through the U.S. Environmental Protection Agency), monitoring is required to be performed to assess and limit emissions of radon and radionuclides from mines, mills and tailings.[6] U.S. Nuclear Regulatory Commission guidelines call for both onsite and offsite particulate monitoring for radionuclides, radon monitoring and meteorological monitoring at uranium mills. This monitoring is required both prior to operation and during operation.

Data Gaps:
While little ambient air monitoring data exists for uranium mine and milling operations/facilities, emissions monitoring and modeling is required under National Emissions Standards for Hazardous Air Pollutant regulations. Ambient air monitoring is required under Nuclear Regulatory Commission guidelines. Based on this, it is expected that uranium, radionuclide and radon emissions from these facilities/operations is low and should pose no threat to the general public either locally or at a distance. However, as additional facilities become operational, the overall uranium, radionuclide and radon emissions in the Four Corners area will increase and may be significant.

Recommendations:

No recommendations for additional ambient air monitoring of uranium, radionuclides or radon are currently being proposed. However, as uranium mining and milling activities in the Four Corners region increase, this topic may need to be revisited.

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Mercury

Background:

Rationale and Benefits: Methyl mercury is a known neurotoxin affecting humans and wildlife. Coal-fired power plants are the number one source of mercury emissions in the United States[1]. The Four Corners already is home to several power plants that are large emitters of mercury and additional coal-powered plants are proposed for the region. Individuals and community groups in the Four Corners region have expressed great concern about mercury emissions in our region and the existing mercury fish consumption advisories in several reservoirs. Studies of mercury in air deposition, the environment and in sensitive human populations (such as pregnant women) are necessary to set a baseline for current levels and to detect future impacts of increased mercury emissions on these sensitive human populations and natural resources, including the Weminuche Wilderness and Mesa Verde National Park, which are both Federal Class I Areas.

Existing mercury data for the Four Corners region: Total mercury in wet deposition has been monitored at Mesa Verde National Park since 2002 as part of the Mercury Deposition Network (MDN)(Figure 1)[2]. Results show mercury concentrations among the highest in the nation during certain years. Precipitation is relatively low, however, so mercury in wet deposition is moderate (Figure 3)[2]. Mercury concentrations have been measured in snowpack at a few sites in the San Juan Mountains by the USGS and moderate concentrations similar to the Colorado Front Range have been recorded[3]. Mercury concentrations in sport fish from several reservoirs have exceeded the 0.5 microg/g action level resulting in mercury fish consumption advisories for water bodies including McPhee, Narraguinnep, Todden, Navajo, Sanchez and Vallecito Reservoirs and segments of the San Juan River (Figure 4)[4]. Sediment core analysis for Narraguinnep Reservoir show that mercury fluxes increased by approximately a factor of two after about 1970[5]. Finally, atmospheric deposition just to the surface of McPhee and Narraguinnep Reservoirs (i.e., not including air deposition to the rest of the watershed) is estimated to contribute 8.2% and 47.1% of total mercury load to these water bodies, respectively[6].

Data Gaps: Very little data exists for the Four Corners Region with which to assess current risks and trends over time for mercury in air deposition, ecosystems, and sensitive human populations. No data exists for mercury in deposition at high elevations. Wet deposition of mercury at Mesa Verde National Park may not portray the situation in the mountains where mercury may be deposited at higher concentrations and total amounts because of greater rates of precipitation and the process of cold condensation, which causes volatile compounds to migrate towards colder areas at high elevation and latitude[7]. No information about total mercury deposition from the atmosphere (i.e., including dry deposition) exists for low or high elevations in the Four Corners Region. Furthermore, analysis of sources of air deposition of mercury is lacking. Except for a handful of reservoirs, no information exists for incorporation of mercury into aquatic ecosystems and subsequent effects on food-webs. No systematic effort exists to document mercury impacts in a wide range of water bodies over space and time. Lastly, impacts of mercury exposure to human populations are unknown.

Three new studies have begun or will begin in 2007, however. The Mountain Studies Institute (MSI) will measure total mercury in bulk atmospheric deposition (collector near NADP station at Molas Pass, 10, 659 ft. elevation), in lake zooplankton (invertebrates eaten by fish), and in lake sediment cores in the San Juan Mountains, a project funded by the U.S. EPA and USFS[8]. Dr. Richard Grossman is measuring mercury levels in hair collected from pregnant women in the Durango vicinity. Lastly, the Pine River Watershed Group (via the San Juan RC&D) recently was granted start-up funds from La Plata County to initiate event-based sampling of mercury in atmospheric deposition at Vallecito Reservoir and accompanying back-trajectory analyses to locate the source of these storm events.

Suggestions for Future Monitoring Work:

1. Install and operate a long-term monitoring station for mercury in wet deposition for a location at high elevation where precipitation amounts are greater than the site at Mesa Verde NP. Co-location of the collector with the NADP site at Molas Pass would provide data pertinent to Weminuche Wilderness and the headwaters of Vallecito Reservoir. This monitor would be part of the Mercury Deposition Network (MDN). Upgrading the

NADP monitoring equipment at Molas Pass to include the MDN specifications would cost $5,000 to $6,000, while annual monitoring costs are $12,112 plus personnel as of September 2006.

2. Install and operate a long-term monitoring station for mercury in total deposition (wet and dry) for at least one MDN station in the Four Corners Region. Speciated data will be collected and analyzed as is feasible. The MDN is currently developing this program and costs are anticipated at about $50,000 per year.

3. Support multi-year comprehensive mercury source apportionment study to investigate the impact of local and regional coal combustion sources on atmospheric mercury deposition. This type of study would require additional deposition monitoring (i.e., suggestions 1 & 2 above). Speciated data will be collected and analyzed as is feasible. A mercury monitoring and source apportionment study was recently completed for eastern Ohio. (http://pubs.acs.org/cgi-bin/asap.cgi/esthag/asap/html/es060377q.html9). Costs TBD.

Support a study of mercury incorporation and cycling in aquatic ecosystem food-webs, including total and methyl mercury in the food-webs of lakes and wetlands. This option includes studies that determine which ecosystems currently have high levels of total and methyl mercury in food-web components, how mercury levels in ecosystems change over time, where the mercury is coming from, and what conditions are causing the mercury to become methylated (the toxic form of mercury that bio-accumulates in food-webs). This information would allow tracking of mercury risks over time and space and serves as the basis for predicting future impacts. Existing reservoir studies and the upcoming MSI investigation serve as a starting point to build a collaborative and systematic approach. Costs TBD.

Support continued studies of mercury concentrations in sensitive human populations in the region to understand what exposure factors increase likelihood of unhealthy mercury levels in the body. Dr. Richard Grossman's study serves as a starting point to continue this effort. Costs TBD.

Form a multi-partner Mercury Advisory Committee that would work collaboratively to prioritize research and monitoring needs, develop funding mechanisms to sustain long-term mercury studies, and work to communicate study findings to decision-makers. The Committee would include technical experts and stakeholder representatives from States, local governments, land management agencies, watershed groups, the energy industry, etc.

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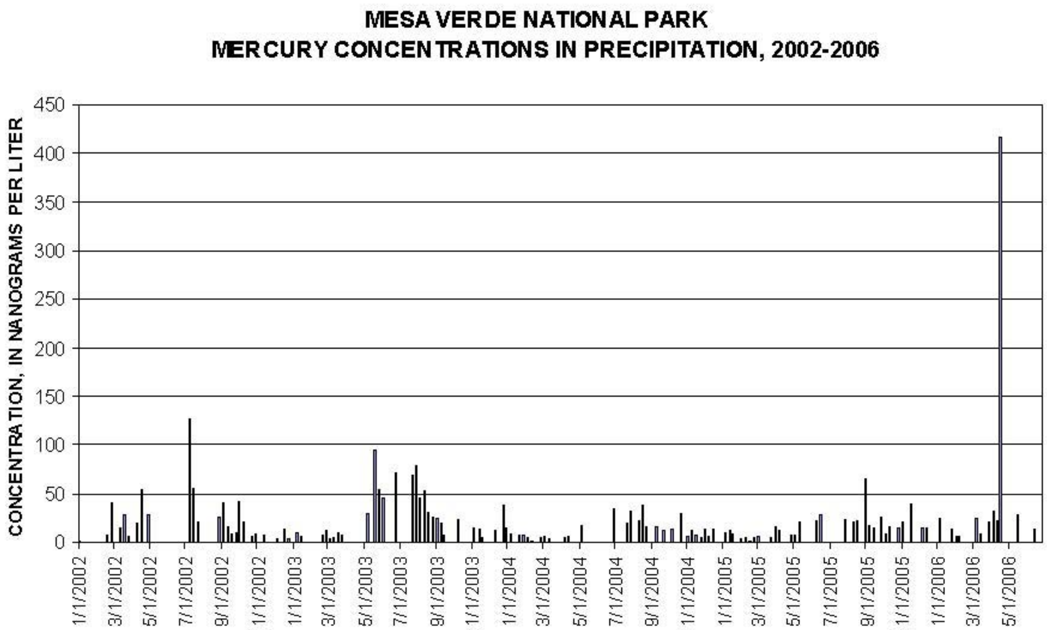
Figures



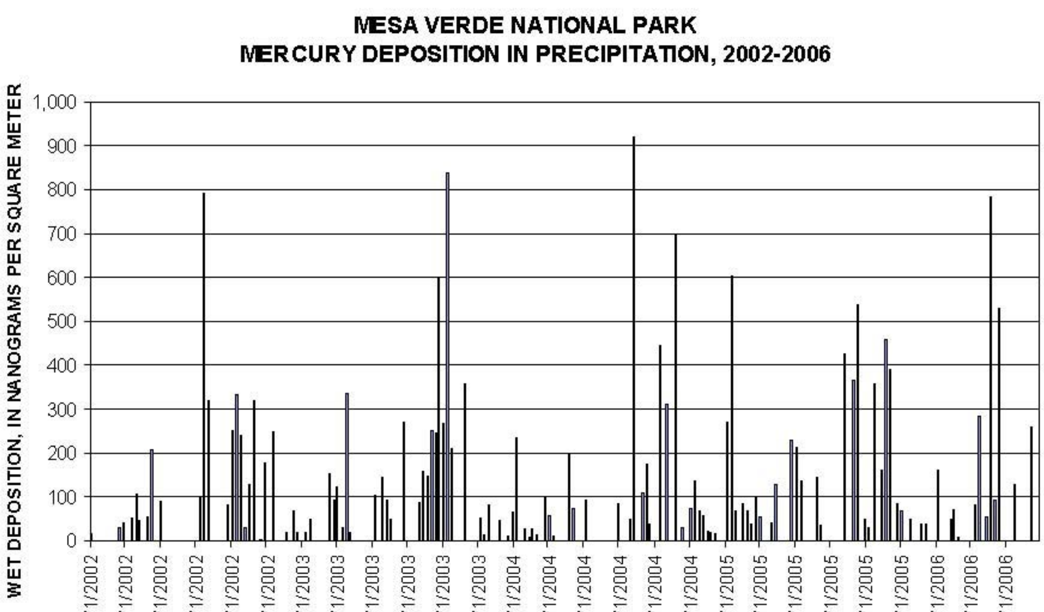


Figure 1. Concentrations and wet deposition of mercury at Mesa Verde National Park, 2002-2006. Data are from the National Atmospheric Deposition Program, Mercury deposition Network.

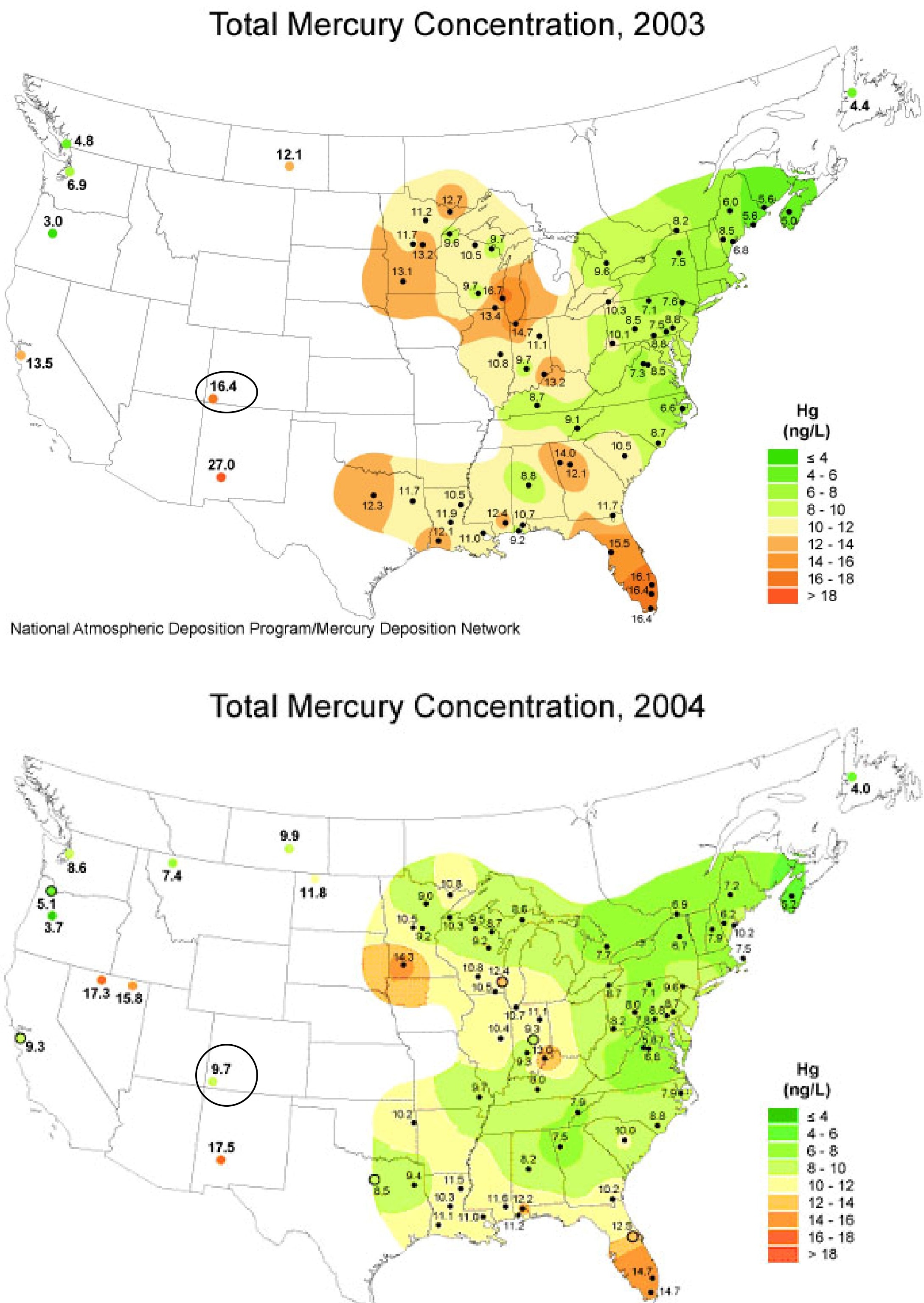
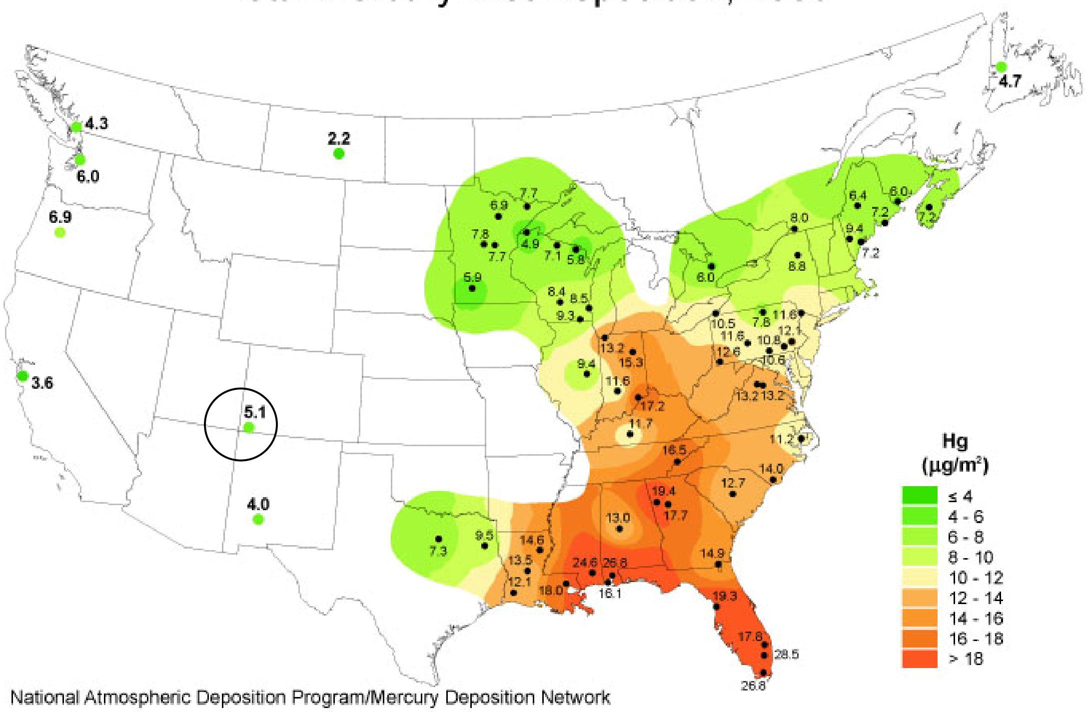


Figure 2. Volume-weighted mean concentrations of mercury in wet deposition at MDN monitoring stations across the United States for 2003 (top) and 2004 (bottom). Mesa Verde National Park is circled.

The years 2003 and 2004 represent “high” and “low” average annual concentrations for the Park’s short data record, 2002-2006.

Total Mercury Wet Deposition, 2003



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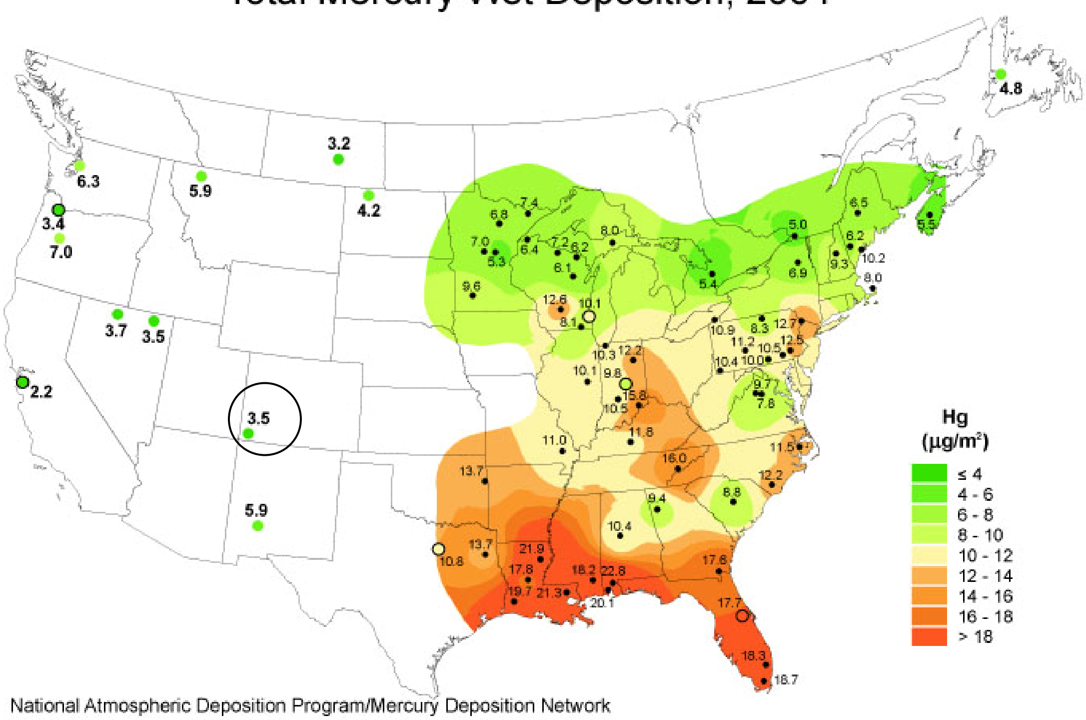

Figure 3. Total mercury wet deposition at MDN monitoring stations across the United States for 2003 (top) and 2004 (bottom). Mesa Verde National Park is circled. While concentrations are high (Figure 2), total wet deposition of mercury is low to moderate due to low precipitation amounts at Mesa Verde.

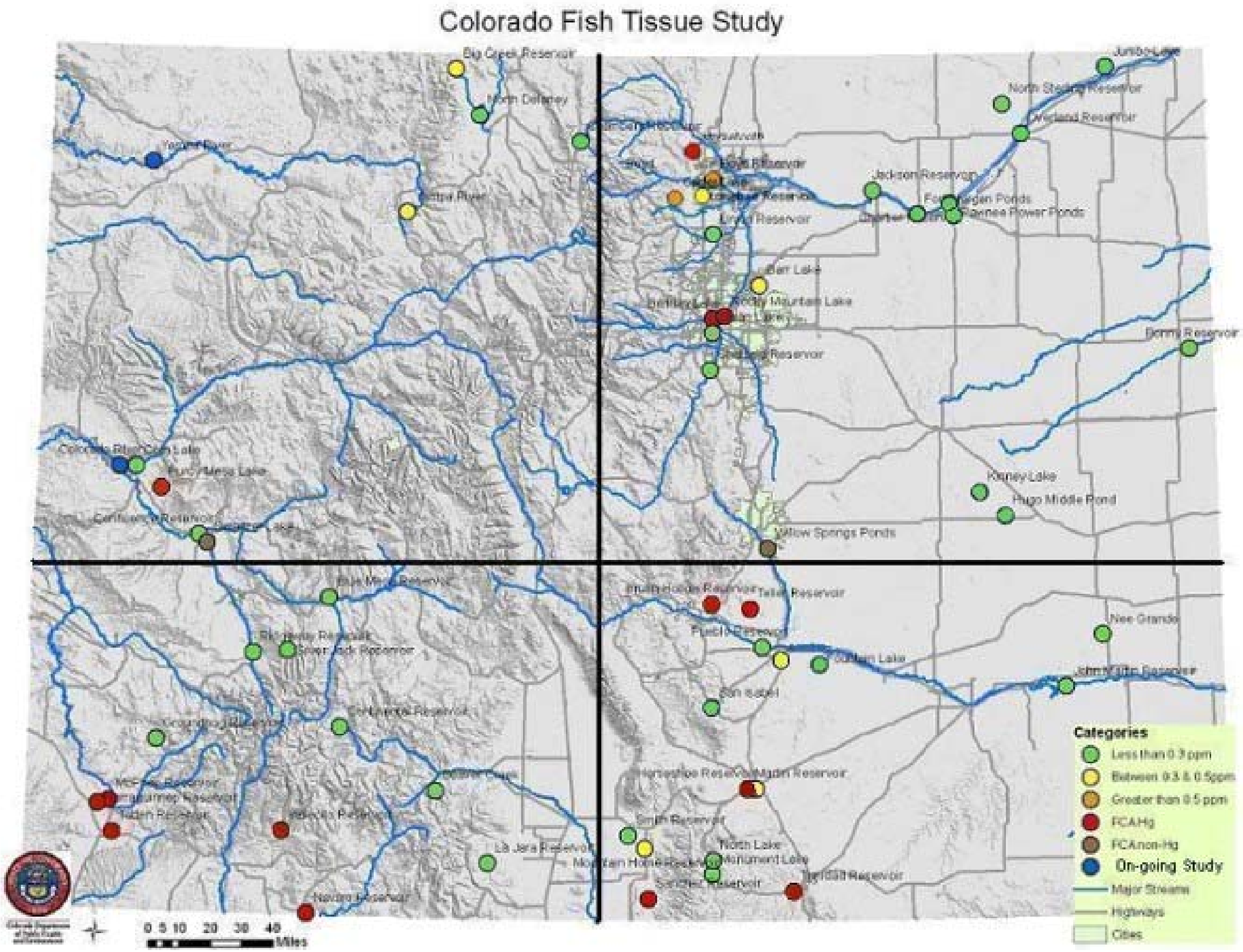

Figure 4. Results of a study by the Colorado Department of Public Health and Environment (CDPHE) measuring mercury concentrations in fish tissue in selected water bodies. The sites marked in red already have consumption advisories posted on them. Advisories are triggered by having a mercury level of 0.5 parts per million or more. The sites in orange have a similar mercury concentration to the red and are in the process of having consumption advisories posted on them as well. The sites marked in yellow have mercury levels between 0.5ppm and 0.3ppm. These are water bodies that the CDPHE is keeping a close watch on, although they are not recommending restricting consumption. The sites marked in green have mercury concentrations below 0.3ppm. The green sites are also not recommended for restricted consumption. Figure from CDPHE's Colorado Fish Tissue Study, http://www.cdphe.state.co.us/wq/FishCon/analyses/index.html.

Atmospheric Deposition of Nitrogen and Sulfur Compounds

Background:

Rationale:

Nitrogen (N) is an essential nutrient, but in elevated amounts it can cause harmful effects to ecosystems and human health. In areas with minimal human development, N in air deposition is a major contributor to N inputs to ecosystems, including surface waters. Air deposition includes wet deposition received with precipitation, but also includes dry deposition of gases and aerosols, through fall deposited under forest canopies, and condensation of cloud and fog. Atmospheric N mainly is deposited as nitrate, nitric acid, ammonium, and dissolved organic nitrogen. Key anthropogenic sources include nitrogen oxides (NOx) emitted from fossil fuel burning and ammonia volatized from fertilizer and animal wastes. NOx also will react with volatile organic compounds to form ozone (see ozone sub-chapter). Increased deposition of atmospheric N can result in high levels of nitrate in surface and ground water, shifts in species, decreased plant health, and eutrophication (i.e., fertilization) of otherwise naturally low-productivity ecosystems. Both N and sulfur (S) oxides can form “acid rain” and lead to acidification of surface and groundwater and soils. S oxides primarily are emitted to the atmosphere by burning of fossil fuels.

Atmospheric deposition of S has decreased at many monitoring stations in the USA, especially in the eastern portion, since the implementation of the Clean Air Act Title IX Amendments. Despite a few locations with slight increases in S, amounts and concentrations of sulfate in wet deposition generally are low in the western USA. In contrast, concentrations of nitrate and ammonium in wet deposition have increased at some monitoring stations in the USA, including many in the western portion (Figures 1-3).[1, 2]

Harmful ecological effects of elevated N deposition have been documented in the western United States in regions downwind of emissions hotspots, including both high and low-elevation ecosystems[3]. These effects include high nitrate concentrations in streams and lakes, reduced clarity of lakes, altered and less diverse aquatic algal and terrestrial plant communities, loss of N from soils via leaching and gas flux, increased invasive species, changed forest carbon cycle and fuel accumulation, altered fire cycles, harm to threatened and endangered species, and contribution to regional haze and ozone formation[3]. In the Colorado Front Range, including the east side of Rocky Mountain National Park, harmful ecosystem effects attributed to increased N deposition specifically include: chronically elevated levels of nitrate in surface waters, altered types and abundances of aquatic algal species (diatoms), elevated levels of N in subalpine forest foliage, long-term accumulation and leaching of N from forest soils, and shifts in alpine plants from wildflowers to more grasses and sedges[3,4,5]. Hindcasting of deposition trends estimate that the harmful effects in the CO Front Range began when N in wet deposition increased above the 1.5 kg/ha/yr threshold[6]. An ecological critical load is the quantitative estimate of an exposure to one or more pollutants below which significant harmful effects on specified sensitive elements of the environment do not occur according to present knowledge[7]. Rocky Mountain National Park has adopted 1.5 kg/ha/yr of N in wet deposition as its ecological critical load[8] and the Colorado Department of Public Health and Environment’s Air Pollution Control Division is now working to reduce N deposition loads to the Park[9].

Existing N & S deposition and ecological effects data for the Four Corners and San Juan Mountain region:

Currently, monitoring stations for N, S, and H+ in wet deposition exist at Mesa Verde National Park (since 1981), Molas Pass (since 1986), and Wolf Creek Pass (since 1992) as part of the National Atmospheric Deposition Program (NADP)[10]. Dry deposition of N and S, which is especially important in arid regions (Fenn et al. 2003), has been monitored since 1995 at Mesa Verde NP as part of the Clean Air Status and Trends Network (CASTNet). Concentrations of airborne aerosols such as ammonium nitrate and ammonium sulfate are reported as part of the Interagency Monitoring of Protected Visual Environments (IMPROVE) program at Mesa Verde National Park and a site near Durango Mountain Resort (Weminuche Wilderness).

Trends of sulfate concentrations in wet deposition show either a decrease over time or no change at monitoring stations in the vicinity of the Four Corners region. Conversely, trends of nitrate and ammonium concentrations in wet deposition appear to be stable or increasing (Figure 4)[10,11]. In general, N in wet deposition in the Four Corners and San Juan Mountain region currently is at or above the 1.5 kg/ha/yr ecological critical load discussed above for

Rocky Mountain National Park. Dry deposition data from Mesa Verde NP indicate that, for the period 1997-2000, dry deposition contributed about half of the total inorganic nitrogen deposition and about one-third of the total sulfur deposition. The short data record is insufficient to detect trends over time for dry deposition. Model simulations of total wet plus dry deposition of N in the western United States indicate a possible hotspot for N deposition in SW Colorado (Figure 5)[12].

Inorganic water chemistry for Wilderness Lakes has been collected by the USDA-National Forest Service and US Geological Survey and over 15 years of data have accumulated for some lakes. While some of this data has been compared to high-elevation lake water chemistry in other regions of Colorado and Wyoming[13], a full analysis has not been completed. Furthermore, the data are insufficient to detect potential changes to lake biology.

Data Gaps: While data for N in wet deposition exist from multiple sites in the region, dry deposition is studied only at Mesa Verde National Park, which does not represent higher-elevations common near the Four corners region. Data concerning ecological effects of N deposition are very sparse for both high and low elevations and the limited data that do exist have not been analyzed adequately. No data exists for N and S deposition in the vicinity of emission sources. For example, no monitoring of N and S in wet or dry deposition occurs in NW New Mexico with the exception of Bandelier National Park.

Suggestions for Future Monitoring Work:

C. Continue monitoring for N, S and H+ in wet deposition via the NADP at the Molas Pass, Wolfe Creek Pass and Mesa Verde National Park sites. Consider adding a site closer to emissions sources in NW New Mexico.

D. Initiate long-term monitoring / modeling of N and S in dry deposition via the Clean Air Status and Trends Network (CASTNet) at a site such as Molas Pass, which is at higher elevation than the one existing site at Mesa Verde NP. Consider adding an additional site closer to emissions sources in NW New Mexico.

E. Complete a full analysis of existing Wilderness Lakes data, including spatial and temporal trends and correlation of measurements with watershed or lake characteristics.

F. Support a suite of ecological studies in order to measure potential harmful effects of N deposition on natural resources across an elevation gradient. The studies should include an observational component aimed at documenting changing ambient conditions, but experimental manipulations should also be used to understand cause and effect relationships in addition to potential future responses. These studies should be modeled after those conducted in the Colorado Front Range, California, etc. (see Fenn et al. 2003)[3].

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6. Baron, JS. 2006. Hindcasting nitrogen deposition to determine an ecological critical load. Ecological Applications 16:433-439. http://www.esajournals.org/pdfserv/i1051-0761-016-02-0433.pdf; http://www.cdphe.state.co.us/ap/rmnp/RMNPjillbaronusgsJune1.pdf

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8. See http://www.cdphe.state.co.us/ap/rmnp/rmnpCLLetter.pdf.

9. See http://www.cdphe.state.co.us/ap/rmnp.html.

10. National Atmospheric Deposition Program (NADP), http://nadp.sws.uiuc.edu/.

11. See http://bqs.usgs.gov/acidrain/Deposition_trends.pdf.

12. Fenn, ME, R Hauber, GS Tonnesen, JS Baron, S Grossman-Clarke, D Hope, DA Jaffe, S Copeland, L Geiser, HM Reuth, and JO Sickman. 2003. Nitrogen emissions, deposition and monitoring in the Western United States. BioScience 53:391-403. http://www.treesearch.fs.fed.us/pubs/24302.

13. Musselman, RC and WL Slauson. 2004. Water chemistry of high elevation Colorado wilderness lakes. Biogeochemistry 71: 387-414.

Figures

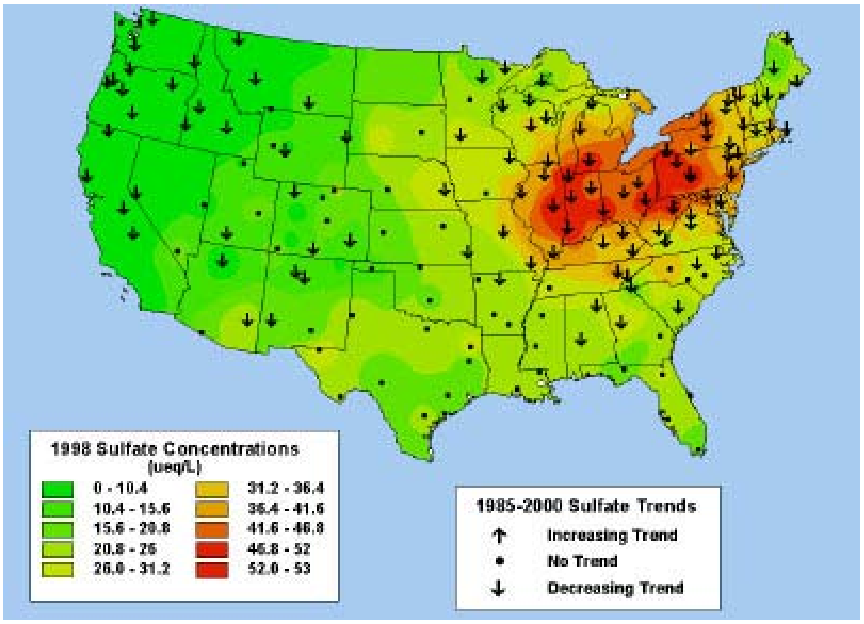


Figure 1. Trends in sulfate concentrations in wet deposition, 1985-2000. Sulfate concentrations are low in the Four Corners region and either show no trend or a decreasing trend over time[2]

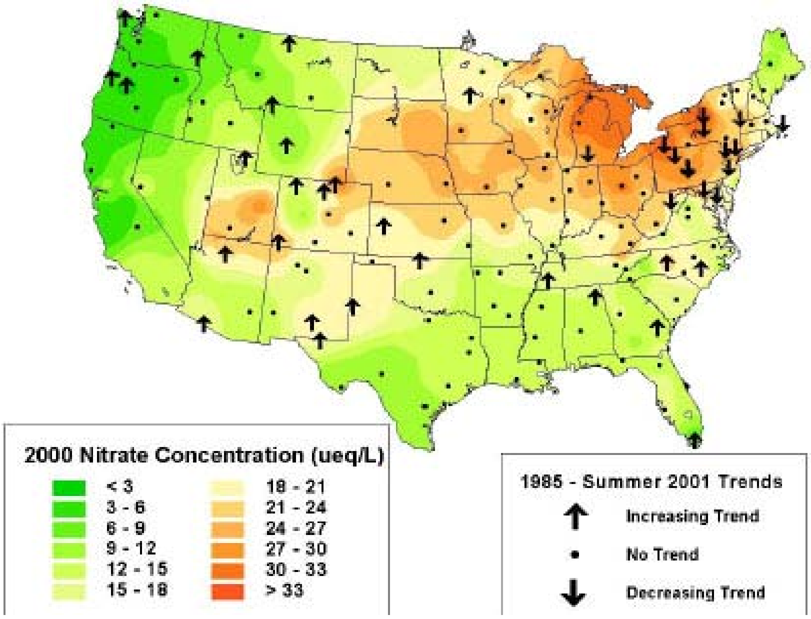


Figure 2. Trends in nitrate concentrations in wet deposition, 1985-2001. Nitrate concentrations are moderate in the Four Corners Region and show either no trend or an increasing trend over time.[2]

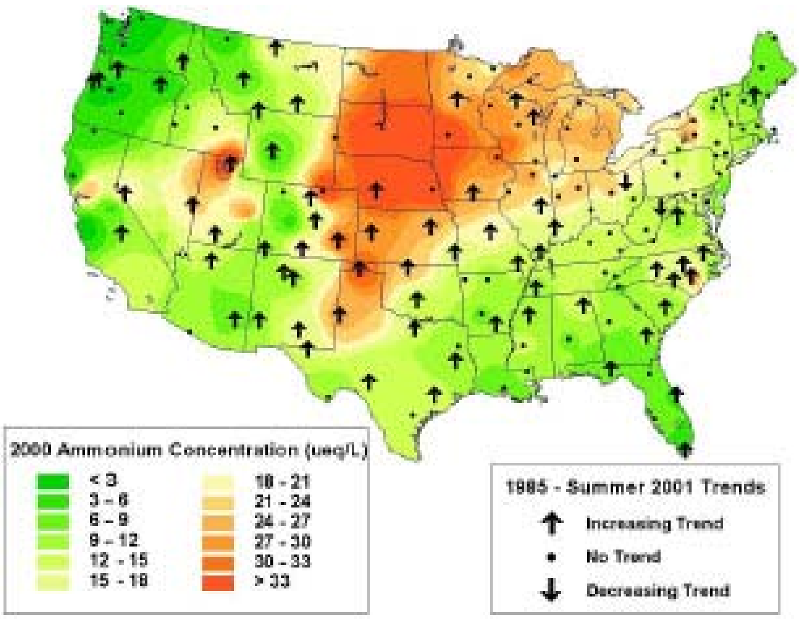


Figure 3. Trends in ammonium concentrations in wet deposition, 1985-2001. Ammonium concentrations are low in the Four Corners Region but show an increasing trend over time.[2]

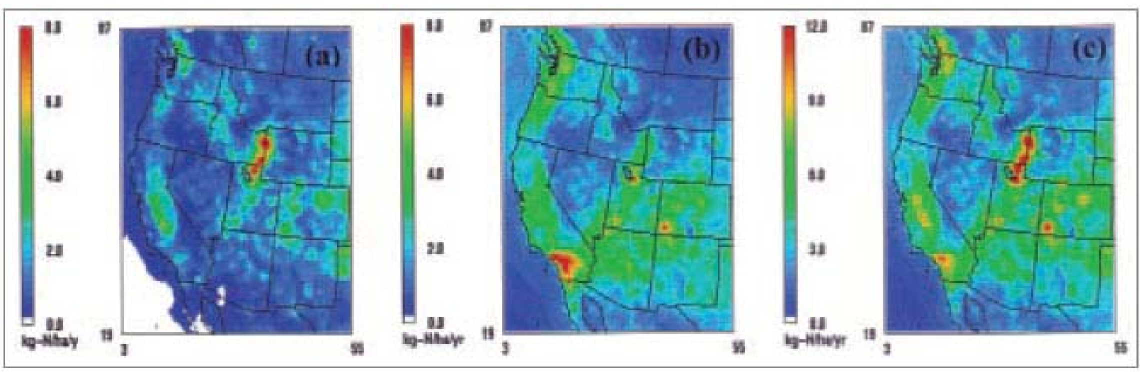
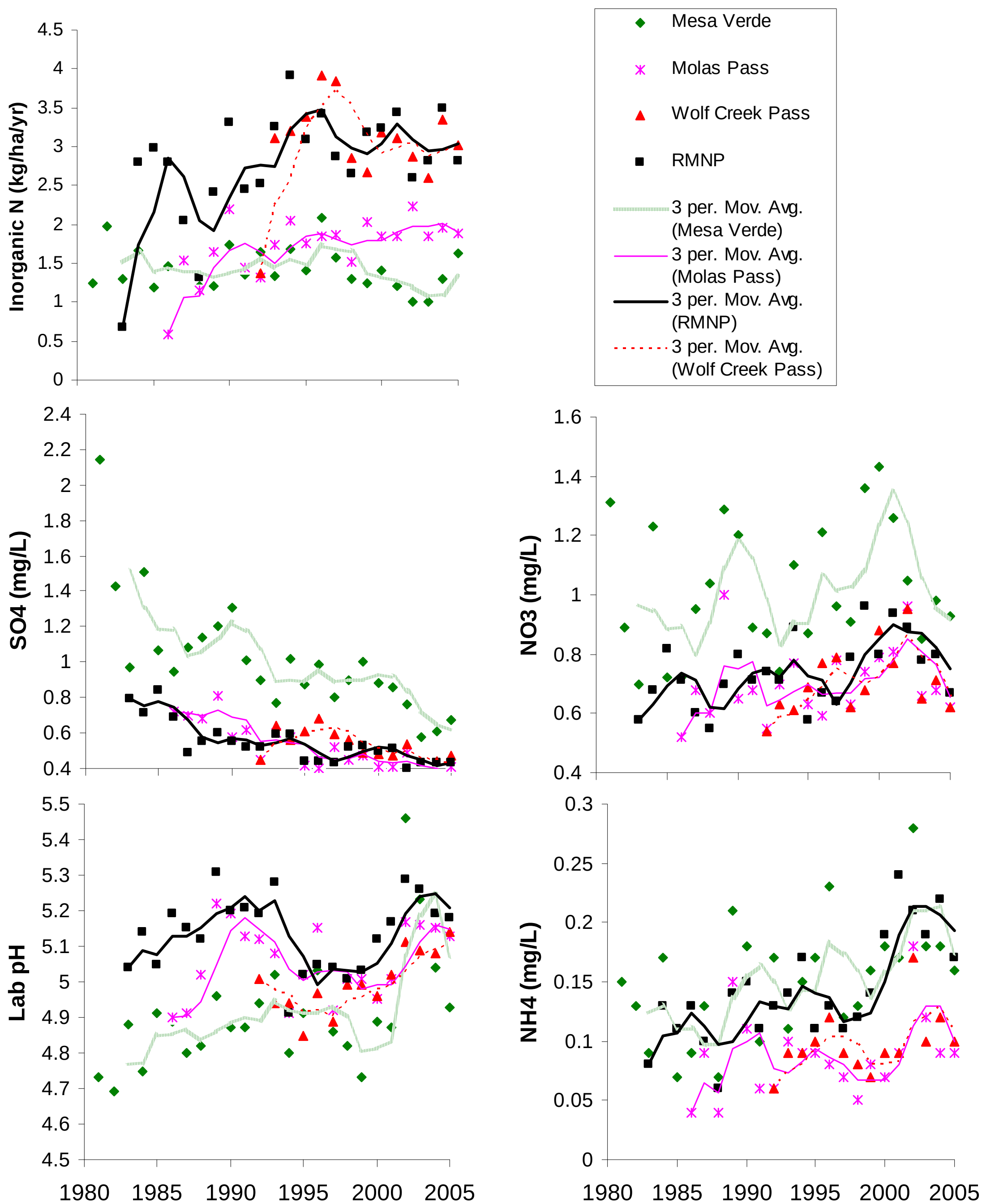


Figure 4. Model-simulated annual nitrogen deposition (kg/ha/yr) in the western United States in 1996 for (a) total wet and dry deposition of N from ammonia and ammonium, (b) total wet and dry deposition of N from nitric oxide, nitrogen dioxide, nitric acid, and nitrate, and (c) total N deposition calculated as the sum of (a) and (b).[13]

Figure 5. Annual averages of total inorganic nitrogen, pH, and sulfate nitrate, and ammonium concentrations in wet deposition from Mesa Verde National Park, Molas Pass, Wolf Creek Pass, and Rocky Mountain National Park (RMNP). Concentrations are precipitation volume-weighted means. Trend lines are 3 period moving averages and are not meant to indicate presence or absence of statistical trends. RMNP is included for comparison as a location where ecological effects of nitrogen deposition are documented.



Additional figures for Mesa Verde National Park based on data from the National Atmospheric Deposition Program:

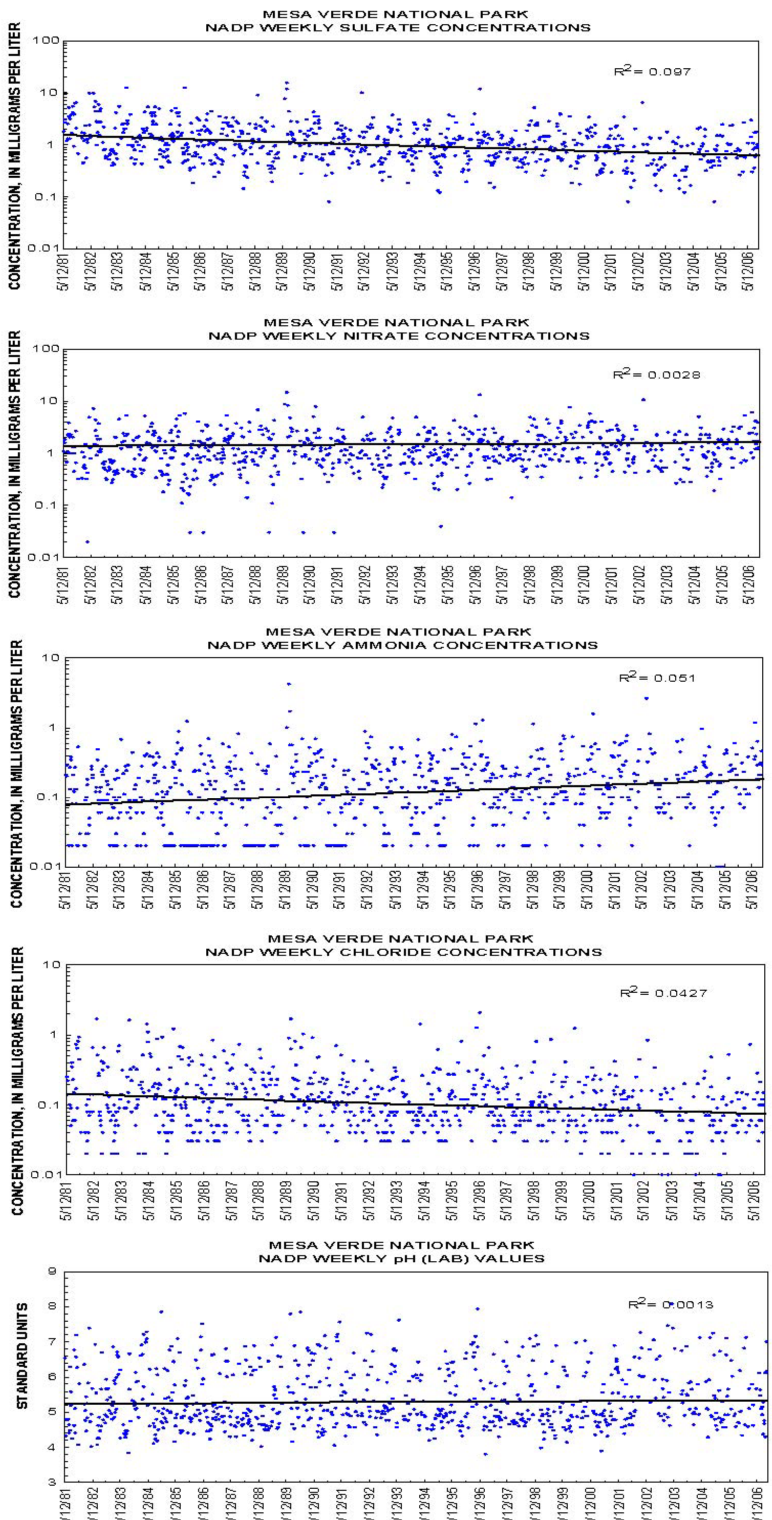


Figure 1. Weekly concentrations of selected constituents in wet deposition at Mesa Verde National Park, 1981-2006. Data are from the National Atmospheric Deposition Program.

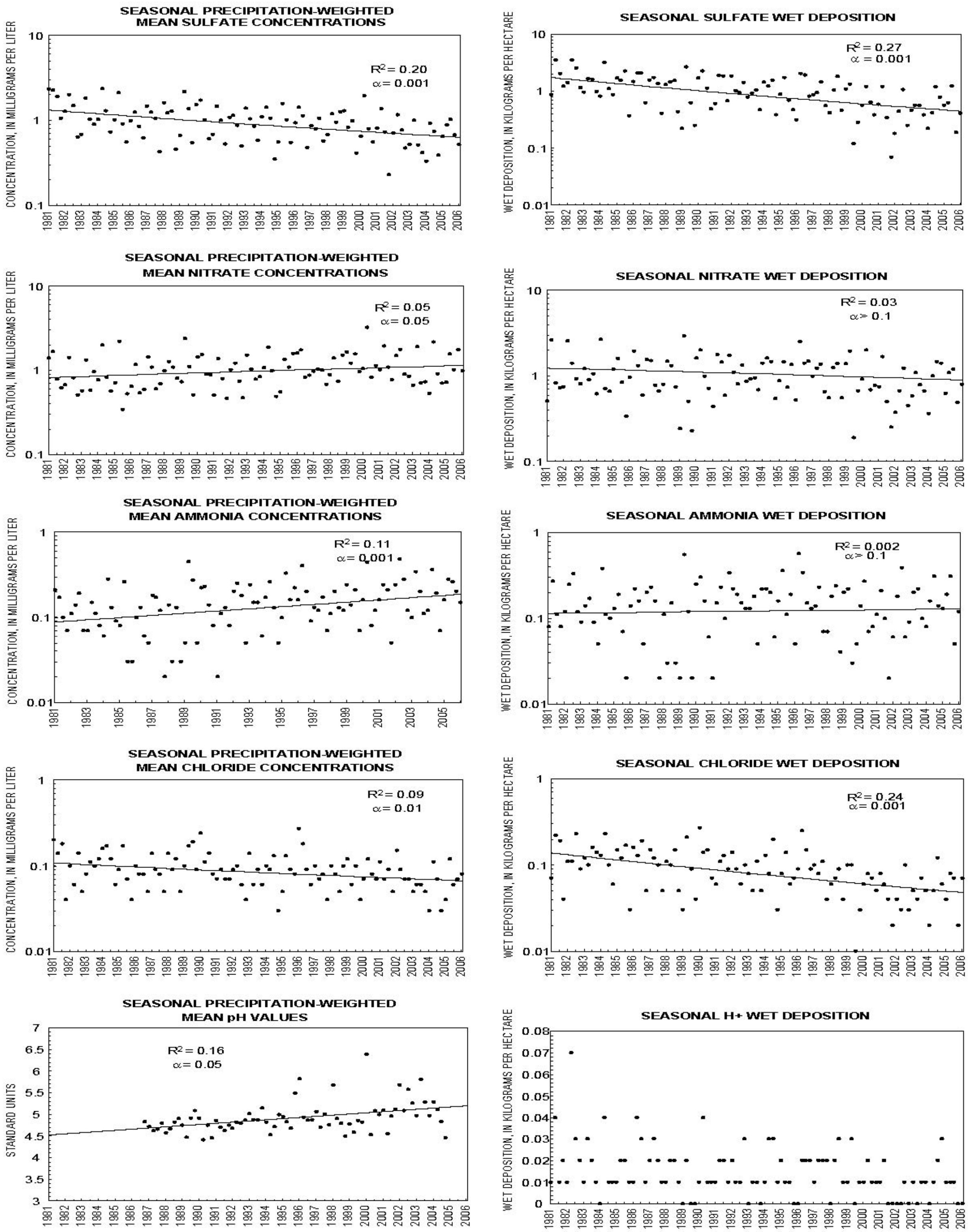


Figure 2. Seasonal concentrations and wet deposition of selected constituents at Mesa Verde National Park, 1981-2006. Data are from the National Atmospheric Deposition Program. Significance (α) from Mann-Kendall trend test.

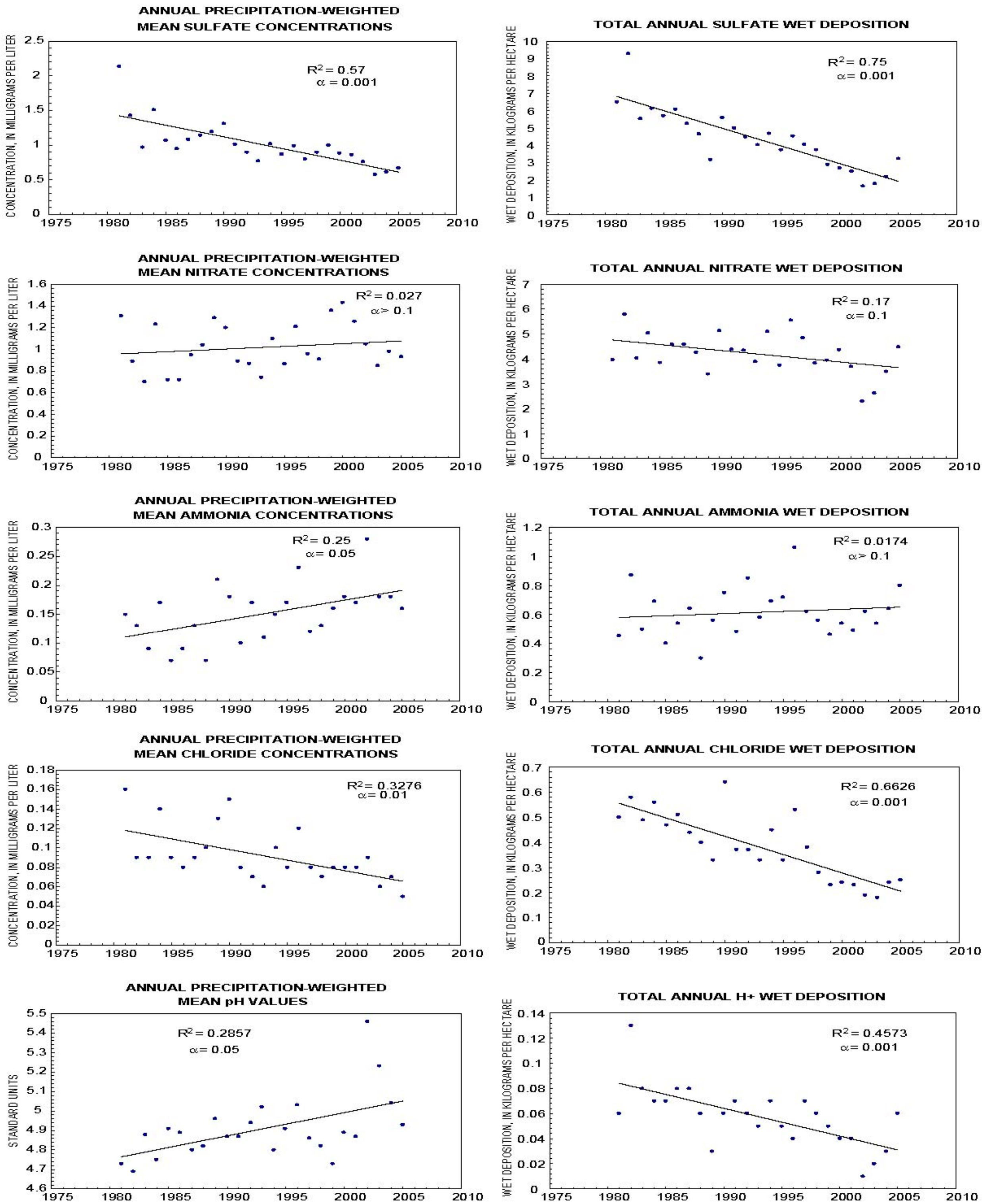


Figure 3. Annual concentrations and wet deposition of selected constituents at Mesa Verde National Park, 1981-2006. Data are from the National Atmospheric Deposition Program. Significance (α) from Mann-Kendall trend test.

Visibility

I. Background

Title 42 U.S.C. §§ 7491 and 7492 of the Clean Air Act established a national policy to study and protect visibility in Federal class I areas. It declares as a national goal "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution."[1] Of several mandatory class I areas Federal areas on the Colorado Plateau, Arches National Park, Canyonlands National Park, the Weminuche Wilderness, and Mesa Verde National Park lie within near or immediate proximity to the Four Corners Region.

Several planning and monitoring authorities have evolved from this statutory requirement, two of which are able to directly address visibility concerns in the Four Corners region. The Interagency Monitoring of Protected Visual Environments (IMPROVE) program was initiated in 1985, and has implemented an extensive long term monitoring program in the National Parks and Wilderness Areas.[2] Additionally, the Western Regional Air Partnership (WRAP) was formed in 1997 as the successor to the Grand Canyon Visibility Transport Commission, and promotes the implementation of recommendations that were made in the previous commission.[3] Specifically, the WRAP partnership is implementing a regional planning process to improve visibility in all western Class I areas "by providing the technical and policy tools needed by states and tribes to implement the federal regional haze rule."[4]

EPA issued the final Regional Haze Rule on April 22, 1999.[5] "The rule requires the states, in coordination with the Environmental Protection Agency, the National Park Service, U.S. Fish and Wildlife Service, the U.S. Forest Service, and other interested parties, to develop and implement air quality protection plans to reduce the pollution that causes visibility impairment."[6] This regulation is also anticipated to have the additional benefits of improving visibility outside of class I areas, as well as ameliorating the health impacts associated with fine particulates (PM 2.5).[7]

II. What affects visibility and how is it monitored?

The interaction between certain gasses, particulate matter, and the light that passes through the atmosphere yields the basic processes through which visibility is affected. Gasses and *aerosols* may scatter or block sunlight through *diffraction, absorption,* and *refraction*. When sunlight encounters gasses and aerosols, it scatters preferentially as a function of the size of the particles that it encounters.[8] The relationship between particulate size and light is extremely important, as it ultimately accounts for changes in color and *haze*. Although the total mass of coarse particles (PM 10) in the atmosphere outnumbers the total mass of fine particles (PM 2.5), the finer particles "are the most responsible for scattering light" because they scatter light more efficiently, and because there are more of them.[9] Consequently, the origin and transport of fine particles (PM 2.5) is of greatest concern when assessing visibility impacts.[10]

In the most general sense, visibility is the effect that various aerosol and lighting conditions have on the appearance of landscape features.[11] While photography is the simplest method used to convey visibility impairment, it is difficult to garner quantitative information from photographs, digital pictures, or slides. Because some direct measurement of the atmosphere's optical qualities is desired, most visibility programs include a measure of either atmospheric *extinction* or *scattering*.

> The *scattering coefficient* is a measure of the ability of particles to scatter photons out of a beam of light, while the *absorption coefficient* is a measure of how many photons are absorbed. Each parameter is expressed as a number proportional to the amount of photons scattered or absorbed per distance. The sum of scattering and absorption is referred to as *extinction* or attenuation.[12] (Emphasis added.)

Extinction is measured by devices such as the *transmissometer* and *nephelometer*. Most monitoring programs use combinations of these devices to measure extinction and scattering. Extinction is usually described in terms of *inverse megameters* (Mm^{-1}), and is proportional to the amount of light that is lost as it travels over a million meters.[13] *Deciviews* is another measurement of extinction, but which is scaled in a way that it is perceptually correct. "For example, a one deciview change on a 20 deciview day will be perceived to be the same as on a 5 deciview day."[14] Because deciviews are *scaled* so that they may describe *changes* in visibility, they must be distinguished from extinction as it can otherwise be described in inverse megameters and *visual range*.

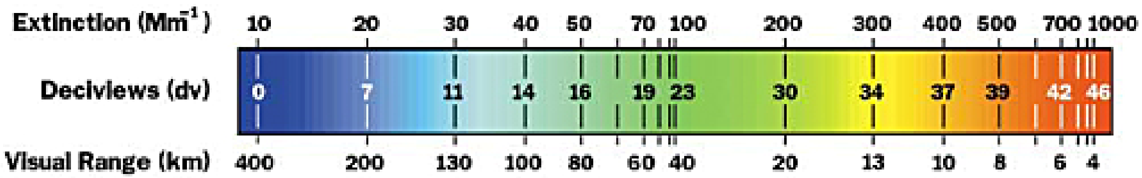


Fig. A Comparison of extinction (Mm^{-1}), deciview (dv), and visual range (km).
(Source: Malm, William C. Introduction to Visibility.)

In addition to the measurements of scattering and extinction, it is also helpful to know what materials in the air are contributing to visibility impairment. *Particle measurements* are normally made in conjunction with optical measurements "to help infer the cause of visibility impairment, and to estimate the source of visibility reducing aerosols."[15] The size and composition of particles are the most commonly identified characteristics that are used in visibility monitoring programs. Additionally, "particles between 0.1 to 1.0 microns are most effective on a per mass basis in reducing visibility and tend to be associated with man-made emissions."[16] These fine particles are usually grouped under the category PM 2.5, which refers to particles that are less than 2.5 microns large. (As discussed earlier, PM 2.5 particles are in general the most effective in scattering light due to their small size.) "The IMPROVE fine particle modules employ a cyclone at the air inlet which spins the air within a chamber. Fine particles are lifted into the air stream where they are siphoned off and collected on a filter substrate for alter analysis."[17] Once the size of particles has been measured, they are speciated by composition. The identification of sulfates, nitrates, organic material, elemental carbon (soot) and soil "helps determine the chemical-optical characteristics and the ability of the particle to absorb water (RH effects) and is important to separate out the origin of the aerosol."[18]

> A visibility impairment value is calculated for each sample day. To get a valid measurement, all four modules must collect valid samples. The regional haze regulations use the average visibility values for the clearest days and the worst days. The worst days are defined as those with the upper 20% of impairment values for the year, and the clearest days as the lowest 20%. The goal is to reduce the impairment of the worst days and to maintain or reduce it on the clear days.[19]

For data to be considered under the regional haze regulations, it must meet the minimum criteria for the number of daily samples needed in a valid year: 1.) 75% of the possible samples for the year must be complete; 2.) 50% of the possible samples for each quarter must be complete; 3.) No more than 10 consecutive sampling periods may be missing.[20]

As noted above, the filter analysis provides the concentrations and composition of atmospheric particles. The *source contribution* to visibility impairment can be indicated from the analysis of trace elements:

vanadium/nickel	»	petroleum-based facilities, autos
arsenic	»	copper smelters
selenium	»	power plants
crustal elements	»	soil dust (local, Saharan, Asian)
potassium (nonsoil)	»	forest fires[21]

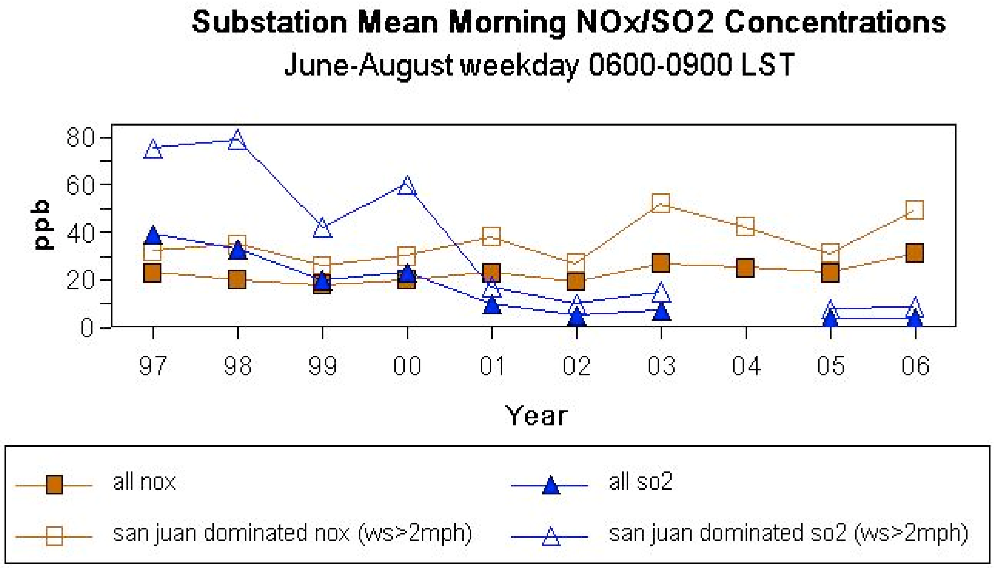
III. Visibility in the Four Corners

Currently, there are four sites within the Four Corners region that monitor visibility: Mesa Verde National Park, the Weminuche Wilderness (near Purgatory,) the Shamrock Mine (southeast La Plata County,) and Canyonlands National Park. Of these four sites, only the Forest Service monitoring station at the Shamrock Mine records images, and is included in IMPROVE's optical and scene monitoring network. Additionally, because the Canyonlands site lies on the margin of the Four Corners Region, and it is also located at a comparatively lower elevation north of the Blue Mountains, it may not serve as the best indicator of visibility trends in the Four Corners proper.

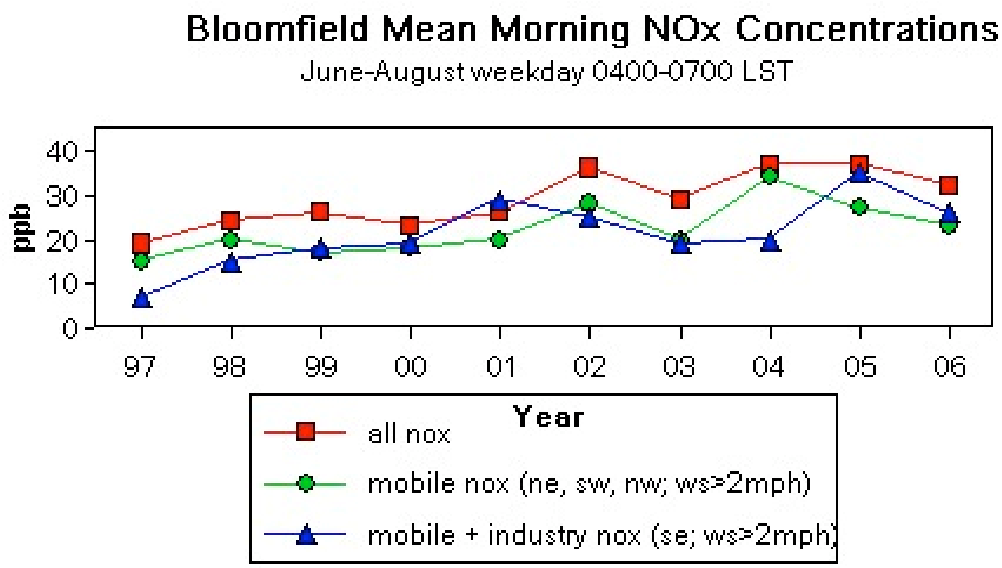
Preliminary analysis of deciview trends at Mesa Verde, and also of visibility-impairing gasses and particulates as monitored at other sites, does not reveal a clear trend of how visibility might be changing in the Four Corners. This appraisal is not concomitant with the observations of many area residents. It may be indicative of monitoring gaps that exist in the Four Corners, and it has led to the perception by members of the Task Force Monitoring Group that a comprehensive, detailed analysis of all available data regarding visibility is greatly needed.

Despite that ambiguity, however, there are a few details worth noting. In September of 2005, the Interim Emissions Workgroup of the Four Corners Air Quality Task Force recommended that an ambient monitoring program for gaseous ammonia be initiated in the Four Corners region. The purpose of this program is to set a current baseline of ambient gaseous ammonia concentrations in the Four Corners, that can be compared to monitored values in approximately 3-5 years after the implementation of NOx controls (e.g. NSCR) on oil and gas equipment. The use of NSCR may increase ammonia emissions in the area, but these emissions have not been quantified and may or may not significantly affect visibility. Ammonia at high enough concentrations can contribute to worsening visibility by forming PM 2.5 ammonium nitrates and ammonium sulfates.

Additionally, the implementation of new SO_2 controls at the San Juan Generating Station in 1999 has successfully reduced SO_2 emissions in the area. Because of the high impact that SO_2 can have upon visibility, that reduction has likely made a positive impact upon visibility conditions in the Four Corners. However, changes in monitoring conditions at San Juan Substation have not been limited to a decrease in SO_2. Concurrently, it appears that NOx concentrations have risen, and now dominate over SO_2:



For the same time period, similar increases in NOx have been observed in Bloomfield, and it appears that NOx may be slowly increasing as a regional trend:

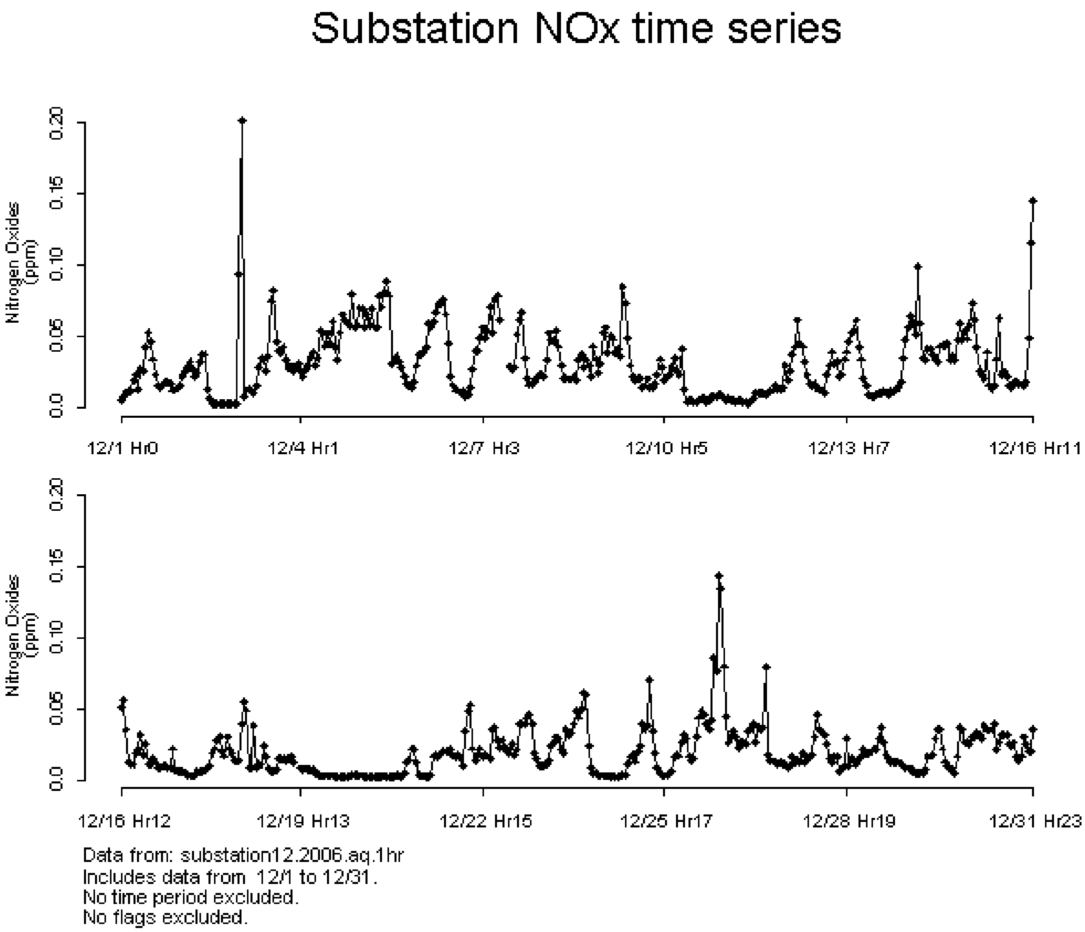


Many citizen's accounts on deteriorating visibility in the Four Corners have centered upon wintertime episodes. The ways in which seasonal differences may impact visibility is very important. In the summertime, the "confining layer" of the atmosphere, which generally holds pollutants below a certain altitude, is much higher. Additionally, the extra heat associated with warmer seasons allows the atmosphere to move and mix more readily. The result is that, in the summertime, visibility-impairing pollutants can mix more easily, and dilute within in a greater vertical distance. Conversely, in the wintertime, that confining layer is usually much lower (thus the prevalence of wintertime inversions.) In colder seasons, the atmosphere does not move or mix as easily. Therefore, generally, wintertime pollutants are held closer to the ground level, and they cannot readily dilute into the upper atmosphere. Given this effect, the same level of regional emissions year-round will likely be more noticeable in the winter as *layered haze*. The addition of rising emissions levels will compound this effect in the wintertime.

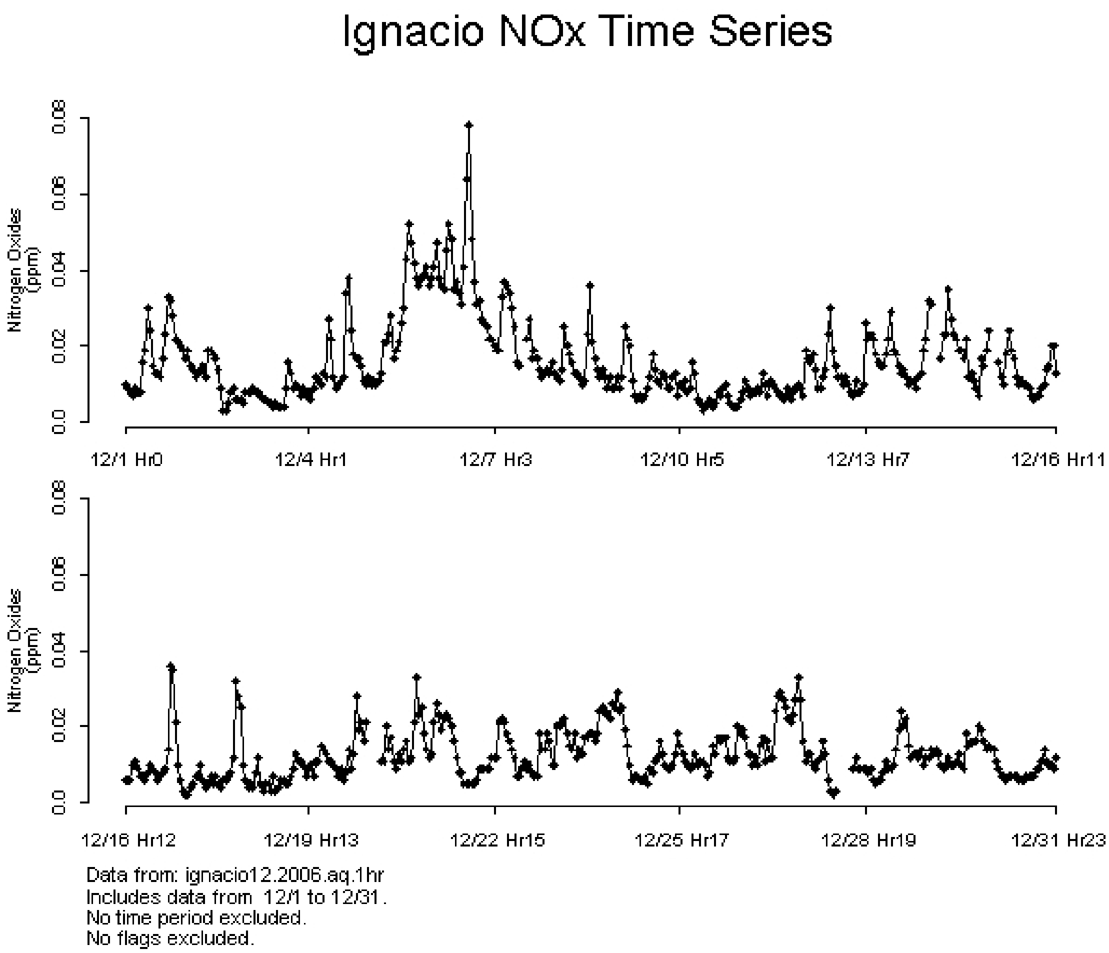
Wintertime haze near Kline, Colorado. 12/05/2006. *See also*: A Resident's Observation of Visibility, this section.

Excellent visibility, photo taken one mile west of previous photo. 10/21/2006.

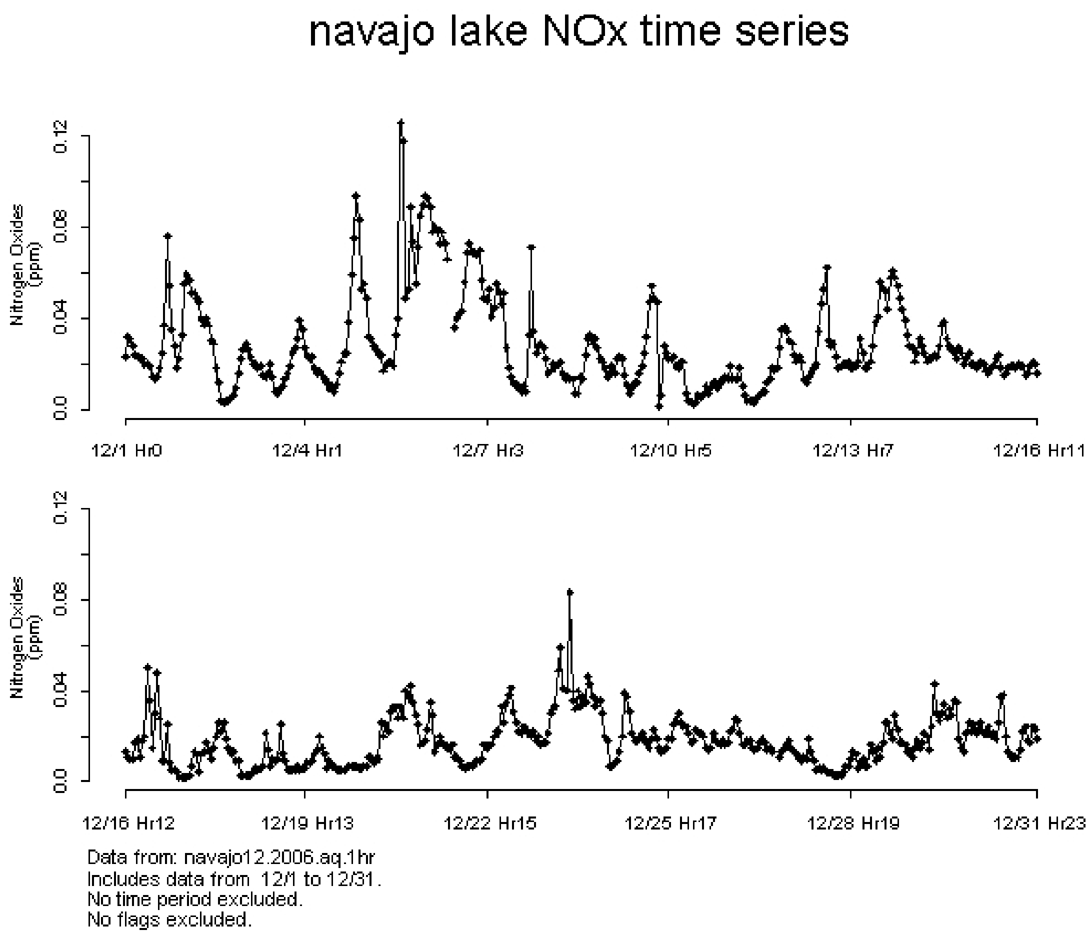
The considerations outlined above reasonably lead to the hypothesis that citizens' accounts of deteriorating visibility, as they are specific to wintertime episodes, may be partially caused by increasing NOx emissions. For an initial test of this hypothesis, we may review what NOx concentrations existed in the region at the time of the 12/05/2006 photograph:



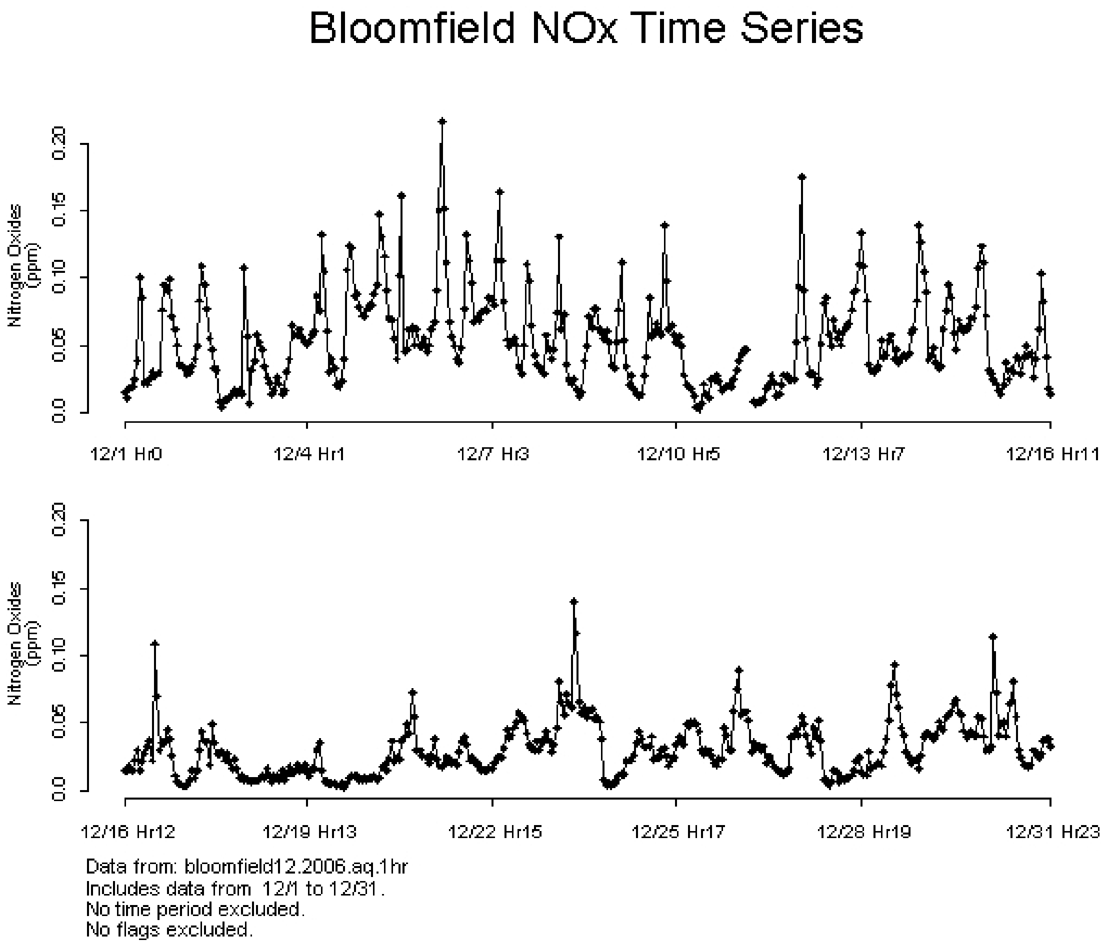
Elevated NOx concentrations existed at the San Juan Substation, with the most pronounced event occurring approximately 48 hours before the 12/05/2006 photograph.



Elevated NOx concentrations existed at the Ignacio monitoring site approximately 24 hours after the 12/05/2006 photograph.



Elevated NOx concentrations existed at the Navajo Lake monitoring site, with the most pronounced concentrations occurring on 12/05/2006.



Elevated NOx concentrations existed at the Bloomfield monitoring site, with the most pronounced concentrations occurring within 24 hours of the 12/05/2006 photograph.

It appears that NOx concentrations were a contributing factor behind the visibility impairment episode documented in the 12/05/2006 photograph. These preliminary observations raise a number of additional considerations. First, there exists a great value in the photographic documentation of visibility. These elevated NOx concentrations might not have been considered if one were to only examine particulate data over a given time period. *Visual observations*, although subjective, provide the first clue that will lead the inquisitor to examine specific episodes and time periods. The contemplation of criteria such as color, location, and the *expanse* of impairment episodes considers the *regional nature* of visibility impairment in a way that no site-specific particulate measurement can do. In a sense, visual accounts and photographic documentation is a *top-down* approach that reveals what data needs to be specifically considered, and where additional monitoring would be useful.

Second, in the case of indeterminate deciview trends at Mesa Verde, the preceding discussion on photographic documentation obliges us to consider the monitoring site's location. Mesa Verde is situated upon the uppermost reaches of the *Four Corners Platform*. This geologic plateau rises above the valleys and basins of the Four Corners region, and typifies the area's rugged and varied topography. The monitoring site at Mesa Verde is located at roughly 7,200 feet above sea level, while most emissions in the region occur in the San Juan Basin to the south, at roughly 5,000 feet. (Likewise, most other emissions in the region are related to human activity, and occur in the other multiple valleys and basins that are topographically separated from the Park.) Given the occurrence of wintertime inversions and a lower confining atmospheric layer, it is entirely possible that what is observed as severe visibility impairment will not be recorded at Mesa Verde, because the monitoring site will be *above the confining layer*. The absence of photographic documentation coexistent with particulate measurements in the Park causes that data to be extrapolated from air quality within the Park itself, and it will not effectively consider what an observer might actually see as she looks across the region from that location.

It is reasonable to assume that (wintertime) visibility impairment in the Four Corners is exacerbated by the area's rugged topography, which often confines visibility impairment to within the region's numerous basins and deep valleys. Additionally, that visibility monitoring in the Four Corners which is reliant on particulate measurements is located at higher elevations, and is not likely to record events related to low confining layers and atmospheric inversions. (I.e. Mesa Verde and the Weminuche.) These locations are, however, great *vantage points* from which visibility may be observed, but they forgo this opportunity because they do not include photographic documentation. Furthermore, Canyonlands National Park is not a good location to observe visibility as it relates to the Four Corners, because it is too distant from the region. (Both the path of emissions transport and line of sight from the Four Corners to Canyonlands is blocked by the higher elevations surrounding the Blue Mountains and Bear's Ears.) That leaves only one site—the Shamrock Mine—from which visibility in the Four Corners Region can be satisfactorily observed and documented year-round.

IV. Suggestions for Future Monitoring Work

Air quality monitoring is a rather expensive operation, and so resources that might provide for saturation studies or additional permanent monitoring should be allocated in consideration of monitoring goals as a whole. However, it is still reasonable to advocate some additional monitoring of visibility, as most of the following suggestions could be incorporated into existing sites.

Last, most visibility monitoring in the Four Corners is unevenly distributed (or restricted) to Class I areas. Therefore, visibility monitoring within these Class I areas is not conducive of a regional trends assessment, especially because they are based on a very few site-specific particulate measurements. Furthermore, the regional monitoring of visibility is desirable, because it can assist with the protection of Class I areas and EPA's regional haze rule. Additionally, regional monitoring of visibility will better address the value that citizens place upon the vistas that exist outside of Class I areas, while recognizing how visibility impacts citizens' perceptions of air quality as a whole. In sum, it is highly desirable that we consider how visibility monitoring in the Four Corners region can be perfected, with the intent of making a *strong regional assessment*.

1. It is suggested that the monitoring sites at Mesa Verde and in the Weminuche resume photographic documentation.

2. Many previous studies of visibility in the Four Corners relate only to site-specific locations, and often conflict in their findings. A comprehensive assessment of historical data is needed, in order to determine regional trends or changes in visibility. Currently, it is very difficult not only to establish regional trend analyses, but also to compare them to historical baseline data.

3. Additional visibility monitoring should be established at locations in the region other than what exists in Class I areas. This additional monitoring:

1. could be incorporated into existing monitoring sites;
2. should include photographic documentation;
3. and, it should specifically consider how topographical variations impact the measurement of visibility.

4. The apparent contribution of NOx emissions to wintertime visibility impairment is recommended for further study.

V. Works Cited:

1. 42 U.S.C. § 7491 (a)(1).
2. http://vista.cira.colostate.edu/improve/ (access date 4/05/2007).
3. http://www.wrapair.org/facts/index.html (access date 4/05/2007).
4. Id.
5. http://vista.cira.colostate.edu/improve/Overview/hazeRegsOverview_files/v3_document.htm (access date 4/05/2007). *See also* http://www.epa.gov/air/visibility/program.html.

6. http://www.epa.gov/air/visibility/program.html (access date 4/05/2007).
7. http://vista.cira.colostate.edu/improve/Overview/hazeRegsOverview_files/v3_document.htm
8. (access date 4/05/2007).
9. Malm, William C. 1999. Introduction to Visibility. Cooperative Institute for Research in the Atmosphere (CIRA). Fort Collins, Colorado. P. 8.
10. Id. at 9.
11. Id.
12. Id. at 27.
13. Id.
14. Id. at 35.
15. Id.
16. Id. at 28.
17. Id. at 28, 29.
18. IMPROVE 2007 Calendar.
19. Malm at 29.
20. IMPROVE 2007 Calendar.
21. Id.
22. Id.

The complete photographic record prepared by Erich Fowler is available by contacting Mark Jones at mark.jones@state.nm.us. This is a very large file (over 100 MB).

Mitigation Option: Interim Emissions Recommendations for Ammonia Monitoring

I. Description of the mitigation option

The following mitigation option paper is one of three that were written based on interim recommendations that were developed prior to the convening of the Four Corners Air Quality Task Force. Since the Task Force's work would take 18-24 months to finalize, and during this time oil and gas development could occur at a rapid pace, an Interim Emissions Workgroup made up of state and federal air quality representatives was formed to develop recommendations for emissions control options associated with oil and gas production and transportation. The Task Force includes these recommendations as part of its comprehensive list of mitigation options.

Implement an ambient monitoring program for ammonia

C. Assess importance of ammonia to visibility
D. Visibility modeling would be more accurate if ammonia data were available
E. Ammonia emission impacts from NSCR can be better evaluated
F. US EPA Region 6 will assist with this effort

Evaluate data on ammonia emissions from engines less than 300 HP equipped with NSCR

- Testing should be done in the field
- Funding would need to be secured
- A contractor to make measurements would need to be found

II. Description of how to implement

The ambient monitoring program for ammonia would be conducted under the auspices of EPA Region 6. The appropriate agencies to implement this are EPA Region 6 and the New Mexico and Colorado departments of environmental quality. Collecting data on ammonia emissions from engines less than 300 HP would be voluntary and funding would need to be secured.

III. Feasibility of the Option

The technical feasibility of the ambient monitoring has already demonstrated. Specifically, the technical feasibility of measuring ammonia emissions from engines with NSCR has been demonstrated as part of a research project initially started by Colorado State University. However the exact methodology is not yet chosen. The environmental feasibility is negligible since only samples are collected. The economic feasibility depends on finding someone to pay for the sampling program

IV. Background data and assumptions used

The ambient monitoring would be conducted either by collecting samples or by real time analysis depending on equipment selected. Approximate measurements can be made using sampling tubes similar to Draeger tubes. The assumption is that a baseline ammonia level should be established and that potential increases may be observed because of the use of large numbers of rich burn engines with NSCR catalysts.

This methodology is already being tested in the Colorado State University research project.

V. Any uncertainty associated with the option

The cost of the ambient monitoring program is not well established because the monitoring technology is not fully specified. Therefore, there is some uncertainty associated with this option.

VI. Level of agreement within the work group for this mitigation option

To be determined.

VII. Cross-over issues to the other source groups

This mitigation option would cross over to the Oil and Gas work group.

RESOLUTIONS

Introduction

In January, 2005 the Cortez/Montezuma League of Women Voters Air Quality Committee began its study of air quality issues in Montezuma County. It became evident that to study air quality we needed facts. To gain facts we needed monitoring. A committee was formed consisting of the following League of Women Voters members: Sylvia Olivia-air quality consultant, Judy Schuenemeyer-lawyer, Eric Janes-water quality expert, Jack Schuenemeyer-statistician, Mary Lou Asbury-spokesperson. The committee met frequently and came up with a plan of action.

We invited Mark Larson, our state representative and Jim Isgar, our state senator, to a League of Women Voters meeting. Sylvia showed the plume model (a computer model of the plume movement from the areas existing power plants and the proposed 2 new power plants). We discussed the need for monitoring in the Montezuma Valley. Both agreed to take our concerns to the Colorado Legislature and the Colorado Health Department. The ground work was laid.

The committee then met in Durango with the Congressional staff of Senator Ken Salazar and Representative John Salazar. To show governmental and community support for air monitoring we decided we needed to take resolutions to the Montezuma County Commissioners, Cortez City Council, and Mancos and Dolores Town Boards. A power point presentation with facts on ozone and mercury was decided upon.

The committee met over a period of 2-3 months to put the finishing touches on the power point, commentary and resolutions. Presentations were scheduled starting in June,2005.

Sylvia Olivia, Eric Janes, Judy and Jack Scheunemeyer and Mary Lou Asbury were in attendance for all presentations. Questions were answered to the satisfaction of all. Resolutions were signed in support of getting air monitoring, data collection and analysis from the EPA, BLM-CO, BLM-NM, and USGS. These have been mailed to all interested parties including all the Colorado Congressional Delegation and to our state representative and senator. The need was recognized, but the funding has been problematic.

The committee has continued to do presentations to various groups to gain support for the need for air monitoring in the Montezuma Valley. The need becomes more critical as final plans are being made to construct a new power plant. Also, more coal bed methane wells are proposed in the San Juan Basin and throughout the Four Corners Region.

There are many health issues and lifestyle concerns which require an air quality monitoring system. The League of Women Voters resolutions help show concern from representative government. The resolutions follow from the Montezuma County Commissioners, Cortez City Council, Mancos Town Board and Dolores Town Board.

City of Cortez
Resolution No. 17, Series 2005
United States Environmental Protection Agency

Whereas, the City Council of the City of Cortez, Montezuma County, Colorado is interested in a healthy environment and clean air for citizens of the City, and

Whereas, concerns are being raised by City residents about the possible effects on the City environment and air quality by the proposed Desert Rock Energy Project to be built on Navajo Nation lands in the State of New Mexico, and

Whereas, Sithe Global Power, Inc. of Houston Texas and the Dine Power Authority have begun planning for two 750 MW coal-fired electric generating units and associated facilities for the proposed plant, and

Whereas, the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution, such as that emitted from the San Juan and Four Corners electric generation plants in New Mexico, greatly exceeds that emitted from all sources in the County, and

Whereas, mercury is a known pollutant emitted from coal-fired electric power generating plants and recent studies have shown that mercury can cause neurological damage and is especially harmful to developing fetuses and children, and

Whereas, the second highest concentrations of mercury in rain and snow recorded for any location in the western United States for the past two years have been found in Mesa Verde National Park, and

Whereas, State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury, and

Whereas, City residents with respiratory problems such as asthma are experiencing additional health problems on days when air pollution appears to be higher, and

Whereas, Mesa Verde National Park is the only known site for air quality data collection in Montezuma County and may not adequately provide a basis for characterizing air for the remainder of the County, including the City of Cortez, and

Whereas, additional monitoring sites are needed in the County to measure current levels of air pollution in order to assess the additional impact on air quality of the proposed power plant.

Now Therefore Be It Resolved by the Cortez City Council,

That, the Council finds that additional air quality monitoring sites are needed elsewhere in Montezuma County to adequately assess the impact of air pollution from sources outside the State of Colorado on the health of City residents, and

Further that, the Council requests that the Regional Administrator of the United States Environmental Protection Agency, Denver seek funding in its Fiscal Year 2006 and 2007 budgets for air and water monitoring equipment to be placed at sites through Montezuma County. We ask that funding be directed to an entity in southwestern Colorado mutually agreeable to the Montezuma County Commissioners, the EPA, and other parties as they shall deem appropriate to query.

MOVED, SECONDED AND ADOPTED THIS 14th DAY OF JUNE 2005.

Orly Lucero, Mayor

ATTEST:

Linda L. Smith, City Clerk

City of Cortez
Resolution No. 14, Series 2005
USGS Colorado Water Science

Whereas, the City Council of the City of Cortez, Montezuma County, Colorado is interested in a healthy environment and clean air for citizens of the City, and

Whereas, concerns are being raised by City residents about the possible effects on the City environment and air quality by the proposed Desert Rock Energy Project to be built on Navajo Nation lands in the State of New Mexico, and

Whereas, Sithe Global Power, Inc. of Houston Texas and the Dine Power Authority have begun planning for two 750 MW coal-fired electric generating units and associated facilities for the proposed plant, and

Whereas, the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution, such as that emitted from the San Juan and Four Corners electric generation plants in New Mexico, greatly exceeds that emitted from all sources in the County, and

Whereas, mercury is a known pollutant emitted from coal-fired electric power generating plants and recent studies have shown that mercury can cause neurological damage and is especially harmful to developing fetuses and children, and

Whereas, the second highest concentrations of mercury in rain and snow recorded for any location in the western United States for the past two years have been found in Mesa Verde National Park, and

Whereas, State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury, and

Whereas, City residents with respiratory problems such as asthma are experiencing additional health problems on days when air pollution appears to be higher, and

Whereas, Mesa Verde National Park is the only known site for air quality data collection in Montezuma County and may not adequately provide a basis for characterizing air for the remainder of the County, including the City of Cortez, and

Whereas, additional water monitoring sites on a bi-weekly to monthly frequency are needed on the Dolores River and Mancos River systems in the County to measure levels of mercury in order to assess the ultimate fate of mercury from the proposed power plant and existing power plants.

Now Therefore Be It Resolved by the Cortez City Council,

That, the Council finds that additional water monitoring sites for mercury are needed on the Dolores and Mancos River systems to adequately assess the ultimate fate of mercury from air pollution sources outside the State of Colorado on the health of City residents, and

Further that, the Council requests that the USGS Colorado Water Science Director in Denver seek funding in the Fiscal Year 2006-2007 budgets for increasing the USGS Colorado ability to monitor mercury in water in the Dolores and Mancos River systems.

MOVED, SECONDED AND ADOPTED THIS 14th DAY OF JUNE 2005.

Orly Lucero, Mayor

ATTEST:

Linda L. Smith, City Clerk

RESOLUTION # 230
TOWN OF DOLORES
SUPPORT FOR AIR AND WATER MONITORING FUNDING THROUGH
COLORADO BUREAU OF LAND MANAGEMENT

WHEREAS, The Town of Dolores Board of Trustees, Montezuma County, Colorado is interested in a healthy environment and clean air for citizens of the Town; and

WHEREAS, concerns are being raised by Town residents about the possible effects on the Town environment and air quality by the proposed Desert Rock Energy Project to be built on Navajo Nation lands in the State of New Mexico; and

WHEREAS, Sithe Global Power, Inc. of Houston, Texas and the Dine' Power Authority have begun planning for two 750 MW coal-fired electric generating units and associated facilities for the proposed plant; and

WHEREAS, the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution, such as that emitted from the San Juan and Four Corners electric generation plants in New Mexico, greatly exceeds that emitted from all sources in the County; and

WHEREAS, mercury is a known pollutant emitted from coal-fired electric power generating plants and recent studies have shown that mercury can cause neurological damage and is especially harmful to developing fetuses and children; and

WHEREAS, the second highest concentrations of mercury in rain and snow recorded for any location in the western United States for the past two years have been found in Mesa Verde National Park; and

WHEREAS, State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury; and

WHEREAS, County residents with respiratory problems such as asthma are experiencing additional health problems on days when air pollution appears to be higher; and

WHEREAS, Mesa Verde National Park is the only known site for air quality data collection in Montezuma County and may not adequately provide a basis for characterizing air for the remainder of the County, including the Town of Dolores; and

WHEREAS, additional monitoring sites are needed in the County to measure current levels of ozone, mercury in rain and snow, and Dolores and Mancos River mercury concentrations in order to assess the additional impact on air quality of the proposed power plant, and

NOW, THEREFORE BE IT RESOLVED, that the Town Board, Town of Dolores finds that additional air and water monitoring sites are needed elsewhere in Montezuma County to adequately assess the impact of air pollution from sources outside the State of Colorado on the health of Town residents; and

BE IT FURTHER RESOLVED, that the Town Board, Town of Dolores requests that the Colorado Bureau of Land Management see funding in its Fiscal Year 2006 and 2007 budgets for air and water monitoring equipment to be placed at sites throughout Montezuma County. The Town Board asks that funding be directed to an entity in southwestern Colorado mutually agreeable to the Dolores Town Board, the Colorado Bureau of Land Management, and other parties as they shall deem appropriate to query.

Done this 12th day of September, 2005

Marianne Mate, Mayor
Town Board of Trustees

ATTEST:

Ronda Lancaster,
Town Clerk/Administrator

RESOLUTION NO. 2006–40

A RESOLUTION OF THE BOARD OF COUNTY COMMISSIONERS OF LA PLATA COUNTY, COLORADO, FOR REGION IX AIR DIVISION OF THE ENVIRONMENTAL PROTECTION AGENCY CONCERNING THE CLEAN AIR ACT PERMIT FOR THE DESERT ROCK POWER PLANT

WHEREAS, the United States Environmental Protection Agency (US EPA) Region IX has proposed a Clean Air Act permit that would authorize construction of a 1500-megawatt coal-fired power plant on the Navajo Nation; and

WHEREAS, the permit regulates the reduction of particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide, volatile organic compounds, and lead emissions with the Best Available Control Technology, and must comply with health-based National Ambient Air Quality Standards; and

WHEREAS, Chapter 6, page 6.1 of the La Plata County Comprehensive Plan - Environmental Resources states "La Plata County's natural resources are a valuable community asset. Ensuring their preservation and appropriate use is important to both the natural beauty and economy of La Plata County;" and

WHEREAS, "Environmental Quality and unique natural features are what defines the character of La Plata County and ensuring their continued viability and health is important;" and

WHEREAS, the comment period for this clean air quality permit closes before the draft Environmental Impact Statement is released to the public resulting in an incomplete understanding of the cumulative impacts of the plant; and

WHEREAS, mercury is a significant and demonstrable problem resulting in a degradation in the quality of life for La Plata County citizens, failure to include the monitoring of mercury, a byproduct of all coal burning power plants would be negligent to the citizens;

NOW THEREFORE, BE IT RESOLVED BY THE BOARD OF COUNTY COMMISSIONERS OF LA PLATA COUNTY, COLORADO, AS FOLLOWS:

1. That the La Plata County Board of County Commissioners hereby requests that the Environmental Protection Agency Region IX Air Division deny the Clean Air Act Permit for Desert Rock Power Plant so the full Environmental Impact Statement for this project is completed to allow the citizens of La Plata County an understanding of the full cumulative impacts from the proposed plant.

2. That the La Plata County Board of County Commissioners hereby requests that all available technology be utilized to reduce the amount of pollutants, including mercury, emitted by this plant.

DONE AND ADOPTED IN DURANGO, LA PLATA COUNTY, COLORADO,
this 24th day of October, 2006.

BOARD OF COUNTY COMMISSIONERS
LA PLATA COUNTY, COLORADO

ATTEST

Wallace "Wally" White, Chair

Clerk to the Board

Robert A. Lieb, Vice Chair

Sheryl D. Ayers, Commissioner

DISTRIBUTION: United States Environmental Protection Agency Region IX
Attn: Robert Baker
75 Hawthorne Street
San Francisco, CA 94105
desertrockairpermit@epa.gov

Resolution (BLM-NM)

Whereas the Board of Trustees, Town of Mancos, Montezuma County, Colorado is interested in a healthy environment and clean air for citizens of the Town, and

Whereas concerns are being raised by Town residents about the possible effects on the Town environment and air quality by the proposed Desert Rock Energy Project to be built on Navajo Nation lands in the State of New Mexico, and

Whereas Sithe Global Power, Inc. of Houston Texas and the Dine Power Authority have begun planning for two 750 MW coal-fired electric generating units and associated facilities for the proposed plant, and

Whereas the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution, such as that emitted from the San Juan and Four Corners electric generation plants in New Mexico, greatly exceeds that emitted from all sources in the County, and

Whereas mercury is a known pollutant emitted from coal-fired electric power generating plants and recent studies have shown that mercury can cause neurological damage and is especially harmful to developing fetuses and children, and

Whereas the second highest concentrations of mercury in rain and snow recorded for any location in the western United States for the past two years have been found in Mesa Verde National Park, and

Whereas State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury, and

Whereas County residents with respiratory problems such as asthma are experiencing additional health problems on days when air pollution appears to be higher, and

Whereas Mesa Verde National Park is the only known site for air quality data collection in Montezuma County and may not adequately provide a basis for characterizing air for the remainder of the County, including the Town of Mancos, and

Whereas additional monitoring sites are needed in the County to measure current levels of ozone, mercury in rain and snow, and Dolores and Mancos River mercury concentrations in order to assess the additional impact on air quality of the proposed power plant, Now Therefore

Be It Resolved, that the Board of Trustees, Town of Mancos finds that additional air and water monitoring sites are needed elsewhere in Montezuma County to adequately assess the impact of air pollution from sources outside the State of Colorado on the health of Town residents, and

Be It Further Resolved, that the Board of Trustees, Town of Mancos requests that the Bureau of Land Management New Mexico State Director, Santa Fe seek funding in the Fiscal Year 2006-2007 budgets for air quality monitoring equipment for ozone to be placed at appropriate sites in Montezuma County. We ask that funding be directed to an entity in southwestern Colorado mutually agreeable to the Board of Trustees, the BLM New Mexico and Colorado State Directors, and to other parties as they shall deem appropriate.

APPROVED THIS 22 DAY of June, 2005

Greg Rath
Greg Rath, Mayor

Michele Black
Michele Black, Mayor Pro-Tem

Perry Lewis

Herman J. Muniz
Herman Muniz

Nick Baumgartner
Nick Baumgartner

Ray Martinez
Ray Martinez

Nicki Elmore
Nicki Elmore

THE BOARD OF COUNTY COMMISSIONERS
OF THE COUNTY OF MONTEZUMA
STATE OF COLORADO

At a regular meeting of the Board of County Commissioners of Montezuma County, Colorado, duly convened and held the 13th day of June, 2005, with the following persons in attendance:

Commissioners:	Dewayne Findley, Gerald Koppenhafer, and Larrie Rule
Commissioners Absent:	
County Administrator:	Thomas J. Weaver
County Attorney:	Bob Slough
Clerk and Recorder:	Carol Tullis

the following proceedings, among others, were taken:

Resolution # 5-2005

Resolution (EPA)

WHEREAS, the Commissioners of Montezuma County Colorado are interested in a healthy environment, clean air and water for citizens of Montezuma County; and

WHEREAS, concerns are being raised by Montezuma County residents about the possible effects on air quality and water by the proposed Desert Rock Energy Project; and

WHEREAS, the Colorado Department of Health and Environment's most recent Montezuma County Emission Inventory indicates imported air pollution; and

WHEREAS, mercury is a known pollutant emitted from coal-fired electric power generating plants; and

WHEREAS, State Game and Fish officials have warned the public about eating fish in McPhee and Narraguinnep Reservoirs because the fish contain high levels of mercury; and

WHEREAS, Mesa Verde National Park is the only known site for air quality data collection in Montezuma County; and

WHEREAS, additional monitoring sites may be needed in the County to measure current levels of ozone, and mercury in order to assess the additional impact of the proposed power plant; and

WHEREAS, the Commissioners of Montezuma County find that additional air and water monitoring sites may be needed elsewhere in the County to adequately assess the impact of air pollution and water contamination,

NOW THEREFORE BE IT RESOLVED THAT the Commissioners request that the Regional Administrator of the United States Environmental Protection Agency, Denver seek funding for equipment, operation and data analysis in its Fiscal Year 2006 and 2007 budgets for air and water monitoring equipment, as Montezuma County assumes no responsibility for the purchase, operation and data analysis of any equipment associated with this resolution, to be placed at sites throughout Montezuma County.

Commissioners voting aye in favor of the resolution were:

H Dewayne Findley   Gerald Koppenhafer   Larrie D Rule

Commissioners voting nay against the resolution were:

________________   ________________   ________________

Carol Tullis
County Clerk and Recorder
Montezuma County, Colorado

I certify that the above Resolution is a true and correct copy of same as it appears in the minutes of the Board of County Commissioners of Montezuma County, Colorado and the votes upon same are true and correct.

Dated this 13th day of June, 2005.

MONTEZUMA COUNTY SEAL 1889 COLORADO

Carol Tullis
County Clerk and Recorder
Montezuma County, Colorado

BUDGETS / FUNDING AND PROJECTED COSTS

Once the task of identifying suitable monitoring site locations has been completed, funding must be obtained to set up and operate the sites.

Capital costs and operating costs of a monitoring site will vary according to what parameters the site is measuring. The following spreadsheets show examples of capital and operating costs of two different monitoring sites.

The Shamrock site is under the jurisdiction of the IMPROVE **(Interagency Monitoring of Protected Visual Environments)** federal program and the Deming site is a state-run SLAMS **(State/Local Air Monitoring Stations)** site.

Funding of these types of sites usually comes from the federal government, but as federal budgets are cut, other resources have to be sought out. States have entered into partnerships with industry in order to fund monitoring activities. Various permit fees can be instituted or increased to obtain funds for monitoring. Private organizations can also be possible sources of funding.

A spreadsheet of possible funding sources is also shown. This spreadsheet lists organizations that are potential sources of funding, the geographic areas supported, applicant requirements, and the highest recent grants awarded. Most of these private funders require that grant recipients be non-profit, 501 (c) (3) organizations. Many of the funders also like projects that are collaborations and creative efforts capable of replication in other areas. They might support joint non-profit/governmental projects.

Shamrock Monitoring Site Capital Costs

Description	Qty	Unit Price	Total Price	NOTES
NOX Analyzer	1	10,000.00	10,000.00	
O3 Analyzer	1	0.00	0.00	From other site
NOx Calibration Devices	1	8,000.00	8,000.00	
IMPROVE Aerosol 4 Modules	1	16,000.00	16,000.00	
IMPROVE Housing Installation	1	5,000.00	5,000.00	
Climate Controlled Monitoring Shelter	1	9,000.00	9,000.00	
Data Logger	1	5,000.00	5,000.00	
Installation for Data Logger	1	5,000.00	5,000.00	
Laptop Computer	1	2,500.00	2,500.00	
Meteorology Station	1	4,000.00	4,000.00	
TOTAL			**$64,500.00**	

Shamrock Monitoring Site Annual Operating Costs

Description	Qty	Unit Price	Total Price	NOTES
Power and Phone	1	1,000.00	1,000.00	
Data Handling Contract	1	25,000.00	25,000.00	Data handling, digital photography, calibration, and reporting for NOx, Ozone, and Meteorology
IMPROVE Contract Fees	1	33,000.00	33,000.00	Analysis, reporting, and QA/QC
Labor	1	4,000.00	4,000.00	Total annual labor for: Weekly calibration, maintenance, and data downloads
TOTAL			**$63,000.00**	

Deming Monitoring Site Capital Costs

Description	Qty	Unit Price	Total Price
Thermo 42i NOX Analyzer	1	6,464.68	6,464.68
Thermo 49i O3 Analyzer	1	4,422.88	4,422.88
R&P TEOM PM10 Analyzer	1	17,500.00	17,500.00
Monitoring Shelter; Morgan Bldg	1	6,000.00	6,000.00
Intake Manifold	1	1,356.00	1,356.00
Sabio Calibrator	1	10,975.00	10,975.00
Sabio Keyboard	1	50.00	50.00
Sabio Zero Air Supply	1	2,447.00	2,447.00
Serial Cable; Sabio to Sabio	1	15.00	15.00
Null Modem Cable; Sabio to Computer	1	15.00	15.00
Solenoid Valves	2	215.00	430.00
Solenoid Valve Driver Cable	1	40.00	40.00
SS "T"'s (1/8" NPT to 1/4" OD)	2	17.60	35.20
SS Elbows (1/8" NPT to 1/4" OD)	4	15.00	60.00
Solenoid Valve Mounting Bracket	1	50.00	50.00
1/4" Teflon Tubing (50 ft)	0.2	350.00	70.00
1/8" Teflon Tubing (50 ft)	0.2	450.00	90.00
1/4" SS Plugs (caps)	4	7.50	30.00
1/8" SS Plugs (caps)	4	5.50	22.00
Glass Funnels	2	15.00	30.00
Surgical Tubing (50 ft)	0.2	40.00	8.00
EPA NO Protocol Gas Standard	1	258.00	258.00
Gas Regulator	1	625.00	625.00
Gas Cylinder Wall Mounting Bracket	1	25.00	25.00
Serial Cables; asst'd lengths, Air Monitors to Computer Moxa Cable	3	15.00	45.00
8-Port Moxa Card	1	300.00	300.00
Moxa Cable; 8 strand	1	55.00	55.00
Campbell Data Logger (CR10x)	1	1,779.00	1,779.00
12v Battery for Data Logger	1	25.00	25.00
Power Adapter for Data Logger	1	10.00	10.00
SC32B Optically Isolated Interface	1	80.00	80.00
APC UPS	1	200.00	200.00

Description	Qty	Unit Price	Total Price
Wireless Modem	1	500.00	500.00
Computer, monitor, keyboard, mouse	1	3,000.00	3,000.00
MET Tower Base; B-14	1	75.00	75.00
MET Tower	1	511.00	511.00
Lightning Rod	1	15.00	15.00
Grounding Rod	1	25.00	25.00
Rod Clamps	2	15.00	30.00
Tower Mast	1	35.00	35.00
Tower Cross Bar	1	35.00	35.00
Hardware Crosses, standard and offset	1	15.00	15.00
Solar Sensor (Li 200 SA 50)w/ Cable	1	215.00	215.00
Solar Sensor Mv Adapter (2220)	1	27.00	27.00
Solar Sensor Mounting Base	1	44.00	44.00
Solar Sensor Mounting Arm	1	65.00	65.00
Wind Monitor Unit (05305-5 AQ)	1	1,200.00	1,200.00
Wind Monitor Cable (50 ft)	1	50.00	50.00
Temperature Probes w/ Cable	2	425.00	850.00
Temperature Probe Aspirator	2	726.00	1,452.00
Power Installation	1	1,500.00	1,500.00
Security Fencing	1	1,600.00	1,600.00
TOTAL			**$ 64,756.76**

Deming Monitoring Site Annual Operating Costs

Description	Qty	Unit Price	Total Price
Power:	1	845.00	845.00
Communications:	1	830.00	830.00
Labor:	1	5,285.00	5,285.00
Consumables:	1	1,500.00	1,500.00
TOTAL			**$ 8,460.00**

Possible Funding Sources for Monitoring

Name & contact info	Areas Funded	Applicant requirements	Highest Recent Grant
PRIVATE SOURCES			
Ben & Jerry's Foundation (802) 846-1500 www.benjerry.com/foundation	national	501(c)(3)	$15,000
Patagonia, Inc. (805)643-8616 www.patagoniainc.com	Colorado	501(c)(3)	$20,000
Coutts & Clark Western Foundation (970) 259-6169 thinair@starband.net	SW CO multi-state	501(c)(3)	$5,000
William & Flora Hewlett Foundation (650) 234-4500 www.hewlett.org	national	501(c)(3)	$2,400,000
Microsoft Corp. Rocky Mountain Region (720) 528-1700 sandyp@microsoft.com	Rocky Mountain area	501(c)(3) local govt. entity?	$30,000
Anschutz Family Foundation (303) 293-2338 info@anschutzfamilyfoundation.org	Colorado, especially rural	501(c)(3)	$20,000
Eastman Kodak Charitable Trust (585)724-2434 www.kodak.com/us/en/corp/community.shtml	Colorado	501(c)(3)	$250,000

Name & contact info	Areas Funded	Applicant requirements	Highest Recent Grant
Greenlee Family Foundation (303) 444-0206 directorgff@aol.com	SW CO	501(c)(3)	$10,000
El Pomar Foundation 800-554-7711 grants@elpomar.org	Colorado	501(c)(3)	$1,550,000
Ford Motor Company Fund (313) 845-8711 fordfund@ford.com	National	501(c)(3)	$265,000

ADDITIONAL SOURCES FOR INFORMATION ON PRIVATE FUNDING FOR ENVIRONMENTAL PROJECTS

Environmental Grant Makers Association
(212 812-4260
shansen@ega.org

Community Resource Center, Inc.
(303) 623-1540
www.cramerica.org

SUMMARY OF SUGGESTIONS / PRIORITIES

Introduction

Air pollution is defined as a chemical, physical or biological agent that modifies the natural characteristics of the atmosphere.[1] Pollutants in the air may be natural in origin, such as blowing dust, forest fire smoke or organic compounds from vegetation. Of greater concern are anthropogenic, or man-made pollutants. These include chemicals and particulates from motor vehicles, smoke stacks, incinerators, refineries, industrial degreasing and pesticides, to name just a few. Pollutants may be classified as primary, where they are directly released form a source, or as secondary, where they are formed from reactions of other pollutants in the atmosphere. The health effects caused by air pollutants may range from subtle biochemical and physiological changes to difficulty breathing, wheezing, coughing and aggravation of existing respiratory and cardiac conditions. These effects can result in increased medication use, increased doctor or emergency room visits, more hospital admissions and premature death.[1]

Air pollution has been an issue to human health for centuries. One of the most famous episodes was the "Great Smog" that occurred in London, England in December 1952. Lasting for four days, over 12,000 people died either during the episode or in the months following as a result of the health effects.[2] While not the first air pollution smog to cause deaths, it was the largest to date and led to some of the first Clean Air Acts and air quality regulations in the world. In the United States, the first Clean Air Act was passed in 1963. However, it was not until the Clean Air Act of 1970 and with the creation of the U.S. Environmental Protection Agency (EPA) in the same year that real air pollution control came into full force.[3] This 1970 Clean Air Act was revised and expanded in 1990.

The U.S. EPA has set national ambient air quality standards (NAAQS) for six "criteria" pollutants. These are wide-spread pollutants from numerous and diverse sources that are considered harmful to public health and the environment. There are two types of NAAQS. Primary standards set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation, and buildings.[4] The "criteria" pollutants are carbon monoxide, ozone, sulfur dioxide, nitrogen dioxide, lead and particulates (PM_{10} and $PM_{2.5}$). However, there are many other pollutants that can be found in the ambient air. Air toxics, which includes a variety of organic compounds and metals, is an area of increasing concern to human health. Visibility, while not directly a health-related concern, is an aesthetic concern and can be an indicator of other health-related pollutants. The sources and health/environmental impacts vary from pollutant to pollutant, though many are linked to each other.

Carbon monoxide is a colorless and odorless gas formed primarily from incomplete combustion of fuels. It is a product of motor vehicle exhaust, which contributes about 60 percent of all carbon monoxide emissions nationwide. Other sources of carbon monoxide emissions include industrial processes, non-transportation fuel combustion, and natural sources such as wildfires. With increasing emissions controls on motor vehicles and other sources, ambient carbon monoxide levels nationwide have been reduced significantly over the past two decades. Carbon monoxide enters the bloodstream through the lungs and reduces oxygen delivery to the body's organs and tissues. The health threat from carbon monoxide is most serious for those who suffer from cardiovascular disease. Visual impairment, reduced work capacity, reduced manual dexterity, poor learning ability, and difficulty in performing complex tasks are all associated with exposure to elevated carbon monoxide levels.[5]

Ozone is a highly reactive gas that is a form of oxygen. Though it occurs naturally in the stratosphere to provide a protective layer high above the earth, at ground-level it is the prime ingredient of smog.[6] Ozone is a secondary pollutant formed by the action of sunlight on carbon-based chemicals known as hydrocarbons, acting in combination with a group of air pollutants called oxides of nitrogen. As a result, ozone is generally a summer afternoon issue. Ozone reacts chemically with internal body tissues that it comes in contact with, such as those in the lung. It also reacts with other materials such as rubber compounds, breaking them down. Health symptoms include shortness of breath, chest pain when inhaling deeply, wheezing and coughing. Research on the effects of prolonged exposures to relatively low levels of ozone have found reductions in lung function, biological evidence of inflammation of the lung lining and respiratory discomfort.[7]

Sulfur dioxide is a gas that is formed when fuel containing sulfur (mainly coal and oil) is burned, and during metal smelting and other industrial processes. The major health concerns associated with exposure to high concentrations of sulfur dioxide include effects on breathing, respiratory illness, alterations in the lungs defenses, and aggravation of existing cardiovascular disease. Asthmatics and individuals with cardiovascular disease or chronic lung disease, as well as children and the elderly are particularly susceptible. In addition, sulfur dioxide is a major precursor to $PM_{2.5}$ particulates and acid rain.[8]

Nitrogen dioxide is a light brown gas that can become an important component of urban haze. Oxides of nitrogen (which includes nitrogen dioxide) usually enter the air as the result of high-temperature combustion processes, such as those occurring in automobiles and power plants. Nitrogen dioxide plays an important role in the atmospheric reactions that generate ozone. Home heaters and gas stoves also produce substantial amounts of nitrogen dioxide. Nitrogen dioxide can irritate the lungs and lower resistance to respiratory infections. Oxides of nitrogen are an important precursor to ozone, $PM_{2.5}$ particulates and acid rain.[9]

Lead is a metal that is used in a wide variety of commercial products. In the past, automotive sources were the major contributor of lead emissions to the atmosphere. As a result of unleaded fuels now being used, ambient lead levels have decreased significantly. Today, metals processing is the major source of lead emissions to the atmosphere. The highest concentrations of lead are found in the vicinity of nonferrous and ferrous smelters, battery manufacturers, and other stationary sources of lead emissions. Exposure to lead occurs mainly through the inhalation of air and the ingestion of lead in food, water, soil, or dust. It accumulates in the blood, bones, and soft tissues. Because it is not readily excreted, lead can also adversely affect the kidneys, liver, nervous system, and other organs. Excessive exposure to lead may cause neurological impairments such as seizures, mental retardation, and/or behavioral disorders. Recent studies also show that lead may be a factor in high blood pressure and subsequent heart disease.[10]

Particle pollution is a mixture of microscopic solids and liquid droplets suspended in the air. This pollution, also known as particulate matter, is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, soil or dust particles, and allergens (such as fragments of pollen or mold spores).[11] Particulate pollution comes from such diverse sources as factory and utility smokestacks, vehicle exhaust, wood burning, mining, construction activity, and agriculture.[12] The size of particles is directly linked to their potential for causing health problems. Small particles less than 10 micrometers in diameter pose the greatest problems, because they can get deep into your lungs, and some may even get into your bloodstream. Exposure to such particles can affect both your lungs and your heart. Particulate matter air pollution is especially harmful to people with lung disease such as asthma and chronic obstructive pulmonary disease (COPD), which includes chronic bronchitis and emphysema. Exposure to particulate air pollution can trigger asthma attacks and cause wheezing, coughing, and respiratory irritation in individuals with sensitive airways. Larger particles are of less concern, although they can irritate your eyes, nose, and throat.

Toxic air pollutants, also known as hazardous air pollutants, are those pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental effects. Examples of toxic air pollutants include benzene, which is found in gasoline; perchlorethlyene, which is emitted from some dry cleaning facilities; and methylene chloride, which is used as a solvent and paint stripper by a number of industries. Examples of other listed air toxics include dioxin, asbestos, toluene, and metals such as cadmium, mercury, chromium, and lead compounds.[13] There are no NAAQS for toxic air pollutants. Instead, they are regulated nationally by requiring the use of pollution controls on sources.

Visibility is defined as the greatest distance at which a black object can be seen and recognized when observed against a background fog or sky. From an aesthetic perspective, visibility represents not just visual range, but rather the overall visual experience of a scene.[14] Thus, visibility issues are not directly a health impact. However, many of the pollutants that cause visibility degradation may cause health impacts. In addition to primary particulates, secondary particulates are a part of visibility degradation. These secondary particulates can be formed from sulfur dioxide and nitrogen dioxide, both of which are criteria pollutants.

Both N and sulfur (S) oxides can form “acid rain” and lead to acidification of surface and groundwater and soils. S oxides primarily are emitted to the atmosphere by burning of fossil fuels.

Increased deposition of atmospheric N can result in high levels of nitrate in surface and ground water, shifts in species, decreased plant health, and eutrophication (i.e., fertilization) of otherwise naturally low-productivity ecosystems.

Analysis and Interpretation of Existing Data

Meteorology

Meteorological data are collected at a number of different locations in the Four Corners region.

In looking at the annual wind roses, it is evident that some sites are more influenced by local topography than others. An example is the Cortez CoAgMet site, which is located in the valley between Sleeping Ute Mountain and Mesa Verde and is subjected to definite channeling effects. Another example is the U.S. Forest Service Shamrock site, which is located on the side of a hogback ridge. It can also be seen that the strongest winds are generally from a more westerly direction than an easterly one. From the daytime wind roses, there are general westerly or northerly/southerly components to the winds. In comparison, the nighttime wind roses show more of general easterly to northerly components. These trends are expected based on prevailing regional wind patterns as well as more local convection heating and cooling patterns along with topography.

These wind roses can be broken down even further, such as only for summer afternoon periods when ozone levels are expected to be highest (see summer afternoon wind rose maps). These wind roses show, in general, a predominant westerly to southwesterly component. As mentioned previously, some sites still exhibit wind patterns that are strongly influenced by local topography rather than more regional winds. However, these types of plots are useful in describing what may happen with air pollution flows during different periods of time. While not performed for this analysis, additional seasonal plots could be dome, such as for winter when inversions are more prevalent.

Ozone and Precursor Gases

Ground level ozone is currently monitored on a continuous basis at nine locations in the Four Corners region, with seven sites being in a core area. For regulatory comparisons to the NAAQS, continuous analyzers that have been designated as “equivalent’ or “reference” by the U.S. Environmental Protection Agency (EPA) are used.

Currently, ambient ozone levels in the Four Corners region are below the level of the current NAAQS (see trends and standards graphs). However, at Mesa Verde and one Southern Ute site there is an increasing trend, and the two newer sites (USFS, Navajo Lake) are recording higher levels. Many of the sites would be above the level of a reduced NAAQS, as proposed by CASAC.

With ozone typically having peak concentrations in the summer afternoons when sunlight is strongest, pollutant roses were developed accordingly and were placed on both political boundary and topographic base maps (see pollutant rose maps). As can be seen from these pollutant rose maps, ozone at the three southern core area sites in New Mexico and the Mesa Verde site in Colorado show predominantly westerly wind directions in this summer afternoon timeframe. This generally mirrors the predominant San Juan River drainage. The two Southern Ute Tribe sites and the Forest Service Shamrock site appear to be heavily influenced by local topography. Thus, based on these pollutant roses, it is likely that ozone concentrations could also be high further to the east and north of the New Mexico Navajo Lake site, further up the San Juan River and Piedra River drainages. While no monitoring exists to confirm or deny, winds could also flow up other drainages in summer afternoons, including the Dolores and Animas Rivers.

For ozone precursor gases, NOx monitoring currently exists at six sites in the Four Corners region. NO_2 levels have been fairly steady over the years at most sites, at a level well below the NAAQS. At two sites in particular, San Juan Substation, NM and Bloomfield, NM, the NO_2 levels do appear to be increasing over time.

NO, unfortunately, has not been reported consistently as it is not designated a criteria pollutant. However, NO levels do appear to be increasing at both Southern Ute Tribe sites, Ignacio and Bondad. These increases in NO and NO_2 are of concern due to the potential for increased ozone formation and also indicates that there are increased combustion sources in the area, possibly due to oil and gas development and increased traffic.

VOC baseline monitoring for San Juan County, New Mexico was conducted in 2004 and 2005 at three sites. One site was near Bloomfield, NM near some industrial sources, a second near the San Juan power plant and the third site was near Navajo Lake, in an oil and gas development area. Results showed that alkane concentrations dominated, especially ethane and propane. The biogenic compound isoprene and the highly reactive VOC compounds, ethylene and propylene, were not present in significant quantities.

Mercury

Total mercury in wet deposition has been monitored at Mesa Verde National Park since 2002 as part of the Mercury Deposition Network. Results show mercury concentrations among the highest in the nation during certain years. Precipitation is relatively low, however, so mercury in wet deposition is moderate. Mercury concentrations have been measured in snowpack at a few sites in the San Juan Mountains by the USGS and moderate concentrations similar to the Colorado Front Range have been recorded. Mercury concentrations in sport fish from several reservoirs have exceeded the 0.5 microg/g action level resulting in mercury fish consumption advisories for water bodies including McPhee, Narraguinnep, Todden, Navajo, Sanchez and Vallecito Reservoirs and segments of the San Juan River. Atmospheric deposition just to the surface of McPhee and Narraguinnep Reservoirs (i.e., not including air deposition to the rest of the watershed) is estimated to contribute 8.2% and 47.1% of total mercury load to these water bodies, respectively.

Nitrogen and Sulfur Compounds

Currently, monitoring stations for N, S, and H+ in wet deposition exist at Mesa Verde National Park (since 1981), Molas Pass (since 1986), and Wolf Creek Pass (since 1992) as part of the National Atmospheric Deposition Program. Dry deposition of N and S, which is especially important in arid regions (Fenn et al. 2003), has been monitored since 1995 at Mesa Verde NP as part of the Clean Air Status and Trends Network.

Trends of sulfate concentrations in wet deposition show either a decrease over time or no change at monitoring stations in the vicinity of the Four Corners region. Conversely, trends of nitrate and ammonium concentrations in wet deposition appear to be stable or increasing. In general, N in wet deposition in the Four Corners and San Juan Mountain region currently is at or above the 1.5 kg/ha/yr ecological critical load discussed above for Rocky Mountain National Park. Dry deposition data from Mesa Verde NP indicate that, for the period 1997-2000, dry deposition contributed about half of the total inorganic nitrogen deposition and about one-third of the total sulfur deposition. The short data record is insufficient to detect trends over time for dry deposition. Model simulations of total wet plus dry deposition of N in the western United States indicate a possible hotspot for N deposition in SW Colorado.

Visibility

Currently, there are four sites within the Four Corners region that monitor visibility: Mesa Verde National Park, the Weminuche Wilderness (near Purgatory,) the Shamrock Mine (southeast La Plata County,) and Canyonlands National Park. Of these four sites, only the Forest Service monitoring station at the Shamrock Mine records images, and is included in IMPROVE's optical and scene monitoring network. Additionally, because the Canyonlands site lies on the margin of the Four Corners Region, and it is also located at a comparatively lower elevation north of the Blue Mountains, it may not serve as the best indicator of visibility trends in the Four Corners proper.

Preliminary analysis of deciview trends at Mesa Verde, and also of visibility-impairing gasses and particulates as monitored at other sites, does not reveal a clear trend of how visibility might be changing in the Four Corners. This appraisal is not concomitant with the observations of many area residents. It may be indicative of monitoring gaps that exist in the Four Corners, and it has led to the perception by members of the Task Force Monitoring Group that a comprehensive, detailed analysis of all available data regarding visibility is greatly needed.

Despite that ambiguity, however, there are a few details worth noting. In September of 2005, the Interim Emissions Workgroup of the Four Corners Air Quality Task Force recommended that an ambient monitoring program for gaseous ammonia be initiated in the Four Corners region. The purpose of this program is to set a current baseline of ambient gaseous ammonia concentrations in the Four Corners, that can be compared to monitored values in approximately 3-5 years after the implementation of NOx controls (e.g. NSCR) on oil and gas equipment. The use of NSCR may increase ammonia emissions in the area, but these emissions have not been quantified and may or may not significantly affect visibility. Ammonia at high enough concentrations can contribute to worsening visibility by forming PM 2.5 ammonium nitrates and ammonium sulfates.

Additionally, the implementation of new SO_2 controls at the San Juan Generating Station in 1999 has successfully reduced SO_2 emissions in the area. Because of the high impact that SO_2 can have upon visibility, that reduction has likely made a positive impact upon visibility conditions in the Four Corners. However, changes in monitoring conditions at San Juan Substation have not been limited to a decrease in SO_2. Concurrently, it appears that NOx concentrations have risen, and now dominate over SO_2.

Carbon Monoxide, PM_{10} and Other Common Pollutants

Carbon Monoxide

Carbon monoxide in the ambient air is currently monitored on a continuous basis at only one site in the Four Corners region. This is at the Southern Ute Tribe's Ignacio site in southern Colorado. Monitoring was performed at New Mexico's Farmington site, but was discontinued in 2000. Ambient carbon monoxide levels in the Four Corners region are well below the level of the current NAAQS.

PM_{10}

PM_{10} in the ambient air is, historically, the most heavily monitored pollutant in the Four Corners region. Most of the monitoring has been performed using filter-based "high-volume" samplers that collect 24-hour samples and most of the data are available on EPA's Air Quality System. Ambient PM_{10} levels in the Four Corners region are well below the level of the current and former NAAQS.

Others

No monitoring for lead exists in the Four Corners region. Due to the introduction of unleaded gasoline in the 1970's, ambient lead levels have decreased to levels that are near instrument detection levels. Likewise, no monitoring exists for other pollutants such as carbon dioxide, HAPs or pesticides.

<u>Suggestions for Future Monitoring Work</u>

Meteorology

No significant data gaps exist for meteorological monitoring in the Four Corners region, with the exception of southwestern Utah and northeastern Arizona. No suggestions for additional monitoring of meteorological parameters are currently being proposed.

Ozone and Precursor Gases

While it would appear that there is a sufficient ozone monitoring network in the Four Corners region, some areas are lacking. Pollutant roses were developed to determine the directions from which ozone precursors are most likely to be transported by wind. Ozone monitoring currently exists in the major oil and gas development areas, but little downwind ozone monitoring currently exists.

VOCs are also a gap, as the short-term studies in 2004 and 2005 were located toward the southern edge of the oil and gas development area, or not in the development area at all. While emissions inventories can provide an estimate of total VOCs that may be released to the atmosphere, these are primarily based on predicted emissions, not on actual measurements. This is a concern as different VOCs have different ozone formation potentials and the oil and gas development has dramatically increased in the region since these studies.

<u>Suggestions for Future Monitoring Work for Ozone:</u>

Install and operate two or three long-term continuous monitoring stations for ozone. One station would be located upstream of Navajo Lake, in the San Juan River drainage toward Pagosa Springs, CO, or in the Piedra River drainage, toward Chimney Rock, CO. This area is toward the northeastern portion of the Four Corners region and is downwind of many VOC precursor gas sources from oil and gas development. The second station would be located to the north of Cortez. This area is in the north-central portion of the Four Corners region and is downwind of both an urban area and any precursor gas emissions that would funnel up between Sleeping Ute Mountain and Mesa Verde. If funding exists, a third site in Arizona on Navajo Nation land, in the southwest portion of the Four Corners area, is recommended. This site, possibly at Canyon de Chelly National Monument, would be to the west of a high ozone area as determined in the 2003 passive ozone study and would provide a good representation of regional ozone levels entering the Four Corners area. Each site, including shelter and instrumentation, would cost approximately $15,000 to $20,000 (total = $45,000 to $60,000). Annual operating costs (not including field personnel) would be approximately $1,500 per site (total = $3,000).

Perform an ozone saturation study using passive samplers across the entire Four Corners region to determine areas of highest ozone concentration. This would help determine if existing or new continuous monitoring sites are located in appropriate areas or if continuous ozone monitors need to be added or moved. It is expected that at least 20 passive ozone sites over the four-state region would be needed. Running for 30 days during a summer, the approximate cost would be $22,000 (not including field personnel time).

Perform monitoring for VOCs (in particular NMOCs) and carbonyls in the oil and gas development areas to determine the actual constituents in the emissions from wellheads, leaks and tanks. This would help in determining the potential for ozone formation from these compounds. This suggestion also includes follow-up monitoring for VOCs, both in and near the oil and gas development area, to compare to the 2004 and 2005 baseline data from San Juan County, New Mexico. A minimum of four to five sites is recommended; two sites in the oil and gas development area, one background site and one or two follow-up sites. For a year of monitoring, every sixth day, the approximate cost (not including field personnel time) would be $45,000 per site (total = $180,000 to $225,000).

Mercury

Very little data exists for the Four Corners Region with which to assess current risks and trends over time for mercury in air deposition, ecosystems, and sensitive human populations. No data exists for mercury in deposition at high elevations. Wet deposition of mercury at Mesa Verde National Park may not portray the situation in the mountains where mercury may be deposited at higher concentrations and total amounts because of greater rates of precipitation and the process of cold condensation, which causes volatile compounds to migrate towards colder areas at high elevation and latitude[7]. No information about total mercury deposition from the atmosphere (i.e., including dry deposition) exists for low or high elevations in the Four Corners Region. Furthermore, analysis of sources of air deposition of mercury is lacking. Except for a handful of reservoirs, no information exists for incorporation of mercury into aquatic ecosystems and subsequent effects on food-webs. No systematic effort exists to document mercury impacts in a wide range of water bodies over space and time. Lastly, impacts of mercury exposure to human populations are unknown.

<u>Suggestions for Future Monitoring Work for Mercury:</u>

1. Install and operate a long-term monitoring station for mercury in wet deposition for a location at high elevation where precipitation amounts are greater than the site at Mesa Verde NP. Co-location of the collector with the NADP site at Molas Pass would provide data pertinent to Weminuche Wilderness and the headwaters of Vallecito Reservoir. This monitor would be part of the Mercury Deposition Network (MDN). Upgrading the NADP monitoring equipment at Molas Pass to include the MDN specifications would cost $5,000 to $6,000, while annual monitoring costs are $12,112 plus personnel as of September 2006.

2. Install and operate a long-term monitoring station for mercury in total deposition (wet and dry) for at least one MDN station in the Four Corners Region. Speciated data will be collected and analyzed as is feasible. The MDN is currently developing this program and costs are anticipated at about $50,000 per year.

3. Support multi-year comprehensive mercury source apportionment study to investigate the impact of local and regional coal combustion sources on atmospheric mercury deposition. This type of study would require additional deposition monitoring (i.e., suggestions 1 & 2 above). Speciated data will be collected and analyzed as is feasible. A mercury monitoring and source apportionment study was recently completed for eastern Ohio. (http://pubs.acs.org/cgi-bin/asap.cgi/esthag/asap/html/es060377q.html9). Costs TBD.

4. Support a study of mercury incorporation and cycling in aquatic ecosystem food-webs, including total and methyl mercury in the food-webs of lakes and wetlands. This option includes studies that determine which ecosystems currently have high levels of total and methyl mercury in food-web components, how mercury levels in ecosystems change over time, where the mercury is coming from, and what conditions are causing the mercury to become methylated (the toxic form of mercury that bio-accumulates in food-webs). This information would allow tracking of mercury risks over time and space and serves as the basis for predicting future impacts. Existing reservoir studies and the upcoming MSI investigation serve as a starting point to build a collaborative and systematic approach. Costs TBD.

5. Support continued studies of mercury concentrations in sensitive human populations in the region to understand what exposure factors increase likelihood of unhealthy mercury levels in the body. Dr. Richard Grossman's study serves as a starting point to continue this effort. Costs TBD.

6. Form a multi-partner Mercury Advisory Committee that would work collaboratively to prioritize research and monitoring needs, develop funding mechanisms to sustain long-term mercury studies, and work to communicate study findings to decision-makers. The Committee would include technical experts and stakeholder representatives from States, local governments, land management agencies, watershed groups, the energy industry, etc.

Nitrogen and Sulfur Compounds

While data for N in wet deposition exist from multiple sites in the region, dry deposition is studied only at Mesa Verde National Park, which does not represent higher-elevations common near the Four corners region. Data concerning ecological effects of N deposition are very sparse for both high and low elevations and the limited data that do exist have not been analyzed adequately. No data exists for N and S deposition in the vicinity of emission sources. For example, no monitoring of N and S in wet or dry deposition occurs in NW New Mexico with the exception of Bandelier National Park.

Suggestions for Future Monitoring Work for Nitrogen and Sulfur Compounds:

Continue monitoring for N, S and H+ in wet deposition via the NADP at the Molas Pass, Wolfe Creek Pass and Mesa Verde National Park sites. Consider adding a site closer to emissions sources in NW New Mexico.

Initiate long-term monitoring / modeling of N and S in dry deposition via the Clean Air Status and Trends Network (CASTNet) at a site such as Molas Pass, which is at higher elevation than the one existing site at Mesa Verde NP. Consider adding an additional site closer to emissions sources in NW New Mexico.

Complete a full analysis of existing Wilderness Lakes data, including spatial and temporal trends and correlation of measurements with watershed or lake characteristics.

Support a suite of ecological studies in order to measure potential harmful effects of N deposition on natural resources across an elevation gradient. The studies should include an observational component aimed at documenting changing ambient conditions, but experimental manipulations should also be used to understand cause and effect relationships in addition to potential future responses. These studies should be modeled after those conducted in the Colorado Front Range, California, etc.

Visibility

Most visibility monitoring in the Four Corners is unevenly distributed (or restricted) to Class I areas. Therefore, visibility monitoring within these Class I areas is not conducive of a regional trends assessment, especially because they are based on a very few site-specific particulate measurements. Furthermore, the regional monitoring of visibility is desirable, because it can assist with the protection of Class I areas and EPA's regional haze rule. Additionally, regional monitoring of visibility will better address the value that citizens place upon the vistas that exist outside of Class I areas, while recognizing how visibility impacts citizens' perceptions of air quality as a whole. In sum, it is highly desirable that we consider how visibility monitoring in the Four Corners region can be perfected, with the intent of making a *strong regional assessment*.

1. It is recommended that the monitoring sites at Mesa Verde and in the Weminuche resume photographic documentation.

2. Many previous studies of visibility in the Four Corners relate only to site-specific locations, and often conflict in their findings. A comprehensive assessment of historical data is needed, in order to determine regional trends or changes in visibility. Currently, it is very difficult not only to establish regional trend analyses, but also to compare them to historical baseline data.

3. Additional visibility monitoring should be established at locations in the region other than what exists in Class I areas. This additional monitoring:

   D. could be incorporated into existing monitoring sites;
   E. should include photographic documentation;
   F. and, it should specifically consider how topographical variations impact the measurement of visibility.

4. The apparent contribution of NOx emissions to wintertime visibility impairment is recommended for further study.

Carbon Monoxide, PM_{10} and Other Common Pollutants

No suggestions for additional monitoring of carbon monoxide, PM10 and other common pollutants are currently being proposed.

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RESPONSES TO "MONITORING" COMMENTS

(by Gordon Pierce)

1. Kandi & David LeMoine, 7/17/2007
"… I reviewed what the monitoring group put together, and I think they did an excellent work."

The workgroup would like to say thanks! (No changes to the report.)

2. BP, 7/13/2007
"While the Draft Report suggestion for addition of new monitoring sites will provide valuable insight to understanding air quality in the region, a detailed analysis of current monitoring data also needs to be conducted to identify trends in air quality. In addition, analyzing trends in monitoring data in conjunction with changes in emissions will provide an important understanding of atmospheric processes. Also, it may be possible to evaluate monitoring data to assist in understanding source receptor relationships.
Confidence limits need to be developed based on monitoring accuracy and precision to determine if observed trends in data are statistically significant or simply random variations in analytic methods. There are also bounding calculations that could be performed that may assist in determining how changes in emissions may change visibility. Such calculations would entail using the IMPROVE data and ratioing the concentrations to calculate the improvement in visibility and establish an upper bound of visibility improvement.
It is recommended that the Task Force conduct a detailed analysis of the IMPROVE monitoring data in the region since BP believes that such an analysis would assist in developing meaningful strategies for improving air quality in the region. BP would welcome the opportunity to assist in establishing a scope of work for such an activity."

(Full response to be written by Sylvia Oliva.) The workgroup agrees that it would be nice to do more with trends analyses, confidence limits and IMPROVE data analyses. However, this was much more work than the workgroup had time to do. (No changes to the report.)

3. Jeanne Hoadley, 7/10/2007
"I would find it helpful if the wind roses on the maps were labeled with the station name."

The workgroup debated extensively as to how much information should be included on the wind rose maps. It was felt that adding more information would make the maps too cluttered and that station names should be presented separately. Thus, maps with only the station names and elevations are presented immediately preceding the wind rose maps. (No changes to the report.)

4. Jeanne Hoadley, 7/10/2007
"Under existing ozone data for the four corners region it says a Navajo Nation site is scheduled to begin operating in Shiprock but doesn't say when. If it is scheduled this implies we know when and we should say. If we don't know when we should say it is expected to begin operating soon."

At the time this subsection was written, there was not a specific date as to exactly when the Navajo Nation would be able to get their new air monitoring site fully operational. In further conversations with the Navajo Nation, the date is still uncertain due to electrical power issues. The report will be revised so that the text reads that the site is planned to commence operation by the end of 2007. (See report for revision under OZONE AND PRECURSOR GASES subsection, "Existing Ozone Data for the Four Corners Region".)

5. Jeanne Hoadley, 7/10/2007
"Under existing ozone data for the four corners region it says a Navajo Nation site is scheduled to begin operating in Shiprock but doesn't say when. If it is scheduled this implies we know when and we should say. If we don't know when we should say it is expected to begin operating soon.
The next sentence has a typo...the "closest" Arizona site."

Thank you for catching the typo. The word will be revised from "closes" to "closest". (See report for revision under OZONE AND PRECURSOR GASES subsection, "Existing Ozone Data for the Four Corners Region".)

6. Mark Jones, 7/10/2007
"Comment on behalf of Roy Paul, "Why is there no ozone monitoring on the Western Slope of Colorado?""

There are questions as to whether this comment is referring to the southwest/Four Corners area of Colorado or further north, such as around Mesa and Garfield counties in Colorado. For the southwest/Four Corners area, which is the focus of this workgroup, ozone monitoring is currently performed at four locations in Colorado. These locations are shown on the map in the "Ozone and Precursor Gases" subsection of the report. In addition, for recommendation #2 in the subsection, a passive ozone study was performed in the area during August 2007 using monies recently appropriated by the Colorado legislature. A revision to address this is made under recommendation #2. (See report for revision under OZONE AND PRECURSOR GASES subsection, recommendation #2.)

7. Jeanne Hoadley, 7/10/2007
"The pollutants in the header seem to be out of place in this table."

This appears to have been an issue with the software and comment version of the report on the website. The tables are correct in the actual report. (No changes to the report.)

8. Jeanne Hoadley, 7/10/2007
"Again the header in this table is messed up, making it impossible to understand."

This appears to have been an issue with the software and comment version of the report on the website. The tables are correct in the actual report. (No changes to the report.)

9. Jeanne Hoadley, 7/10/2007
"Mercury- Rationale and Benefits. It is not clear to me why Weminuche Wilderness is singled out here...there are many other Class 1 areas in or near this region."

(Full response to be written by Koren Nydick.) The commenter is correct in that other Class 1 areas are in the region. Weminuche was simply being used as an example. Mercury will be clarified in the report and other Class 1 areas will also be listed or mapped. (See revisions from Koren Nydick.)

Response to BP's Comments

(by Sylvia Oliva)

"Detailed analysis [analyses] of current monitoring data" including trends and back trajectories are already available on the Interagency Monitoring for the Projected Visual Environment, IMPROVE, web site (http://vista.cira.colostate.edu/improve/). Mesa Verde National Park data reaches back to the early 1990s. The highest standard possible for "accuracy and precision" of IMPROVE filters is well-established by the monitoring analysis agency: Crocker Nuclear Labs, University of California at Davis.

IMPROVE filter analyses include x-ray spectroscopy and related techniques. The filters themselves are of several different materials to best trap different aerosols and particulates. (This is why, unfortunately, data availability is traditionally in arrears for 12 to18 months.) Furthermore, any changes in filter composition or analysis protocol through the years are precisely notated in the preamble for accessing raw data for either single or groups of IMPROVE sites, single or groups of parameters.

It indeed would contribute to important understanding of atmospheric processes to take IMPROVE trend data (already available as previously mentioned) with emissions changes to assist in "understanding source-receptor relationship[s]." The caveat, here is that Mesa Verde data is not truly representative of visibility impairment in that the park's physical location (and therefore its IMPROVE site) is really not within the impairment atmosphere, contrary to other parks, e.g. Grand Canyon NP, Yellowstone, NP, or the Great Smokies NP. Rather, the visitor at Mesa Verde sees visibility impairment from outside. Likely, Mesa Verde IMPROVE data might be matched as background with other IMPROVE station data.

So, such a tremendously laudable project correlating trends with emissions sources is not within the present financial means and scope of the current task force.

Dramatic improvements in computer processing power the past two years will quite revolutionize modeling techniques. If these techniques are already incorporated into modeling software, establishing "an upper bound of visibility improvement" may well be a more realistic task than heretofore. (See Marufu, L. T. et al, The 2003 North American electrical blackout: An accidental experiment in atmospheric chemistry, Geophys. Res. Lett., 31, L13106, doi:10.1029/2004GL019771. "The dramatic improvement in air quality during the blackout may result from underestimation of emissions from power plants, inaccurate representation of power plant effluent in emission models or unaccounted for atmospheric chemical reaction(s).")

Appendices

Acronyms

Acronyms

µeq/L	micro-equivalents per liter
µg/L	micrograms per liter
$\mu g/m^3$	micrograms per cubic meter
<	less than
>	greater than
°C	degrees Centigrade
°F	degrees Fahrenheit
4CAQTF	Four Corners Air Quality Task Force
AAQS	Ambient Air Quality Standards
AC	Alternating Current
ACI	Activated Carbon Injection
A/F	Air/Fuel
AFR(s)	Air/Fuel Ratio
AFRC(s)	Air/Fuel Ratio Controllers
AFUDC	Allowance For Funds During Construction
aka	also known as
ANGEL	Airborne Natural Gas Emission LIDAR
APCD	Air Pollution Control Division
APD	Application for Permit to Drill
APS	Arizona Public Service
AQI	Air Quality Index
AQRV	Air Quality Related Value
AQS	Air Quality Standard
AQTSD	Air Quality Technical Support Document
ARM	Air Resource Management
ARS	Agricultural Resource Service
ASTM	American Society for Testing and Materials
ASU	Air Separation Unit
AWMA	Air & Waste Management Association
AZ	Arizona
B&W	Babcock and Wilcox
BACM	Best Available Control Measure
BACT	Best Available Control Technology
BAGI	Backscatter Absorption Gas Imaging
BART	Best Available Retrofit Technology
Bbl/day	barrels per day
Bcf	billion cubic feet
bhp	Brake Horsepower
BHP	BHP Billiton, Ltd.
BLM	Bureau of Land Management (U.S. Department of the Interior)
BMP(s)	Best Management Practices
BTEX	Benzene, Toluene, Ethyl-benzene, Xylene
Btu/kw-hr	British Thermal Units per Kilowatt Hour
CA	California
CAA	Clean Air Act
Ca	Calcium
CaCl	Calcium Chloride
CaCO3	Calcium Carbonate
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CALPUFF	California PUFF Dispersion Model
CaO	Calcium Oxide (Lime)
CARB	California Air Resources Board

CARE	Citizens Against Ruining our Environment
CAS	Chemical Abstracts Service
CASAC	Clean Air Scientific Advisory Committee
CaSO4	Calcium Sulfate
CASTNET	Clean Air Status and Trends Network
CB-DPF	Catalyst-Based Diesel Particulate Filter
CBM	Coal Bed Methane
CBNG	Coalbed Natural Gas
CCAG	Climate Change Advisory Group (New Mexico)
CCC	Colorado Climate Center
CCR	Colorado Code of Regulations
CCS	Carbon Capture and Sequestration
CCV	Closed Crankcase Ventilation
CCX	Chicago Climate Exchange
CDNR	Colorado Department of Natural Resources
CDOT	Colorado Department of Transportation
CDOW	Colorado Division of Wildlife
CDPHE	Colorado Department of Public Health and Environment
CDPHE-APCD	Colorado Department of Public Health and Environment – Air Pollution Control Division
CE	Cumulative Effects
CEC	California Energy Commission
CEDF	Clean Environment Development Facility
CEM	Continuous Emission Monitor
CEMS	Continuous Emission Monitoring System
CFB	Circulating Fluidized Bed and/or Coal-fired Boiler
CFLs	Compact Fluorescent Light bulbs
CFR	Code of Federal Regulations
Cfs	Cubic Feet per Second
CGS	Colorado Geological Survey
CH2	Methylene
CH3	Methyl Group
CH4	Methane
CHP	Combined Heat and Power
CI	Compression Ignition
Cl	Chloride
CNG	Compressed Natural Gas
CO	Carbon Monoxide and/or Colorado
CO2	Carbon Dioxide
COA	Conditions of Approval
CoAgMet	Colorado Agricultural Meteorological Network
COBRA	CO-Benefits Risk Assessment
COE	Cost of Energy
COGCC	Colorado Oil and Gas Conservation Commission
COM	Continuous Opacity Monitor
CPANS/ PNWIS	Canadian Prairie and Northern Section/Pacific Northwest International Section
CTG	Control Techniques Guideline
CWCS	Comprehensive Wildlife Conservation Strategy
DC	Direct Current
DCS	Distributed Control System
DEIS	Draft Environmental Impact Statement
DEP	Department of Environmental Protection
DEQ	Department of Environmental Quality
DER	Distributed Energy Resources
DIAL	Differential Absorption LIDAR
DLN	Dry Low NOX

DO	Dissolved Oxygen
DOAS	Differential Optical Absorption Spectroscopy
DOC	Diesel Oxidation Catalyst
DOE	U.S. Department of Energy
DPA	Dinè Power Authority
DREF	Desert Rock Energy Facility
DPF	Diesel Particulate Filter
DR	Demand Response
DRMP	Draft Resource Management Plan
DSIRE	Database of State Incentives for Renewable Energy
DV	Deciview
E	East
E&P	Exploration and Production
EA	Environmental Assessment
EAC	Early Action Compact
EBETS	Economic Incentives-Based Emission Trading System
ECBMR	Enhanced Coal Bed Methane Recovery
ECM	Electronic Control Module
EE	Energy Efficiency
EEREC	Energy Efficiency, Renewable Energy and Conservation
EGR	Exhaust Gas Recirculation
eGRID	Emissions and Generation Integrated Resource Database
EGU	Electric Generating Unit
EIS	Environmental Impact Statement
ENGR	Enhanced Natural Gas Recovery
EOR	Enhanced Oil Recovery
EPA	U.S. Environmental Protection Agency
EPCA	Energy Policy and Conservation Act
EPD	Environmental Protection Division
EPRI	Electric Power Research Institute
ERMS	Emission Reduction Market System
ESP	Electrostatic Precipitator
ETC	Environmental Technology Council
ETS	Emission Trading System
F	degrees Fahrenheit
F-T	Fischer-Tropsch
FAQs	Frequently Asked Questions
FBC	Fuels Borne Catalyst
FCOTF	Four Corners Ozone Task Force
FCPP	4 Corners Power Plant
FEIS	Final Environmental Impact Statement
FGD	Flue Gas Desulfurization
FIP	Federal Implementation Plan
FLAG	Federal Land Managers' AQRV Workgroup
FLM	Federal Land Manager
FR	Federal Register
FS	Forest Service (U.S. Department of Agriculture)
Ft	feet
FTF(s)	Flow Through Filter
FY	Fiscal Year
G	gram
g/bhp-hr	grams per brake horsepower-hour
g/hp-hr	grams per horsepower-hour
GF	Growth Fund
GHG(s)	Greenhouse Gases
GIS	Geographic Information System

GOR	Gas Oil Ratio
GVW	Gross Vehicle Weight
GWh/yr	Gigawatt hours per year
H+	Hydrogen ion
H2O	Water
H2S	Hydrogen Sulfide
H2SO4	Sulfuric Acid
HAP(s)	Hazardous Air Pollutants
HC(s)	Hydrocarbons
HF	Hydrogen Fluoride
Hg	Mercury
HCHO	Formaldehyde
HNO3	Nitric Acid
hp	Horsepower
HRSG	Heat Recovery Steam Generator
HRVOC(s)	Highly Reactive Volatile Organic Compounds
I&M	Inspection and Maintenance
IBEMP	Innovation Technology and Best Energy-Environment Management Practices
ICE	Internal Combustion Engine
IGCC	Integrated Gasification Combined Cycle
IMPROVE	Interagency Monitoring of Protected Visual Environment
ISA	Instrument Systems and Automation Society
ISCST3	Industrial Source Complex – Short Term Dispersion Model, Version 3
IWAQM	Inter-Agency Work Group on Air Quality Modeling
K	One Thousand Dollars or Potassium
kg/ha-yr	Kilograms per Hectare-Year
km	kilometer
Kwh	kilowatt hour
LAER	Lowest Achievable Emission Rate
lb	pound
lbs/mmBtu	pounds of emissions/million btu heat input
lbs/MWh	pounds of emission/Megawatt-hour
LDAR	Leak Detection and Repair
LEED	Leadership in Energy Efficiency and Design
LiCl	Lithium Chloride
LIDAR	Light Detection and Ranging
LLC	Limited Liability Company
LNC	Lean NOX Catalyst
LNG	Liquefied Natural Gas
LoTOx	Low Temperature Oxidation Technology
LP	Limited Partnership
LPG	Liquefied Petroleum Gas
LTO	Low Temperature Oxidation
LWV	League of Women Voters
MACT	Maximum Achievable Control Technology
MC	Multi-Contact
mcf	one thousand cubic feet
MDN	Mercury Deposition Network
Mg	Magnesium
mg/L	milligrams per liter
mg/m3	micrograms per cubic meter
microg/g	micrograms per gram
MIT	Massachusetts Institute of Technology
MM	One Million Dollars
Mm^{-1}	Inverse Megameters
mmBtu	One Million British Thermal Units

MMcf/day	million cubic feet per day
MMscf/day	million standard cubic feet per day
MMV	Measurement, Monitoring and Verification Techniques
MOA	Memorandum of Agreement
MOU	Memorandum of Understanding
mph	Miles Per Hour
MPO	Metropolitan Planning Organization
MSI	Mountain Studies Institute
MW	Megawatt
N	Nitrogen
N2	Nitrogen gas
N2O	Nitrous Oxide
N2O3	Nitrogen Oxide
N2O5	Nitric Pentoxide
NA	Not Applicable
Na	Sodium
NAAQS	National Ambient Air Quality Standard
NADP	National Atmospheric Deposition Program
NEG	Net Excess Generation
NESHAPS	National Emission Standards for Hazardous Air Pollutants
NG	Natural Gas
NGCC	Natural Gas Combined Cycle
NGL	natural gas liquids
NH3	Ammonia
NI	no information
NM	New Mexico
NMED-AQB	New Mexico Environment Department-Air Quality Bureau
NMEMNRD	New Mexico Energy, Minerals and Natural Resources Department
NMHC	Non-Methane Hydrocarbon
NMOC	Non-Methane Organic Compounds
NMOCD	New Mexico Oil Conservation Division
NMOG	Non-Methane Organic Gas
NMOGA	New Mexico Oil and Gas Association
NMRPC	New Mexico Public Regulation Commission
NMUSA	New Mexico Utility Shareholders Alliance
NNEPA	Navajo Nation Environmental Protection Agency
No.	Number
NO	Nitric Oxide
NO2	Nitrogen Dioxide
NO3	Nitrate
NOx	Nitrogen Oxides
NOx/mmBtu	Nitrogen Oxides per million British Thermal Units
NOAA	National Oceanic & Atmospheric Administration
NP	National Park
NPS	National Park Service
NPV	Net Present Value
NRDC	Natural Resources Defense Council
NSCR	Non-Selective Catalytic Reduction
NSPS	New Source Performance Standards
NSR	New Source Review
NTN	National Trends Network
NW	Northwest
NWS	National Weather Service
NYCRR	New York Codes, Rules and Regulations
O&M	Operation and Maintenance
O2	Oxygen

O3	Ozone
OCD	Oil Conservation Division
OCV	Open Crankcase Ventilation
OECA	Office of Enforcement and Compliance Assurance
OH	Hydroxide
ONG	Onshore Natural Gas
OP-FTIR	Open-Path Fourier Transform Infrared
Oz	Ounce
PAH(s)	Polycyclic Aromatic Hydrocarbon
PC	Pulverized Coal
P/H	Power to Heat Ratio
pH	Acidity Measurement Unit
PLC	Programmable Logic Controller
PM	Particulate Matter
PM_{10}	Particulate Matter (effective diameter < 10 micrograms)
$PM_{2.5}$	Fine Particulate Matter (effective diameter < 2.5 micrograms)
POWID	Power Industry Division
ppb	parts per billion
ppm	parts per million
PRO	Partner Reported Opportunities
PSD	Prevention of Significant Deterioration
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PSNM	Public Service of New Mexico
PV	Photovoltaic
QA	Quality Assurance
QC	Quality Control
R&D	Research and Development
RACM	Reasonably Available Control Measures
RACT	Reasonably Available Control Technology
RAWS	Remote Automated Weather Stations
RC&D	Resource Conservation and Development
RE	Renewable Energy
REC(s)	Renewable Energy Credit
RH	Relative Humidity
RIA	Regulatory Impact Analyses
RICE	Reciprocating Internal Combustion Engine
RMP	Resource Management Plan
RMPPA	Resource Management Plan Planning Area
ROD	Record of Decision
ROG	Reactive Organic Gas
ROI	Return on Investment
RPM	Revolutions Per Minute
RPS	Renewable Portfolio Standards
RRC	Rebecca Reynolds Consulting
RVP	Reid Vapor Pressure
S	Sulfur
SAR	Specific Absorption Rate
scfh	standard cubic feet per hour of gas flow
SC	Supercritical
SCPC	Supercritical Pulverized Coal
SCR	Selective Catalytic Reduction
SEP(s)	Supplemental Energy Payment
SI	Spark-Ignition Engine
SIP	State Implementation Plan

SJ	San Juan
SJGS	San Juan Generating Station
SLAMS	State/Local Air Monitoring Stations
SNCR	Selective Non-Catalytic Reduction
SO2	Sulfur Dioxide
SO2/mmBtu	Sulfur Dioxide/one million British Thermal Units
SOTA	State of the Art
SOx	Sulfur Oxides
SPMS	Special Purpose Monitoring Stations
sq mi	Square Miles
SRI	Southern Research Institute
SRP	Salt River Project Agricultural Improvement and Power District
SUIT	Southern Ute Indian Tribe
SW	Southwest
SWD	Salt Water Disposal Well
SWEEP	Southwest Energy Efficiency Project
TAG	Technical Assessment Guide
TBD	To Be Determined
TDLAS	Tunable Diode Laser Absorption Spectroscopy
TDS	Total Dissolved Solids
TEG	Triethylene Glycol
TF	Task Force
THC	Total Hydrocarbons
TPH	Total Petroleum Hydrocarbons
tpy	tons per year
TSD	technical support document
U.S.C.	United States Code
ULSD	Ultra Low Sulfur Diesel
US	United States
USC	Ultra Supercritical Coal
USCPC	Ultra-Supercritical Pulverized Coal
USDA	U.S. Department of Agriculture
USDI	U.S. Department of the Interior
USFS	U.S. Forest Service
USGS	U.S. Geological Survey
UST	Underground Storage Tank
UT	Utah
VISTAS	Voluntary Innovative Strategies for Today's Air Standards Program
VLUA	Vallecito Land Use Association
VMT	Vehicle Miles Traveled
VOC(s)	Volatile Organic Compounds
VRM	Visual Resource Management
VRP	Visibility Reducing Particles
VRU	Vapor Recovery Unit
vs.	Versus
W	West
W/m2	Watts per square meter
W/O	without
WDEQ	Wyoming Department of Environmental Quality
WESTAR	Western States Air Resource Council
WRAP	Western Regional Air Partnership

Definitions

Definitions

3-way catalyst: A catalyst containing both reduction and oxidation catalyst materials that converts Oxides of Nitrogen (NO_X), Carbon Monoxide (CO), and Non-Methane Hydrocarbons (NMHCs) to Nitrogen (N_2), Carbon Dioxide (CO_2), and water H_2O.

AP-42: An U.S. EPA compendium of emission factors for different source types. An emission factor is a representative value that attempts to relate the quantity of a pollutant released to the atmosphere with an activity associated with the release of that pollutant. These factors are usually expressed as the weight of pollutant divided by a unit weight, volume, distance, or duration of the activity emitting the pollutant (e. g., kilograms of particulate emitted per megagram of coal burned). For additional information, see EPA's website at http://www.epa.gov/ttn/chief/ap42/.

Absorption: The process by which the energy of a photon is taken up by another entity.

Acid Deposition: A comprehensive term for the various ways acidic compounds precipitate from the atmosphere and deposit onto surfaces. It can include: 1) wet deposition by means of acid rain, fog, and snow; and 2) dry deposition of acidic particles (aerosols).

Acid Rain: Rain which is especially acidic (pH <5.2). Principal components of acid rain typically include nitric and sulfuric acid. These may be formed by the combination of nitrogen and sulfur oxides with water vapor in the atmosphere.

Acid Rain Program: The overall goal of the Acid Rain Program is to achieve significant environmental and public health benefits through reductions in emissions of sulfur dioxide (SO2) and nitrogen oxides (NOx)—the primary causes of acid rain. To achieve this goal at the lowest cost to society, the program employs both traditional and innovative, market-based approaches for controlling air pollution. In addition, the program encourages energy efficiency and pollution prevention.

Activated Carbon Injection (ACI) Technology: In ACI technology, powdered activated carbon (PAC) sorbent is injected into the flue gas at a location in the duct preceding the particulate matter (PM) control device, which usually is an electrostatic precipitator or a fabric filter. The PAC sorbent binds with the mercury in the flue gas in the duct and in the PM control device. Subsequently, the mercury-containing PAC is captured in the PM control device.
Carbon Capture and Sequestration (CCS): Carbon capture and storage is an approach to mitigating climate change by capturing carbon dioxide (CO2) from large point sources such as power plants and subsequently storing it away safely instead of releasing it into the atmosphere. Technology for capturing of CO2 is already commercially available for large CO2 emitters, such as power plants. Storage of CO2, on the other hand, is a relatively untried concept and as yet (2007) no power plant operates with a full carbon capture and storage system. Currently, the United States government has approved the construction of the world's first CCS power plant, FutureGen, while BP has indicated that it intends to develop a 350 MW carbon capture and storage plant in Scotland, in which the carbon from a natural gas fired generator plant will be stripped out and pumped into the Miller field in the North Sea.

Add-On Control Device: An air pollution control device such as carbon absorber or incinerator that reduces the pollution in exhaust gas. The control device usually does not affect the process being controlled and thus is "add-on" technology, as opposed to a scheme to control pollution through altering the basic process itself. See also pollution prevention.

Adsorber: An emissions control device that removes volatile organic compounds (VOCs) from a gas stream as a result of the gas attaching (adsorbing) onto a solid matrix such as activated carbon.

Adsorption (Physical and Chemical): capability of all solid substances to attract to their surfaces molecules of gases or solutions with which they are in contact. Solids that are used to adsorb gases or dissolved substances are called adsorbents; the adsorbed molecules are usually referred to collectively as the adsorbate. An example of an excellent adsorbent is the charcoal used in gas mask.

Adverse Health Effect: A health effect from exposure to air contaminants that may range from relatively mild temporary conditions, such as eye or throat irritation, shortness of breath, or headaches to permanent and serious conditions, such as birth defects, cancer or damage to lungs, nerves, liver, heart, or other organs.

Aerosol: Particles of solid or liquid matter that can remain suspended in air from a few minutes to many months depending on the particle size and weight.

Afterburner: An air pollution abatement device that removes undesirable organic gases through incineration.

Agricultural Burning: The intentional use of fire for vegetation management in areas such as agricultural fields, orchards, rangelands, and forests.

Air: So called "pure" air is a mixture of gases containing about 78 percent nitrogen; 21 percent oxygen; less than 1 percent of carbon dioxide, argon, and other gases; and varying amounts of water vapor. See also ambient air.

Air Monitoring: Sampling for and measuring of pollutants present in the atmosphere.

Air Pollutants: Amounts of foreign and/or natural substances occurring in the atmosphere that may result in adverse effects to humans, animals, vegetation, and/or materials. (See also air pollution.)

Air Pollution: Degradation of air quality resulting from unwanted chemicals or other materials occurring in the air. (See also air pollutants.)

Air Quality Index (AQI): A numerical index used for reporting severity of air pollution levels to the public. The AQI incorporates five criteria pollutants -- ozone, particulate matter, carbon monoxide, sulfur dioxide, and nitrogen dioxide -- into a single index. The new index also incorporates the 8-hour ozone standard and the 24-hour $PM_{2.5}$ standard into the index calculation. AQI levels range from 0 (Good air quality) to 500 (Hazardous air quality). The higher the index, the higher the level of pollutants and the greater the likelihood of health effects. The AQI incorporates an additional index category -- unhealthy for sensitive groups -- that ranges from 101 to 150. In addition, the AQI comes with more detailed cautions.

Air Quality Model: A mathematical relationship between emissions and air quality which simulates on a computer the transport, dispersion, and transformation of compounds emitted into the air.

Air Quality Standard (AQS): The prescribed level of a pollutant in the outside air that should not be exceeded during a specific time period to protect public health. Established by both federal and state governments. (See also ambient air quality standards.)

Air separation membranes: Change the proportion of nitrogen to oxygen in air. A membrane can be optimized to either enrich the oxygen content or to enrich the nitrogen content.

Airshed: Denotes a geographical area that shares the same air because of topography, meteorology, and climate.

Air to Fuel Ratio Controller (AFRC): Device using a closed loop control based on the readings of an exhaust gas oxygen sensor to determine the air/fuel ratio.

Air Toxics: A generic term referring to a harmful chemical or group of chemicals in the air. Substances that are especially harmful to health, such as those considered under U.S. EPA's hazardous air pollutant program, are considered to be air toxics. Technically, any compound that is in the air and has the potential to produce adverse health effects is an air toxic.

Alcohol Fuels: Alcohol can be blended with gasoline for use as transportation fuel. It may be produced from a wide variety of organic feedstock. The common alcohol fuels are methanol and ethanol. Methanol may be produced from coal, natural gas, wood and organic waste. Ethanol is commonly made from agricultural plants, primarily corn, containing sugar.

Alkane: Chemical compounds that consist only of the elements carbon (C) and hydrogen (H) (i.e. hydrocarbons), where each of these atoms are linked together exclusively by single bonds.

Alternative Fuels: Fuels such as methanol, ethanol, natural gas, and liquid petroleum gas that are cleaner burning and help to meet mobile and stationary emission standards. These fuels may be used in place of less clean fuels for powering motor vehicles.

Ambient Air: The air occurring at a particular time and place outside of structures. Often used interchangeably with "outdoor air." (See also air.)

Ambient Air Quality Standards (AAQS): Health- and welfare-based standards for outdoor air which identify the maximum acceptable average concentrations of air pollutants during a specified period of time. (See also NAAQS and Criteria Air Pollutant.)

American Society for Testing and Materials (ASTM): A nonprofit organization that provides a forum for producers, consumers, and representatives of government and industry, to write laboratory test standards for materials, products, systems, and services. ASTM publishes standard test methods, specifications, practices, guides, classifications, and terminology.

Amines: Amines are organic compounds that contain nitrogen as the key atom. Structurally, amines resemble ammonia. The advantage of an amine CO_2 removal system is that it has a lower capital cost than any of the current physical solvent processes. The disadvantage is that an amine system uses large amounts of steam heat for solvent regeneration and energy to re-cool the amine, making it a less energy efficient process**.**

Ammonia (NH_3): A pungent colorless gaseous compound of nitrogen and hydrogen that is very soluble in water and can easily be condensed into a liquid by cold and pressure. Ammonia reacts with NOx to form ammonium nitrate -- a major $PM_{2.5}$ component in the Western United States.

Ammonia slip: Ammonia emissions from SCR systems.

Area Sources: Those sources for which a methodology is used to estimate emissions. This can include area-wide, mobile and natural sources, and also groups of stationary sources (such as dry cleaners and gas stations). Sources which are not reported as individual point sources are included as area sources. The federal air toxics program defines a source that emits less than 10 tons per year of a single hazardous air pollutant (HAP) or 25 tons per year of all HAPs as an area source.

Aromatic compounds: An organic chemical compound that contains aromatic rings (arenes) like benzene, pyridine, or indole and possessing an aroma, fragrance, flavor, smell, or odor

Asthma: A chronic inflammatory disorder of the lungs characterized by wheezing, breathlessness, chest tightness, and cough.

Atmosphere: The gaseous mass or envelope of air surrounding the Earth. From ground-level up, the atmosphere is further subdivided into the troposphere, stratosphere, mesosphere, and the thermosphere.

Attainment Area: A geographical area identified to have air quality as good as, or better than, the national ambient air quality standards (NAAQS). An area may be an attainment area for one pollutant and a nonattainment area for others.

Baghouse: An air pollution control device that traps particulates by forcing gas streams through large permeable bags usually made of glass fibers.

Banking: A provision used in emissions trading programs that allows a facility to accumulate credits for reducing emissions beyond regulatory limits (emission reduction credits) and then use or sell those credits at a later date.

Baseline: A starting point or condition against which future changes are measured. For air quality emissions, the known emissions in a given year that future emissions can be measured against.

Benzene, Toluene, Ethyl Benzene, Xylene (BTEX): Group of volatile organic compounds (VOCs) found in petroleum hydrocarbons, such as gasoline, and other common environmental contaminants.

Best Available Control Measure (BACM): A term used to describe the "best" measures (according to U.S. EPA guidance) for controlling small or dispersed sources of particulate matter and other emissions from sources such as roadway dust, woodstoves, and open burning.

Best Available Control Technology (BACT): The most up-to-date methods, systems, techniques, and production processes available to achieve the greatest feasible emission reductions for given regulated air pollutants and processes. BACT is a requirement of NSR (New Source Review) and PSD (Prevention of Significant Deterioration).

Best Available Retrofit Technology (BART): An air emission limitation that applies to existing sources and is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of source. (See also Best Available Control Technology.)

Bioenergy: Useful, renewable energy produced from organic matter, which may either be used directly as a fuel or processed into liquids and gases.

Biofuels: Liquid fuels and blending components produced from biomass (plant) feedstocks, used primarily for transportation.

Biogenic Source: Biological sources such as plants and animals that emit air pollutants such as volatile organic compounds. Examples of biogenic sources include animal management operations, and oak and pine tree forests. (See also natural sources.)

Biomass: Organic nonfossil matter of a biological origin available on a renewable basis. Biomass includes forest and mill residues, agricultural crops and wastes, wood and wood wastes, animal wastes, livestock operation residues, aquatic plants, fast-growing trees and plants, and municipal and industrial wastes.

Boiler: A device for generating steam for power, processing, or heating purposes or for producing hot water for heating purposes or hot water supply. A device where heat converts water to steam.

Carbon (CO2) Capture and Storage: CO2 capture and storage involves capturing the CO2 arising from the combustion of fossil fuels, as in power generation, or from the preparation of fossil fuels, as in natural-gas processing. Capturing CO2 involves separating the CO2 from some other gases. For example in the exhaust gas of a power plant other gases would include nitrogen and water vapor. The CO2 must then be transported to a storage site where it will be stored away from the atmosphere for a long period of time. In order to have a significant effect on atmospheric concentrations of CO2, storage reservoirs would have to be large relative to annual emissions. (IPCC, 2001). Sometimes referred to as sequestration.

Carbon Dioxide (CO_2): A colorless, odorless gas that occurs naturally in the Earth's atmosphere. Significant quantities are also emitted into the air by fossil fuel combustion.

Carbon mass balance: An accounting of material entering and leaving a system.

Carbon Monoxide (CO): A colorless, odorless gas resulting from the incomplete combustion of hydrocarbon fuels. CO interferes with the blood's ability to carry oxygen to the body's tissues and results in numerous adverse health effects. CO is a criteria air pollutant.

Carcinogen: A cancer-causing substance. (See also cancer.)

CAS Registry Number: The Chemical Abstracts Service Registry Number (CAS) is a numeric designation assigned by the American Chemical Society's Chemical Abstract Service and uniquely identifies a specific compound. This entry allows one to conclusively identify a material regardless of the name or naming system used.

Catalyst: A substance that can increase or decrease the rate of a chemical reaction between the other chemical species without being consumed in the process.

Catalyst Deactivation: Poisoning is a primary factor in deactivation, with blockage and physical destruction of equal importance to catalyst life. When the surface or pores of the catalyst are blocked, flue gas/NOx cannot contact the catalyst.

Catalytic converter: The mechanism by which the catalyst will either oxidize (oxidation catalyst) a CO or fuel molecule or reduce (reduction catalyst) a NO_X molecule.

Cation: A positively-charged ion, which has fewer electrons than protons. An ion is an atom or group of atoms which have lost or gained one or more electrons, making them negatively or positively charged.

Cell Burner: Cell burner boiler means a wall-fired boiler that utilizes two or three circular burners combined into a single vertically oriented assembly that results in a compact, intense flame. Cell burner boilers have closely spaced clusters of two or three burners (i.e., cells) that together result in a single flame. In addition, the boilers are, like many wall-fired boilers, relatively compactly designed with small furnaces.

Chromatography: A set of laboratory techniques for separation of mixtures. One such procedure includes passing a mixture dissolved in a "mobile phase" through a stationary phase, which separates the analyte to be measured from other molecules in the mixture and allows it to be isolated.

Chronic Exposure: Long-term exposure, usually lasting one year to a lifetime.

Chronic Health Effect: A health effect that occurs over a relatively long period of time (e.g., months or years). (See also acute health effect.)

Class I Area: Under the Clean Air Act, a Class I area is one in which visibility is protected more stringently than under the national ambient air quality standards; includes national parks, wilderness area, monuments and other areas of special national and cultural significance.

Clean Air Act (CAA): A federal law passed in 1970 and amended in 1974, 1977 and 1990 which forms the basis for the national air pollution control effort. Basic elements of the act include national ambient air quality standards for major air pollutants, mobile and stationary control measures, air toxics standards, acid rain control measures, and enforcement provisions.

Clean Air Mercury Rule: On March 15, 2005, EPA issued the Clean Air Mercury Rule to permanently cap and reduce mercury emissions from coal-fired power plants for the first time ever. This rule makes the United States the first country in the world to regulate mercury emissions from utilities.

Cleaner-Burning Gasoline: Gasoline fuel that results in reduced emissions of carbon monoxide, nitrogen oxides, reactive organic gases, and particulate matter, in addition to toxic substances such as benzene and 1,3-butadiene.

Coal bed methane (CBM): Methane found in coal seams.

Code of Federal Regulations (CFR): The codification of the general and permanent rules published in the Federal Register by the executive departments and agencies of the Federal Government pursuant to authority derived from the Clean Air, Water, and other environmental acts.

Cogeneration: See combined heat and power.

Combined Cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. Such designs increase the efficiency of the electric generating unit.

Combined Heat and Power (CHP) Plant: A plant designed to produce both heat and electricity from a single heat source. Note: This term is being used in place of the term "cogenerator" that was used by EIA in the past. CHP better describes the facilities because some of the plants included do not produce heat and power in a sequential fashion and, as a result, do not meet the legal definition of cogeneration specified in the Public Utility Regulatory Policies Act (PURPA).

Combustion: The act or instance of burning some type of fuel such as gasoline to produce energy. Combustion is typically the process that powers automobile engines, oil and gas-field engines, and power plant generators.

Compressed natural gas (CNG): A substitute for gasoline (petrol) or diesel fuel, made by compressing methane extracted from natural gas.

Concentrator: A reflective or refractive device that focuses incident insolation onto an area smaller than the reflective or refractive surface, resulting in increased insolation at the point of focus.
Conventional hydroelectric (hydropower) plant: A plant in which all of the power is produced from natural streamflow as regulated by available storage.

Condensate tank: Tank for storing condensate from oil and gas activity.

Condensate Tank Battery: Comprised of a single storage tank or a group of storage tanks with a design capacity less than or equal to 10,000 barrels per tank, used for the storage of condensate and located at an exploration and production facility.

Consent Decree: When a court case has been filed, the parties can resolve the case short of having a trial by entering into a joint agreement or by consenting to a judgment.

Continuous Emission Monitor (CEM): A type of air emission monitoring system installed to operate continuously inside of a smokestack or other emission source.

Continuous Sampling Device: An air analyzer that measures air quality components continuously. (See also Integrated Sampling Device.)

Control Techniques Guidelines (CTG): Guidance documents issued by U.S. EPA that define reasonably available control technology (RACT) to be applied to existing facilities that emit excessive quantities of air pollutants; they contain information both on the economic and technological feasibility of available techniques.

Cost-Effectiveness: The cost of an emission control measure assessed in terms of dollars-per-pound, or dollars-per-ton, of air emissions reduced.

Criteria Air Pollutant: An air pollutant for which acceptable levels of exposure can be determined and for which an ambient air quality standard has been set. Examples include: ozone, carbon monoxide, nitrogen dioxide, sulfur dioxide, and PM_{10} and $PM_{2.5}$. The term "criteria air pollutants" derives from the requirement that the U.S. EPA must describe the characteristics and potential health and welfare effects of these pollutants. The U.S. EPA periodically reviews new scientific data and may propose revisions to the standards as a result.

Cryogenic: production of very low temperatures and the behavior of materials at those temperatures below -150C.

Cyclone: An air pollution control device that removes larger particles -- generally greater than one micron -- from an air stream through centrifugal force.

Deciview: A measurement of visibility. One deciview represents the minimal perceptible change in visibility to the human eye.

Desiccant dehydrator: Device that uses moisture-absorbing salts to remove water from natural gas. In general, there are only minor air emissions from desiccant systems.

Diesel Engine: A type of internal combustion engine that uses low-volatility petroleum fuel and fuel injectors and initiates combustion using compression ignition (as opposed to spark ignition that is used with gasoline engines).

Diesel fuel emulsion: Emulsion of diesel and other fuel intended to reduce peak engine combustion temperatures and increase fuel atomization and combustion efficiency.

Diesel oxidation catalyst (DOC): Device that uses a chemical process to break down pollutants in the exhaust stream into less harmful components. Diesel oxidation catalysts can reduce emissions of particulate matter (PM) by 20% and hydrocarbons (HC) by 50% and carbon monoxide (CO) by approximately 40%.

Diesel particulate filter: Filter that collects or traps particulate matter (PM) in the exhaust.

Diffraction: Diffraction refers to various phenomena associated with wave propagation, such as the bending, spreading and interference of waves such as visible light.

Dispersion Model: See air quality model above.

Distributed Generation (Distributed Energy Resources): Refers to electricity provided by small, modular power generators (typically ranging in capacity from a few kilowatts to 50 megawatts) located at or near customer demand.

Dose: The amount of a pollutant that is absorbed. A level of exposure which is a function of a pollutant's concentration, the length of time a subject is exposed, and the amount of the pollutant that is absorbed. The concentration of the pollutant and the length of time that the subject is exposed to that pollutant determine dose.

Dose-Response: The relationship between the dose of a pollutant and the response (or effect) it produces on a biological system.

Drill rig: General term used to describe a wide variety of machines that create holes (usually called boreholes) and/or shafts in the ground, or to install wells.

Dry-bottom, Wall-fired: Dry bottom means the boiler has a furnace bottom temperature below the ash melting point and the bottom ash is removed as a solid. Wall-fired boiler means a boiler that has pulverized coal burners arranged on the walls of the furnace. The burners have discrete, individual flames that extend perpendicularly into the furnace area.

Dry Cooled Coal-Fired: Dry cooling operates without evaporation by passing the steam from the turbines through a set of finned pipes immediately beside the turbine and cooling the water by having large volumes of air driven by fans to condense the steam in the pipes.

Dust: Solid particulate matter that can become airborne.

Ecosystem: A self-sustaining association of plants, animals, and the physical environment in which they live.

Electric Generating Unit (EGU) – Clean Air Interstate Rule definition:
(a) Except as provided in paragraph (b) of this definition, a stationary, fossil-fuel-fired boiler or stationary, fossil fuel fired combustion turbine serving at any time, since the start-up of a unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.
(b) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of

the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (a) of this definition starting on the day on which the unit first no longer qualifies as a cogeneration unit.

Electric Utility: A corporation, person, agency, authority, or other legal entity or instrumentality aligned with distribution facilities for delivery of electric energy for use primarily by the public. Included are investor-owned electric utilities, municipal and State utilities, Federal electric utilities, and rural electric cooperatives. A few entities that are tariff based and corporately aligned with companies that own distribution facilities are also included.

Electrostatic Precipitator (ESP): An air pollution control device that removes particulate matter from an air stream by imparting an electrical charge to the particles for mechanical collection at an electrode.

Emission Factor: For stationary sources, the relationship between the amount of pollution produced and the amount of raw material processed or burned. For mobile sources, the relationship between the amount of pollution produced and the number of vehicle miles traveled. By using the emission factor of a pollutant and specific data regarding quantities of materials used by a given source, it is possible to compute emissions for the source. This approach is used in preparing an emissions inventory.

Emission Inventory: An estimate of the amount of pollutants emitted into the atmosphere from major mobile, stationary, area-wide, and natural source categories over a specific period of time such as a day or a year.

Emission Rate: The weight of a pollutant emitted per unit of time (e.g., tons / year).

Emission Standard: The maximum amount of a pollutant that is allowed to be discharged from a polluting source such as an automobile or smoke stack.

Emission trading system (ETS): Program wherein the governing authority (e.g., agency) issues a limited number of allocations in the form of certificates consistent with the desired or targeted level of emissions in an identified region or area. The sources of a particular air pollutant (e.g., NOx) are allotted certificates to release a specified number of tons of the pollutant. The certificate owners may choose either to continue to release the pollutant at current levels and use the certificates or to reduce their emissions and sell the certificates.

Enardo valve: Brand name for a pressure relief valve installed on condensate and other oil storage tanks to control evaporation and fugitive emission losses that result from flammable and hazardous petroleum vapor-producing products.

Energy Content: The amount of energy available for doing work. For example, the amount of energy in fuel available for powering a motor vehicle.

Energy Crops: Crops grown specifically for their fuel value. These include food crops such as corn and sugarcane, and nonfood crops such as poplar trees and switchgrass. Currently, two energy crops are under development: short - rotation woody crops, which are fast - growing hardwood trees harvested in five to eight years, and herbaceous energy crops, such as perennial grasses, which are harvested annually after taking two to three years to reach full productivity.

Energy Efficiency: Energy efficiency refers to products or systems using less energy to do the same or better job than conventional products or systems. Energy efficiency saves energy, saves money on utility bills, and helps protect the environment by reducing the amount of electricity that needs to be generated. When buying or replacing products or appliances for your home, look for the ENERGY STAR® label — the national symbol for energy efficiency. For more information on ENERGY STAR® labeled products, visit the ENERGY STAR® Web site.

Enhanced Gas Recovery and/or Enhanced Coal Bed Methane Recovery: To enhance coal bed methane recovery factors and production rates as a result of CO2 injection.
Burlington Resources has successfully injected CO2 into relatively high permeability coalbeds in the San Juan basin in the USA for several years. They are stimulating coalbed methane production and recovery. The injected CO2 is

adsorbed into the coal matrix and remains in the ground after completion of gas production. However, further testing and demonstration are needed to apply this process to low permeability reservoirs.

Enhanced Oil Recovery: Using CO_2 injection to enhance production from oil reservoirs.

Environmental Justice: The fair treatment of people of all races and incomes with respect to development, implementation, and enforcement of environmental laws, regulations, and policies.

EPA's Natural Gas STAR Program: The Natural Gas STAR Program is a flexible, voluntary partnership between U.S. EPA and the oil and natural gas industry. Through the program, U.S. EPA works with companies that produce, process, and transmit and distribute natural gas to identify and promote the implementation of cost-effective technologies and practices to reduce emissions of methane, a potent greenhouse gas.

Ethanol (also known as Ethyl Alcohol or Grain Alcohol, CH3-CH2OH): A clear, colorless flammable oxygenated hydrocarbon with a boiling point of 173.5 degrees Fahrenheit in the anhydrous state. However it readily forms a binary azetrope with water, with a boiling point of 172.67 degrees Fahrenheit at a composition of 95.57 percent by weight ethanol. It is used in the United States as a gasoline octane enhancer and oxygenate (maximum 10 percent concentration). Ethanol can be used in higher concentrations (E85) in vehicles designed for its use. Ethanol is typically produced chemically from ethylene, or biologically from fermentation of various sugars from carbohydrates found in agricultural crops and cellulosic residues from crops or wood. The lower heating value, equal to 76,000 Btu per gallon, is assumed for estimates in this report.

Evacuated Tube: In a solar thermal collector, an absorber tube, which is contained in an evacuated glass cylinder, through which collector fluids flows.

Evaporative Emissions: Emissions from evaporating gasoline, which can occur during vehicle refueling, vehicle operation, and even when the vehicle is parked. Evaporative emissions can account for two-thirds of the hydrocarbon emissions from gasoline-fueled vehicles on hot summer days.

Exhaust Gas Recirculation (EGR): An emission control method that involves recirculating exhaust gases from an engine back into the intake and combustion chambers. This lowers combustion temperatures and reduces NOx. (See also nitrogen oxides.)

Exceedance: A measured level of an air pollutant higher than the national or state ambient air quality standards. (See also NAAQS.)

Federal Implementation Plan (FIP): In the absence of an approved State Implementation Plan (SIP), a plan prepared by the U.S. EPA which provides measures that areas must take to meet the requirements of the Federal Clean Air Act.

Feedstock: The raw material that is required for some industrial process.

Flaring: Technique of igniting hydrocarbon gases to convert natural gas constituents (hydrocarbons, including BTEX and other Hazardous Air Pollutants) into less hazardous and atmospherically reactive compounds.

Flash emissions: Emissions resulting by a reduction in pressure and/or temperature when hydrocarbon liquids are dumped into the storage tank from the production separator.

Flow through filters (FTF): Filters for capture or oxidize particles, using a variety of media and regeneration strategies. The filter media can be either wire mesh or pertubated path metal foil.

Flue gas: Exhaust gases following combustion.

Fly Ash: Air-borne solid particles that result from the burning of coal and other solid fuel.

Fossil Fuels: Fuels such as coal, oil, and natural gas; so-called because they are the remains of ancient plant and animal life.

Fugitive Dust: Dust particles that are introduced into the air through certain activities such as soil cultivation, or vehicles operating on open fields or dirt roadways. A subset of fugitive emissions.

Fugitive Emissions: Emissions not caught by a capture system which are often due to equipment leaks, evaporative processes and windblown disturbances.

Furnace: A combustion chamber; an enclosed structure in which fuel is burned to heat air or material.

FutureGen: FutureGen is a project of the US government to build a near zero-emissions coal-fueled power plant that intends to produce hydrogen and electricity while using carbon capture and storage.

Gas Turbine: An engine that uses a compressor to draw air into the engine and compress it. Fuel is added to the air and combusted in a combustor. Hot combustion gases exiting the engine turn a turbine which also turns the compressor. The engine's power output can be delivered from the compressor or turbine side of the engine.

Gasifier: A device for converting solid fuel into gaseous fuel.

Generation (Electricity): The process of producing electric energy from other forms of energy; also, the amount of electric energy produced, expressed in watthours (Wh).

Global Warming: An increase in the temperature of the Earth's troposphere. Global warming has occurred in the past as a result of natural influences, but the term is most often used to refer to the warming predicted by computer models to occur as a result of increased emissions of greenhouse gases.

GLYCALC: A software program for estimating air emissions from glycol units using triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).

Glycol dehydrator: Any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water from the natural gas stream.

Green Power: Electricity that is generated from renewable energy sources is often referred to as "green power." Green power products can include electricity generated exclusively from renewable resources or, more frequently, electricity produced from a combination of fossil and renewable resources. Also known as "blended" products, these products typically have lower prices than 100 percent renewable products. Customers who take advantage of these options usually pay a premium for having some or all of their electricity produced from renewable resources. To find out more about green power, visit EPA's Green Power Partnership Web site.

Greenhouse Effect: The warming effect of the Earth's atmosphere. Light energy from the sun which passes through the Earth's atmosphere is absorbed by the Earth's surface and re-radiated into the atmosphere as heat energy. The heat energy is then trapped by the atmosphere, creating a situation similar to that which occurs in a car with its windows rolled up. A number of scientists believe that the emission of CO_2 and other gases into the atmosphere may increase the greenhouse effect and contribute to global warming.

Greenhouse Gases: Atmospheric gases such as carbon dioxide, methane, chlorofluorocarbons, nitrous oxide, ozone, and water vapor that slow the passage of re-radiated heat through the Earth's atmosphere.

Gypsum: Gypsum is one of the most widely used minerals in the world. Most gypsum in the United States is used to make wallboard for homes, offices, and commercial buildings; a typical new American home contains more than seven metric tons of gypsum alone. Moreover, gypsum is used worldwide in concrete for highways, bridges, buildings, and many other structures that are part of our everyday life. Gypsum also is used extensively as a soil conditioner on large tracts of land in suburban areas, as well as in agricultural regions.

Hazardous Air Pollutant (HAP): An air pollutant listed under section 112 (b) of the federal Clean Air Act as particularly hazardous to health. Emission sources of hazardous air pollutants are identified by U.S. EPA, and emission standards are set accordingly.

Haze (Hazy): A phenomenon that results in reduced visibility due to the scattering of light caused by aerosols. Haze is caused in large part by man-made air pollutants.

Health-Based Standard (Primary Standard): A dosage of air pollution scientifically determined to protect against human health effects such as asthma, emphysema, and cancer.

Heat Recovery Steam Generator (HRSG): Recovers waste heat exhaust from a combustion turbine and generates steam

"Hot Spot": (See toxic hot spot.)

Hydrated Lime Injection: Calcium hydroxide, also known as slaked lime, is a chemical compound with the chemical formula Ca(OH)2. It is a colorless crystal or white powder, and is obtained when calcium oxide (called lime or quicklime) is slaked with water. It can also be precipitated by mixing an aqueous solution of calcium chloride and an aqueous solution of sodium hydroxide. A traditional name for calcium hydroxide is slaked lime, or hydrated lime.
Hydrated lime may be injected into the upper regions of a furnace where high temperatures are conducive to driving the reaction between the calcium and SO2 to achieve up to 70% SO2 removal.

Hydrocarbons: Compounds containing various combinations of hydrogen and carbon atoms. They may be emitted into the air by natural sources (e.g., trees) and as a result of fossil and vegetative fuel combustion, fuel volatilization, and solvent use. Hydrocarbons are a major contributor to smog.

Hydrogen Sulfide (H_2S): A colorless, flammable, poisonous compound having a characteristic rotten-egg odor. It is used in industrial processes and may be emitted into the air.

Incentives: Subsidies and other Government actions where the Governments's financial assistance is indirect.

Incineration: The act of burning a material to ashes.

Indirect emissions: *See* Indirect Source.

Indirect Source: Any facility, building, structure, or installation, or combination thereof, which generates or attracts mobile source activity that results in emissions of any pollutant (or precursor) for which there is a state ambient air quality standard. Examples of indirect sources include employment sites, shopping centers, sports facilities, housing developments, airports, commercial and industrial development, and parking lots and garages.

Industrial Source: Any of a large number of sources -- such as manufacturing operations, oil and gas refineries, food processing plants, and energy generating facilities -- that emit substances into the atmosphere.

Inert Gas: A gas that does not react with the substances coming in contact with it.

Inert gas blanket: "Blanket" of inert (chemically non-reactive) gas that fills the space above the condensate/crude oil to minimize volatilization and vapor loss.

Injection wells: Well in which fluids are injected rather than produced, the primary objective typically being to maintain reservoir pressure. Two common types of injection gas and water. Separated gas from production wells or possibly imported gas may be reinjected into the upper gas section of the reservoir to maintain pressure.

Inspection and Maintenance (I&M) Program: A motor vehicle inspection program. The purpose of the I&M is to reduce emissions by assuring that cars are running properly. It is designed to identify vehicles in need of maintenance and to assure the effectiveness of their emission control systems on a biennial basis.

Integrated Sampling Device: An air sampling device that allows estimation of air quality components over a period of time through laboratory analysis of the sampler's medium.

Internal Combustion Engine: An engine in which both the heat energy and the ensuing mechanical energy are produced inside the engine. Includes gas turbines, spark ignition gas, and compression ignition diesel engines.

Inversion: A layer of warm air in the atmosphere that prevents the rise of cooling air and traps pollutants beneath it.

Kilowatt (kW): One thousand watts of electricity (See Watt).

Kilowatthour (kWh): One thousand watthours.

Kimray pump: Brand name of automated glycol pump used to circulate glycol in dehydrators.

Laser ignition: Ignition sequence replacing the conventional spark plugs with a laser beam that is focused to a point in the combustion chamber. There, the focused, coherent light ionizes the fuel-air mixture to initiate combustion.

Lead: A gray-white metal that is soft, malleable, ductile, and resistant to corrosion. Sources of lead resulting in concentrations in the air include industrial sources and crustal weathering of soils followed by fugitive dust emissions. Health effects from exposure to lead include brain and kidney damage and learning disabilities. Lead is the only substance which is currently listed as both a criteria air pollutant and a toxic air contaminant.

Leadership in Energy Efficiency and Design certification (LEED): The Leadership in Energy and Environmental Design (LEED) Green Building Rating System™ is the nationally accepted benchmark for the design, construction, and operation of high performance green buildings. LEED gives building owners and operators the tools they need to have an immediate and measurable impact on their buildings' performance. LEED promotes a whole-building approach to sustainability by recognizing performance in five key areas of human and environmental health: sustainable site development, water savings, energy efficiency, materials selection, and indoor environmental quality.

Leak Detection and Repair (LDAR): Leak detection protocol, using either Photo-ionization detectors or infrared cameras promises to prevent volatile organic compound and hazardous air pollutant emissions from leaking equipment.

Lean Burn Engine: An engine that employs a fuel mixture with a higher air content than fuel as regulated by the AFRC with a normal exhaust oxygen concentration of 2% by volume, or greater.

Liquid Natural Gas (LNG): Natural gas that has been processed to remove either valuable components (e.g. helium) or those impurities that could cause difficulty downstream (e.g. water and heavy hydrocarbons) and then condensed into a liquid.

Lowest Achievable Emission Rate (LAER): Under the Clean Air Act, the rate of emissions that reflects (1) the most stringent emission limitation in the State Implementation Plan of any state for a given source unless the owner or operator demonstrates such limitations are not achievable; or (2) the most stringent emissions limitation achieved in practice, whichever is more stringent.

Low NOx Burners: One of several combustion technologies used to reduce emissions of nitrogen oxides.

Major Source: A stationary facility that emits a regulated pollutant in an amount exceeding the threshold level depending on the location of the facility and attainment with regard to air quality status. (See Source.)

Mass Spectrometry: Analytical technique used to measure the mass-to-charge ratio of ions.

Maximum Achievable Control Technology (MACT): Federal emissions limitations based on the best demonstrated control technology or practices in similar sources to be applied to major sources emitting one or more federal hazardous air pollutants.

Mean: Average.

Median: The middle value in a population distribution, above and below which lie an equal number of individual values; midpoint.

Megawatt (MW): One million watts of electricity (See Watt).

Melting Point: The temperature at which a solid becomes a liquid. At this temperature, the solid and the liquid have the same vapor pressure.

Mercury: A chemical element in the periodic table that has the symbol Hg. A heavy, silvery transition metal, mercury is one of five elements that are liquid at or near room temperature and pressure.

Mercury Deposition Network (MDN): The objective of the MDN is to develop a national database of weekly concentrations of total mercury in precipitation and the seasonal and annual flux of total mercury in wet deposition. The data will be used to develop information on spatial and seasonal trends in mercury deposited to surface waters, forested watersheds, and other sensitive receptors. See http://nadp.sws.uiuc.edu/mdn/

Mercury (Hg) Speciation: Mercury can assume many forms and, through interactions with the environment, can be transformed into a variety of structures. The most commonly known forms of mercury include: Elemental Mercury, divalent mercury (mercuric chloride) and methyl mercury.
The behavior of mercury in the atmosphere depends upon its form, or specie. Elemental mercury (Hgo) is typically not very reactive with global lifetime of a few months to a year and is thought to be transported significantly in the troposphere. Reactive gaseous mercury (RGM) species, are not well characterized chemically but are thought to be gaseous Hg(II)-bearing molecules such as HgCl2(g). RGM species are notable for being quickly deposited from the atmosphere to the surface and are thought to be readily available for conversion to methylmercury, a highly toxic form of mercury. Particulate mercury (Hg-P) is also quickly deposited and is often found in high concentrations near combustion sources. Although much lower in proportion than Hgo, the greater reactivity and deposition rates of RGM and Hg-P make them a larger environment concern. Chemical reactions that occur in the atmosphere can transform mercury between these various species.

Mesosphere: The layer of the Earth's atmosphere above the stratosphere and below the thermosphere. It is between 35 and 60 miles from the Earth.

Methane: A chemical compound with the molecular formula CH_4. It is the simplest alkane, and the principal component of natural gas. Burning one molecule of methane in the presence of oxygen releases one molecule of CO_2 (carbon dioxide) and two molecules of H_2O. It is also an important source of hydrogen in various industrial processes. Methane is a greenhouse gas.

Methyl Mercury: Mercury in the air eventually settles into water or onto land where it can be washed into water. Once deposited, certain microorganisms can change it into methylmercury, a highly toxic form that builds up in fish, shellfish and animals that eat fish. Fish and shellfish are the main sources of methylmercury exposure to humans. Methylmercury builds up more in some types of fish and shellfish than others. The levels of methylmercury in fish and shellfish depend on what they eat, how long they live and how high they are in the food chain. Mercury exposure at high levels can harm the brain, heart, kidneys, lungs, and immune system of people of all ages. Research shows that most people's fish consumption does not cause a health concern. However, it has been demonstrated that high levels of methylmercury in the bloodstream of unborn babies and young children may harm the developing nervous system, making the child less able to think and learn.

Minor Source: Any stationary source that does not qualify as a major source and directly emits, or has the potential to emit, less than one hundred tons per year or more of any air pollutant.

Mobile Sources: Sources of air pollution such as automobiles, motorcycles, trucks, off-road vehicles, boats, and airplanes. (See also stationary sources).

Monitoring: The periodic or continuous sampling and analysis of air pollutants in ambient air or from individual pollution sources.

National Ambient Air Quality Standards (NAAQS): Standards established by the United States EPA that apply for outdoor air throughout the country. There are two types of NAAQS. Primary standards set limits to protect public health and secondary standards set limits to protect public welfare.

National Emission Standards for Hazardous Air Pollutants (NESHAPS): Emissions standards set by the U.S. EPA for a hazardous air pollutant, such as benzene, which may cause an increase in deaths or in serious, irreversible, or incapacitating illness.

Natural Sources: Non-manmade emission sources, including biological and geological sources, wildfires, and windblown dust.

Net Metering: Arrangement that permits a facility (using a meter that reads inflows and outflows of electricity) to sell any excess power it generates over its load requirement back to the electrical grid to offset consumption.

Neurotoxin: A toxin that acts specifically on nerve cells.

New Mexico Public Regulation Commission: The New Mexico Public Regulation Commission (PRC) regulates the utilities, telecommunications, motor carriers and insurance industries to ensure fair and reasonable rates, and to assure reasonable and adequate services to the public as provided by law.

New Source Performance Standards (NSPS): Uniform national EPA air emission standards that limit the amount of pollution allowed from new sources or from modified existing sources.

New Source Review (NSR): A Clean Air Act requirement that State Implementation Plans must include a permit review, which applies to the construction and operation of new and modified stationary sources in nonattainment areas, to ensure attainment of national ambient air quality standards. The two major requirements of NSR are Best Available Control Technology and Emission Offsets.

Nitrate (NO_3): A salt of nitric acid with an ion composed of one nitrogen and three oxygen atoms.

Nitric Oxide (NO): Precursor of ozone, NO_2, and nitrate; nitric oxide is usually emitted from combustion processes. Nitric oxide is converted to nitrogen dioxide (NO_2) in the atmosphere, and then becomes involved in the photochemical processes and / or particulate formation. (See Nitrogen Oxides.)

Nitrogen: Chemical element, which has the symbol N, and atomic number 7. Elemental nitrogen is a colorless, odorless, tasteless and mostly inert diatomic gas at standard conditions, constituting 78.1% by volume of Earth's atmosphere.

Nitrogen Enrichment Mode: NOx decreases while particulate emissions increase.

Nitrogen Oxides (Oxides of Nitrogen, NOx): A general term pertaining to compounds of nitric oxide (NO), nitrogen dioxide (NO_2) and other oxides of nitrogen. Nitrogen oxides are typically created during combustion processes, and are major contributors to smog formation and acid deposition. NO_2 is a criteria air pollutant, and may result in numerous adverse health effects.

Nonattainment Area: A geographic area identified by the U.S. EPA as not meeting the NAAQS for a given pollutant.

Noncarcinogenic Effects: Non-cancer health effects which may include birth defects, organ damage, morbidity, and death.

Non-Industrial Source: Any of a large number of sources -- such as mobile, area-wide, indirect, and natural sources -- which emit substances into the atmosphere.

Non-Methane Hydrocarbon (NMHC): The sum of all hydrocarbon air pollutants except methane. NMHCs are significant precursors to ozone formation.

Non-Methane Organic Gas (NMOG): The sum of non-methane hydrocarbons and other organic gases such as aldehydes, ketones and ethers.

Non-Point Sources: Diffuse pollution sources that are not recognized to have a single point of origin.

Non-Road Emissions: Pollutants emitted by a variety of non-road sources such as farm and construction equipment, gasoline-powered lawn and garden equipment, and power boats and outboard motors.

NOx Traps: Operate in a two-step cyclic process. In the first stage the NOx trap adsorbs NOx while the engine operates in a lean-burn mode. In the second stage, the engine operates with excess fuel in the exhaust. The fuel decomposes on the catalyst and reduces the NOx to molecular nitrogen and water.

O_2 enrichment mode: Produces a dramatic reduction in particulate emissions at the expense of increased NOx emissions.

Opacity: The amount of light obscured by particle pollution in the atmosphere. Opacity is used as an indicator of changes in performance of particulate control systems.

Organic Compounds: A large group of chemical compounds containing mainly carbon, hydrogen, nitrogen, and oxygen. All living organisms are made up of organic compounds.

Oxidant: A substance that brings about oxidation in other substances. Oxidizing agents (oxidants) contain atoms that have suffered electron loss. In oxidizing other substances, these atoms gain electrons. Ozone, which is a primary component of smog, is an example of an oxidant.

Oxidation: The chemical reaction of a substance with oxygen or a reaction in which the atoms in an element lose electrons and its valence is correspondingly increased.

Oxidation catalysts: Element using a catalytic conversion for control of hydrocarbon and CO emissions.

Oxygenate: An organic molecule that contains oxygen. Oxygenates are typically ethers and alcohols.

Ozone (O_3): A strong smelling, pale blue, reactive toxic chemical gas consisting of three oxygen atoms. It is a product of the photochemical process involving the sun's energy and ozone precursors, such as hydrocarbons and oxides of nitrogen. Ozone exists in the upper atmosphere ozone layer (stratospheric ozone) as well as at the Earth's surface in the troposphere (ozone). Ozone in the troposphere causes numerous adverse health effects and is a criteria air pollutant. It is a major component of smog.

Ozone Depletion: The reduction in the stratospheric ozone layer. Stratospheric ozone shields the Earth from ultraviolet radiation. The breakdown of certain chlorine and / or bromine-containing compounds that catalytically destroy ozone molecules in the stratosphere can cause a reduction in the ozone layer.

Ozone-Forming Potential: (See Reactivity.)

Ozone Layer: A layer of ozone in the lower portion of the stratosphere -- 12 to 15 miles above the Earth's surface -- which helps to filter out harmful ultraviolet rays from the sun. It may be contrasted with the ozone component of photochemical smog near the Earth's surface which is harmful.

Ozone Precursors: Chemicals such as volatile organic compounds and oxides of nitrogen, occurring either naturally or as a result of human activities, which contribute to the formation of ozone, a major component of smog.

Particulate Matter (PM): Any material, except pure water, that exists in the solid or liquid state in the atmosphere. The size of particulate matter can vary from coarse, wind-blown dust particles to fine particle combustion products.

Passive Solar: A system in which solar energy alone is used for the transfer of thermal energy. Pumps, blowers, or other heat transfer devices that use energy other than solar are not used.

Permit: Written authorization from a government agency that allows for the construction and / or operation of an emissions generating facility or its equipment within certain specified limits.

Persistence: Refers to the length of time a compound stays in the atmosphere, once introduced. A compound may persist for less than a second or indefinitely.

Photovoltaic (PV) Module: An integrated assembly of interconnected photovoltaic cells designed to deliver a selected level of working voltage and current at its output terminals, packaged for protection against environment degradation, and suited for incorporation in photovoltaic power systems.

Pilot scale: Size of a system between the small laboratory scale (bench-scale) and full-size system.

Plant Pathology: The scientific study of plant diseases caused by pathogens (infectious diseases) and environmental conditons (physiological factors).

Plume: A visible or measurable discharge of a contaminant from a given point of origin that can be measured according to the Ringelmann scale. (See Ringelmann Chart.)

Plunger Lift System: Use gas pressure buildup in a well to lift a column of accumulated fluid out of the well. The plunger lift system helps to maintain gas production and may reduce the need for other remedial operations.

$PM_{2.5}$: Includes tiny particles with an aerodynamic diameter less than or equal to a nominal 2.5 microns. This fraction of particulate matter penetrates most deeply into the lungs.

PM_{10} (Particulate Matter): A criteria air pollutant consisting of small particles with an aerodynamic diameter less than or equal to a nominal 10 microns (about 1/7th the diameter of a single human hair). Their small size allows them to make their way to the air sacs deep within the lungs where they may be deposited and result in adverse health effects. PM_{10} also causes visibility reduction.

Pneumatic controls: Control systems using either compressed gas or air.

Point Sources: Specific points of origin where pollutants are emitted into the atmosphere such as factory smokestacks. (See also Area-Wide Sources and Fugitive Emissions.)

Polycyclic Aromatic Hydrocarbons (PAHs): Organic compounds which include only carbon and hydrogen with a fused ring structure containing at least two benzene (six-sided) rings. PAHs may also contain additional fused rings that are not six-sided. The combustion of organic substances is a common source of atmospheric PAHs.

Polymer: Natural or synthetic chemical compounds composed of up to millions of repeated linked units, each of a relatively light and simple molecule.

Pounds per million BTU (lb/mmBtu): A measure of the mass (of a pollutant) emitted for each million British thermal units (Btu) of energy fed to a combustion source. A BTU is defined as the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Precipitator: Pollution control device that collects particles from an air stream. (See Electrostatic Precipitator.)

Prescribed Burning: The planned application of fire to vegetation to achieve any specific objective on lands selected in advance of that application.

Prevention of Significant Deterioration (PSD): A permitting program for new and modified stationary sources of air pollution located in an area that attains or is unclassified for national ambient air quality standards (NAAQS). The PSD program is designed to ensure that air quality does not degrade beyond those air quality standards or beyond specified incremental amounts. The PSD permitting process requires new and modified facilities above a specified size threshold to be carefully reviewed prior to construction for air quality impacts. PSD also requires those facilities to apply BACT to minimize emissions of air pollutants. A public notification process is conducted prior to issuance of final PSD permits.

Primary Particles: Particles that are directly emitted from combustion and fugitive dust sources. (Compare with Secondary Particle.)

Produced water: Water extracted from the subsurface with oil and gas. It may include water from the reservoir, water that has been injected into the formation, and any chemicals added during the production/treatment process.

Production Tax Credit (PTC): an inflation - adjusted 1.5 cents per kilowatthour payment for electricity produced using qualifying renewable energy sources.

Programmic logic controller (PLC): Control software for engine mapping / reactant injection requirements used to control the SCR system.

Public Utility Regulatory Policies Act of 1978 (PURPA): One part of the National Energy Act, PURPA contains measures designed to encourage the conservation of energy, more efficient use of resources, and equitable rates. Principal among these were suggested retail rate reforms and new incentives for production of electricity by cogenerators and users of renewable resources.

Pulverized coal: is a coal that has been crushed to a fine dust in a grinding mill. It is blown into the combustion zone of a furnace and burns very rapidly.

Radionuclides: Atoms with an unstable nucleus, characterized by excess energy which is available to be imparted either to a newly-created radiation particle within the nucleus, or else to an atomic electron.

Reactive Organic Gas (ROG): A photochemically reactive chemical gas, composed of non-methane hydrocarbons, that may contribute to the formation of smog. Also sometimes referred to as Non-Methane Organic Gases (NMOGs). (See also Volatile Organic Compounds and Hydrocarbons.)

Reactivity (or Hydrocarbon Photochemical Reactivity): A term used in the context of air quality management to describe a hydrocarbon's ability to react (participate in photochemical reactions) to form ozone in the atmosphere. Different hydrocarbons react at different rates. The more reactive a hydrocarbon, the greater potential it has to form ozone.

Reasonably Available Control Measures (RACM): A broadly defined term referring to technologies and other measures that can be used to control pollution. They include Reasonably Available Control Technology and other measures. In the case of PM_{10}, RACM refers to approaches for controlling small or dispersed source categories such as road dust, woodstoves, and open burning.

Reasonably Available Control Technology (RACT): Control techniques defined in U.S. EPA guidelines for limiting emissions from existing sources in nonattainment areas. RACTs are adopted and implemented by states.

Reciprocating Internal Combustion Engine (RICE): An engine in which air and fuel are introduced into cylinders, compressed by pistons and ignited by a spark plug or by compression. Combustion in the cylinders pushes the pistons sequentially, transferring energy to the crankshaft, causing it to rotate.

Refraction: The change in direction of a light wave due to a change in its speed when it passes from one medium to another.

Regional Haze: The haze produced by a multitude of sources and activities which emit fine particles and their precursors across a broad geographic area. National regulations require states to develop plans to reduce the regional haze that impairs visibility in national parks and wilderness areas.

Regional Haze Rule: The Regional Haze Rule calls for state and federal agencies to work together to improve visibility in 156 national parks and wilderness areas such as the Grand Canyon, Yosemite, the Great Smokies and Shenandoah.
The rule requires the states, in coordination with the Environmental Protection Agency, the National Park Service, U.S. Fish and Wildlife Service, the U.S. Forest Service, and other interested parties, to develop and implement air quality protection plans to reduce the pollution that causes visibility impairment. The first State plans for regional haze are due in the 2003-2008 timeframe. Five multi-state regional planning organizations are working together now to develop the technical basis for these plans.

Regulatory Impact Analysis (RIA): A tool used to assess the likely effects of a proposed new regulation or regulatory change.

Reid Vapor Pressure: Refers to the vapor pressure of the fuel expressed in the nearest hundredth of a pound per square inch (psi) with a higher number reflecting more gasoline evaporation.

Renewable Energy: Renewable Energy is energy derived from resources that are regenerative or, for all practical purposes, cannot be depleted.

Renewable Energy Resources: Energy resources that are naturally replenishing but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Renewable energy resources include: biomass, hydro, geothermal, solar, wind, ocean thermal, wave action, and tidal action.

Renewable Portfolio Standard (RPS): a mandate requiring that renewable energy provide a certain percentage of total energy generation or consumption.

Retrofit or retrofitting: The addition of new technology or features to older systems.

Rich Burn Engine: Any four-stroke spark ignited engine with a manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NOx (such as pre-combustion chambers) will be considered lean burn engines. Existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Ringelmann Chart: A series of charts, numbered 0 to 5, that simulate various smoke densities by presenting different percentages of black. A Ringelmann No. 1 is equivalent to 20 percent black; a Ringelmann No. 5 is 100 percent black. They are used for measuring the opacity or equivalent obscuration of smoke arising from stacks and other sources by matching the actual effluent with the various numbers, or densities, indicated by the charts.

Risk Assessment: An evaluation of risk which estimates the relationship between exposure to a harmful substance and the likelihood that harm will result from that exposure.

Risk Management: An evaluation of the need for and feasibility of reducing risk. It includes consideration of magnitude of risk, available control technologies, and economic feasibility.

Risk Management Plan (RMP): A document prepared by a project manager to foresee risks, estimate effectiveness, and to create response plans to mitigate them.

Sanctions: Actions taken against a state or local government by the federal government for failure to plan or to implement a State Implementation Plan (SIP). Examples include withholding of highway funds and a ban on construction of new sources of potential pollution.

Scrubber: An air pollution control device that uses a high energy liquid spray to remove aerosol and gaseous pollutants from an air stream. The gases are removed either by absorption or chemical reaction.

Secondary Particle: Particles that are formed in the atmosphere. Secondary particles are products of the chemical reactions between gases, such as nitrates, sulfur oxides, ammonia, and organic products.

Selective Catalytic Reduction (SCR) or selective non-catalytic reduction (SNCR): Selective catalytic reduction means a noncombustion control technology that destroys NOx by injecting a reducing agent (e.g., ammonia) into the flue gas that, in the presence of a catalyst (e.g., vanadium, titanium, or zeolite), converts NOx into molecular nitrogen and water.

Selexol: Selexol is the trade name for a physical solvent that is a mixture dimethyl ethers of polyethylene glycol. In the Selexol process, the solvent dissolves the CO_2 from the gas stream at a relatively high pressure, generally in the range of 300 – 1,000 psia. The resulting rich solvent can then either be let down in pressure and/or steam stripped to release and recover the CO_2.

Sensitive Groups: Identifiable subsets of the general population that are at greater risk than the general population to the toxic effects of a specific air pollutant (e.g., infants, asthmatics, elderly).

Sequestration: Capture and long term storage of carbon. See also Carbon Capture and Storage

Smog: A combination of smoke and other particulates, ozone, hydrocarbons, nitrogen oxides, and other chemically reactive compounds which, under certain conditions of weather and sunlight, may result in a murky brown haze that causes adverse health effects.

Smoke: A form of air pollution consisting primarily of particulate matter (i.e., particles released by combustion). Other components of smoke include gaseous air pollutants such as hydrocarbons, oxides of nitrogen, and carbon monoxide. Sources of smoke may include fossil fuel combustion, prescribed and agricultural burning, and other combustion processes.

Solar Energy: The radiant energy of the sun, which can be converted into other forms of energy, such as heat or electricity.

Solar Thermal Collector: A device designed to receive solar radiation and convert it into thermal energy. Normally, a solar thermal collector includes a frame, glazing, and an absorber, together with the appropriate insulation. The heat collected by the solar thermal collector may be used immediately or stored for later use. Solar Thermal Collector, Special: An evacuated tube collector or a concentrating (focusing) collector. Special collectors operate in the temperature (low concentration for pool heating) to several hundred degrees Fahrenheit (high concentration for air conditioning and specialized industrial processes).

Soot: Very fine carbon particles that have a black appearance when emitted into the air.

Source: Any place or object from which air pollutants are released. Sources that are fixed in space are stationary sources and sources that move are mobile sources.

Spark ignition (SI): Ignition of combustion within an engine using spark plugs with a high-intensity spark of timed duration to ignite a compressed fuel-air mixture within the cylinder. SI engines are available in sizes up to 5 MW. Natural gas is the preferred fuel in electric generation and CHP applications of SI.

Stack Gas Bypass: The practice of routing some portion of exhaust gas, often from a large boiler, around the pollution control equipment, and into the exhaust stack. This is usually done to introduce hot, unscrubbed, gas into the stack to mix with and raise the temperature of the cool, scrubbed gas above its acid dew point and/or to increase plume buoyancy and dispersion. If the gas cools to its acid dew point, acid mists and droplets may fall out near the stack, or corrode unprotected stack linings.

State Implementation Plan (SIP): The group of plans and regulations submitted by a state to the U.S. EPA for implementation of the federal Clean Air Act.

Stationary Sources: Non-mobile sources such as power plants, refineries, and manufacturing facilities which emit air pollutants. (See also mobile sources).

Still vent column: Emission point for regeneration of glycol streams, resulting in vapors of water, VOC and HAPs.

Stoichiometric engine: An engine with the chemically correct proportion of fuel to air in the combustion chamber during combustion.

Storage Tank: Any stationary container, reservoir, or tank, used for storage of liquids.

Stratosphere: The layer of the Earth's atmosphere above the troposphere and below the mesosphere. It extends between 10 and 30 miles above the Earth's surface and contains the ozone layer in its lower portion. The stratospheric layer mixes relatively slowly; pollutants that enter it may remain for long periods of time.

Subsidy: Financial assistance granted by the Government to firms and individuals.

Sulfur Dioxide (SO_2): A strong smelling, colorless gas that is formed by the combustion of fossil fuels. Power plants, which may use coal or oil high in sulfur content, can be major sources of SO_2. SO_2 and other sulfur oxides contribute to the problem of acid deposition. SO_2 is a criteria air pollutant.

Sulfur Oxides (SOx): Pungent, colorless gases (sulfates are solids) formed primarily by the combustion of sulfur-containing fossil fuels, especially coal and oil. Considered major air pollutants, sulfur oxides may impact human health and damage vegetation.

Syngas: Syngas is the gas product resulting from gasification processes and can be used as a fuel to drive power generation or a feedstock for chemical synthesis.

Tailpipe emissions: Products of burning fuel in the vehicle's engine emitted from the vehicle's exhaust system.

Thief hatch: Opening in the top of the stock tank that allows tank access to the interior of the tank for withdrawal or measurement of fluid.

Title V: A section of the 1990 amendments to the federal Clean Air Act that requires a federally enforceable operating permit for major sources of air pollution.

Topography: The configuration of a surface, especially the Earth's surface, including its relief and the position of its natural and man-made features.

Total dissolved solids (TDS): The combined content of all inorganic and organic substances contained in a liquid which are present in a molecular, ionized or micro-granular (colloidal sol) suspended form.

Total Suspended Particulate (TSP): Particles of solid or liquid matter -- such as soot, dust, aerosols, fumes, and mist -- up to approximately 30 microns in size.

Toxic Hot Spot: A location where emissions from specific sources may expose individuals and population groups to elevated risks of adverse health effects -- including but not limited to cancer -- and contribute to the cumulative health risks of emissions from other sources in the area.

Trading Credits: The basic concept of a cap and trade system is that the government turns a certain quantity of emissions into a marketable commodity, called a credit, which is then allowed to be bought and sold freely on the market. See http://www.epa.gov/airmarkets/trading/basics.html

Transmission System (Electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

Triethylene glycol (TEG) dehydrator: Any device in which a liquid glycol (including, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.

Troposphere: The layer of the Earth's atmosphere nearest to the surface of the Earth. The troposphere extends outward about five miles at the poles and about 10 miles at the equator.

Turbine: A machine for generating rotary mechanical power from the energy of a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction, or a mixture of the two.

Underground Storage Tank (UST): Refers to tanks used to store gasoline underground.

United States Environmental Protection Agency (U.S. EPA): The federal agency charged with setting policy and guidelines, and carrying out legal mandates for the protection of national interests in environmental resources.

Urea: An organic compound of carbon, nitrogen, oxygen and hydrogen, with the formula CON_2H_4 or (NH_2) CO_2 or CN_2H_4O. Used as a catalyst for SCR applications.

Vanadium: A chemical element in the periodic table that has the symbol V and atomic number 23. A rare, soft and ductile element, vanadium is found combined in certain minerals and is used mainly to produce certain alloys.

Vapor recovery unit (VRU): A system composed of a scrubber, a compressor and a switch. Its main purpose is to recover vapors formed inside completely sealed crude oil or condensate tanks.

Vehicle Miles Traveled (VMT): The miles traveled by motor vehicles over a specified length of time (e.g., daily, monthly or yearly) or over a specified road or transportation corridor.

Visibility: A measurement of the ability to see and identify objects at different distances. Visibility reduction from air pollution is often due to the presence of sulfur and nitrogen oxides, as well as particulate matter.

Visibility Reducing Particles (VRP): Any particles in the atmosphere that obstruct the range of visibility.

Volatile: Any substance that evaporates readily.

Volatile Organic Compounds (VOCs): Carbon-containing compounds that evaporate into the air (with a few exceptions). VOCs contribute to the formation of smog and / or may themselves be toxic. VOCs often have an odor, and some examples include gasoline, alcohol, and the solvents used in paints.

Watt (Electric): The electrical unit of power. The rate of energy transfer equivalent to 1 ampere of electric current flowing under a pressure of 1 volt at unity power factor.

Watthour (Wh): The electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Weight of Evidence: The extent to which the available information supports the hypothesis that a substance causes an effect in humans. For example, factors which determine the weight-of-evidence that a chemical poses a hazard to humans include the number of tissue sites affected by the agent; the number of animal species, strains, sexes, relationship, statistical significance in the occurrence of the adverse effect in treated subjects compared to untreated controls; and the timing of the occurrence of adverse effect.

Welfare-Based Standard (Secondary Standard): An air quality standard that prevents, reduces, or minimizes injury to agricultural crops and livestock, damage to and the deterioration of property, and hazards to air and ground transportation.

Wet Flue Gas Desulfurization (FGD): In wet scrubbers, the flue gas enters a large vessel (spray tower or absorber), where it is sprayed with water slurry (approximately ten percent lime or limestone). The calcium in the slurry reacts with the SO2 to form calcium sulfite or calcium sulfate. A portion of the slurry from the reaction tank is pumped into the thickener, where the solids settle before going to a filter for final dewatering to about 50 percent solids. The calcium sulfite waste product is usually mixed with fly ash (approximately 1:1) and fixative lime (approximately five percent) and disposed of in landfills. Alternatively, gypsum can be produced from FGD waste, which is a useful by-product.

Wind Energy: Energy present in wind motion that can be converted to mechanical energy for driving pumps, mills, and electric power generators. Wind pushes against sails, vanes, or blades radiating from a central rotating shaft.

Woodburning Pollution: Air pollution caused by woodburning stoves and fireplaces that emit particulate matter, carbon monoxide and odorous and toxic substances.

Zeolite: Minerals that have a micro-porous structure.

Zero Emissions Dehydrator: A Zero Emissions Dehydrator combines several technologies that lower emissions. These technologies eliminate emissions from glycol circulation pumps, gas strippers and the majority of the still column effluent. Rather than being released as vapor, the water and hydrocarbons are collected from the glycol still column, and the condensable and non-condensable components are separated from each other. The two primary condensable products are wastewater, which can be disposed of with treatment; and hydrocarbon condensate, which can be sold. The non-condensable products (methane and ethane) are used as fuel for the glycol reboiler instead of venting to the atmosphere.

Table of Mitigation Options Not Written with Rationale

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SECTION	MITIGATION OPTION TITLE	RATIONALE FOR NOT WRITING
Oil and Gas: Stationary RICE (Small and large engines)	Emission limit on existing engines (1g/hp hr and 2g/hp hr)	Will incorporate this into the NSPS mitigation option and note that it will apply to existing engines.
	Replacing ignition systems to decrease false starts	This option is generally covered in the Operation and Maintenance mitigation option
	Replace piston rod packing (pumps)	This will be added to the Operation and Maintenance mitigation option.
	Minimize (control?) engine blow downs	This is already a common industry practice and has been deleted as an option
	Utilize exhaust gas analyzers to adjust AFR	This was included in the Oxidation Catalysts and AFRC on Lean Burn Engines option.
	Smart AFRC (air-fuel-ratio-controller)	Included in the other AFRC options
	Replace gas engine starters with electric air compressors	Negligible emissions reductions for applying this option.
	Provide training for field personnel on engine maintenance with regard to AQ considerations	Incorporated into Option titled “Adherence to Manufacturers’ Operation and Maintenance Requirements”
Oil and Gas: Mobile and Non-Road		
Oil and Gas: Rig Engines	Analysis of all drill rigs – replace the dirtiest 20%	Will reference in Tier 2-4 Mitigation Option Development, but also move to overarching discussion to determine the priority on rig engine reductions
	Electric Powered Drill Rig	Not selected due to low feasibility around availability of electricity
Oil and Gas: Turbines		
Oil and Gas: Exploration & Production (Tanks)	Mufflers	Does not apply to Air Quality.
	Centralized Collection for Existing Sources	This option is not feasible for retrofit application in the San Juan Basin

SECTION	MITIGATION OPTION TITLE	RATIONALE FOR NOT WRITING
Oil and Gas: Exploration & Production (Dehydrators/Separators/ Heaters)	Centralized Dehydrators	Already or will be incorporated in other papers on centralization
	Optimization and automation	Incorporated into the Option under Stationary RICE subsection.
	Low/Ultra low NOx burners	Application not appropriate for the San Juan Basin, because most burners commonly used in the Four Corners Area smaller than the technology is capable of providing emission reduction.
	Install VRU	Principle of the option as applied is explained in the Option titled “Install VRU” under subsection for E&P Tanks.
	Centralized Dehydrators	Principle of the option is incorporated into the Option under Stationary RICE. Additionally, the San Juan Basin does not have a high need for wellhead dehydration.
Oil and Gas: E&P Pneumatics/ Controllers/ Fugitives	Directed inspection and maintenance program	Addressed by Option title “Specific Direction for How to Meet NSPS and MACT Standards: Directed Inspection and Maintenance” in Midstream section.
Oil and Gas: Midstream Operations	Install Flares	Never submitted.
Oil and Gas: Overarching Issues		
Power Plants: Future	Integrated Gasification Combined Cycle (IGCC) Political Aspects and Incentives	Combined with Integrated Gasification Combined Cycle (IGCC) Technical Aspects and listed as mitigation option “Integrated Gasification Combined Cycle (IGCC)”
Power Plants: Overarching	Four Corners Area Mercury Studies	Combined with Participate and Support Mercury Deposition Studies
Other Sources:	Apply Uniform Regulations Between Jurisdictions for Dust Control	Never submitted.
	Fugitive Dust Road Mitigation Plan	See option papers on oil & gas road dust mitigation.
	Include Multi-Modal Transportation Options in 2035 Transportation Plan	Scope of this option is very large. A proposal was submitted to DOE.
	Pursue Clean Cities Designation for Western Slope	This was not awarded by DOE. Not clear just who would house and how funding could be sustainable.
	Auto Licensing or Registration Additional Tax	Group determined this was unlikely to be economically feasible at this time.
	Oil and Gas Fleet Retrofit / Replacement	Numerous options were written as part of the oil & gas section dealing with vehicles.

SECTION	MITIGATION OPTION TITLE	RATIONALE FOR NOT WRITING
Other Sources:	Consider Ambient Air Quality Before Burning Prescribed Fire	Never submitted.
	Develop Controls on Agricultural Burning in Colorado	Never submitted.
Energy Efficiency, Renewable Energy, Conservation	Corporate Rebate/incentives for Energy Efficiency	Combined with Building Standards for Increased Commercial and Residential Energy Efficiency (EE)
	Pilot Neighborhood project to Change Behavior to Reduce Energy Use – Increase Efficiency	Combined with Audits of Low Income Areas to find Simple Solutions
	Solar/PV Applications	Never submitted.
	Optimization of Compression	Incorporated into the Option under Stationary RICE subsection titled "Optimization and automation and Centralized Collection for New Sources"
	Micro Turbines	Incorporated into Option titled "Cogeneration/Combined Heat and Power"
	Product Capture/Maximize Efficiency	Never submitted.
	Multi-Phase Pipeline	Never submitted.
	Comprehensive Impacts of efficiency	Never submitted.
	Efficiency/Conservation on individual level	Never submitted.
	Sustainable business practices	Never submitted.
	Zero Waste	Never submitted.

GENERAL: PUBLIC COMMENTS

General Public Comments

Comment
Air quality in the Four Corners Area has been studied and cussed and discussed for several decades while the pollution problems grow and grow. We sincerely hope that measurable benefits to our environment will be the product of this massive piece of work by the Four Corners Air Quality Task Force. Polluting industries and enforcement agencies cannot continue to "turn their backs" on what IS happening to the quality of our air. It is our right to breathe clean air. We all know that San Juan County has serious air quality issues. San Juan County is ranked in the top 10% of worst counties in the United States for toxic releases to the environment according to Scorecard, a pollution information web site. These toxic releases include volatile organic compound emissions from oil and gas facilities, and power plant emissions such as particulate matter (PM) and sulfur dioxide. Many other toxic emissions are listed. All of these pollutants are threats to human health, the land and water. Enough is Enough! Now is the time to take action to clean up our environment! Regulatory agencies need to begin much stronger enforcement of current regulations and work toward more stringent regulations. Further degradation of our environment is not acceptable. State cancer profiles show that this area has the highest rate of cancer in New Mexico. Respiratory disease is high in the Four Corners Area. A comprehensive health study for the entire Four Corners Area would most likely reveal even more alarming health problems among our population. Clean up of area coal fired power plants and mandatory emissions controls and clean up of oil and gas facilities are necessary for the health and well being of the people. Health is wealth.
I've not read all the details of the report but I think there seems to be something missing. I don't see any analysis of the future demand on this area in terms of energy. There is a fast growing school of thought that indicates coal can provide the energy bridge the United States needs to exit the Middle East. I think people need to understand that the coal resources here in the San Juan Basin could become a big part of a new energy strategy for transportation. Electric cars and electric high speed trains could be used to help replace the demand for middle east oil being used now for gasoline and jet fuel. If this happens and I think it is coming in the next 10 years, what will we see here? Is any planning being done for that? If you think there is a lot of CO_2 from 3 power plants, what if there were 20? This may seem like bad news but it's not if we have a plan. For less than the cost of the Iraq war, we could install the infrastructure to convert the coal here into H_2 and CO_2. The H_2 could be used in new power plants driving engines turning generators thereby reducing the requirement for steam from water and the CO_2 could be captured and piped to Bakersfield to be injected into the heavy oils there in enhance oil recovery. The power grid will would require significant upgrades to accommodate the additional load in addition to providing ways for wind and solar power to come on the system. Instead of planning for war, let's plan for peace. This is a big effort. We need a leader with some vision at the Federal level. Is there someone who could have understood the impact of the internet and pushed to develop that infrastructure? Internet super highway -> I say Energy Super Highway!

Comment
The Southern Ute Indian Tribe Growth Fund (SUGF) appreciates the opportunity provided to the public to allow for review and comment on the Draft Four Corners Air Quality Task Force Report (Version 7); furthermore SUGF, is appreciative of the tremendous undertaking of the various resources that have come together to develop a range of possible air quality mitigation options that may remedy air quality issues in the Four Corners area. SUGF understands that this document is non-conclusive, and does not convey consensus of the various participating bodies regarding the mentioned mitigation options. It is further understood that these developed options may be considered by the various regulatory bodies to be implemented into air quality management strategies. At that time, it is recommended that public participation similar to this effort be duplicated. As you may be aware, production of natural gas is critical to the Southern Ute Indian Tribe's (Tribe) economic base and growth. The SUGF, a private investment entity of the Tribe supports development of its natural resources, yet remains cognizant of its responsibility to protect the environment. This is exemplified through Tribal processes such as conditional approval(s) of future oil and gas development that will require significant mitigation measures involving installation of control technologies on compression units. Another significant development occurring is the continual development of the Tribe's Air Quality Program, through the establishment of the Southern Ute Indian Tribe/State of Colorado Environmental Commission.
BP believes that the establishment of the Four Corners Task Force is a very useful venue for stakeholders and regulators to discuss air quality issues with the ultimate goal of managing air quality in the region. Developing strategies to measurably improve air quality requires extensive technical, engineering and policy analyses. In addition, such analyses require time and should not be influenced by arbitrary schedules. BP believes that solutions to the issues should be crafted on the basis of air quality improvement and economic efficiency. Control requirements based on a "one size solution" may not result in measurable air quality improvements nor be the most economic solution for improving air quality. BP also believes that it is important for the Task Force to focus on understanding source receptor relations in the region through modeling and analysis of existing air quality data as well as emission data.
I could not find the Federal Register notification for this superficial 'public comment' period. This process is fatally flawed as proper 'government to government meetings' have not been held. The formal notification has not been provided to all American Indian Nations and official respective American Indian Nation Tribal Council has not been officially made known. How will such federal mandates affect the sovereignty of American Indian Nations? This appears to violate basic principles of American Indian Nation Treaties as it does the Law of Nations. It appears, these federal agencies are recruiting non-profits to further international agendas for their federal acquisitions while attempting to impose hidden taxation. These federal regulatory actions certainly appear to emphasize regulation without representation as it promotes no accountability while encouraging implementation of un-ratified international conventions such as Kyoto. I attended the first meeting held in Farmington New Mexico for the Four Corners area regarding Air Quality on November 4, 2005. I spoke with a federal officer in her official capacity who acknowledged this process was indeed implementing the Kyoto Treaty that is un-ratified by U.S. Congress. She also acknowledged that the way the federal agencies were working around this un-ratified treaty was by entering into Memorandums of Understanding (MOU) between the respective State governments. These MOU's are signed by State governors as is the case with New Mexico State Governor Bill Richardson. New Mexico Governor Richardson proposed adoption of a regional climate change scheme to California Governor Arnold Schwarzenegger as stated in Executive order June 9, 2005. New Mexico Governor Richardson displays a definite conflict of interest as he continues to enjoy the pleasure of the United Nations while acting as United Nations Ambassador and more of an International Citizen, during his term as New Mexico Governor. A man cannot serve two masters anymore than he can be a citizen of two countries.

Comment
I received an email from a member of Montezuma Vision Project May 2, 2007 who wrote in reference to membership; "Most of the people are progressives who are interested in promoting planning for good quality of life." The main intent behind those who claim to be Progressives is to reduce "right" to privilege and "liberty" to servitude. Progressives enjoy collectivism implemented upon the masses while they enjoy their appointed and self anointed aristocracy oligarchy. The first U.S. Progressive Party formed in 1912 and has found its niche in liberalism and the environmental movement. There are Progressives connected to Democratic Socialist parties. Progressives believe and implement the old Roman Prodigal estate schemes promoted by IUCN (International Union for Conservation of Nature) which in reality is promoting Sustainable Development as specified in Agenda 21- 1992 Rio Summit Declaration. The Kyoto Protocol was created by an Intergovernmental Panel on Climate Change established in 1988 jointly by World Meteorological Organization and the United Nations Environment Programme. The Convention (Kyoto Protocol To The United Nations Framework Convention On Climate Change) was adopted by the Conference of the Parties meaning Parties to the Convention, May 1992, while in New York. The Montreal Protocol on Substances that Deplete the Ozone Layer was adopted by the Conference of the Parties September 1987. The federal officer while I was at November 4, 2005 meeting, acknowledged this entire process was truly implemented the Untied Nations, World Bank, IMF, Federal Reserve, and agenda for Sustainable Development which is also known as Agenda 21. The federal officer told me that there is a system in place for schemes that allow for a 'pay to pollute' program. She provided the example of power plants on the East Coast that do not have state of the art environmental equipment and cannot be fitted or converted with such state of the art environmental equipment. Certificates from power plants in Western U.S. who are newer and have up dated equipment as well as cleaner coal, would sell certificates to the Eastern U.S power plants as a means of offsetting Eastern power plant pollution. In reality, this is a pay to pollute scheme that mirrors the new-politically correct scheme of paying to have a 'Carbon Imprint or Footprint'. Example: a representative from Nature Conservancy conducts a Carbon Imprint intake of your life. The calculations are conducted on life style such as how often a person drives a car, fly's an airplanes, rides a bicycle, uses a microwave oven and so forth. Once the representative determines the Carbon Imprint number, the person is expected to pay an outrageous sum of money (Federal Reserve Notes) to an environmental non profit of his or her choice to off set the Carbon Imprint. In reality, this is extortion at its best while providing a steady source of income to environmental non profits who may not otherwise obtain such vast forms of income. It certainly appears this entire scheme is just another form of taxation forced upon the public. While I was in attendance at November 4, 2005 meeting I listened to the key-note speaker talk of new EPA standards that must be implemented. In reality, he was telling the public this unfunded and unjustified federal mandate 'must' be complied to. Meanwhile, he mentioned the Four Corners area has dust & silt particles blown in from other larger cities as far away as Phoenix and Tucson Arizona and beyond. There were a lot of charts on the walls and the mercury issue in the Four Corners was displayed as being mainly caused from the power plants that exist in the area. First of all, there is a natural occurrence of mercury in the San Juan Mountains. Second, plants are known to absorb mercury from the ground. If the plants and trees absorb this mercury from the ground and a wildfire of significant proportions occurs what is going to happen? The mercury will be released by residual ash and debris back into the ground and even into the water supply. This cycle was not demonstrated at this meeting nor is it ever discussed. This monitoring process and so called evidence collecting done in this entire process is fatally flawed while it certainly indicates fatal deficiencies in the precision in monitoring as it suggests other uncertainties.

Comment
The picture displayed upon the website depicting this proposed Four Corners Air Quality catastrophe is fatally flawed. Photographs can be easily manipulated to reflect whatever the crisis especially with today's technology. The pictures did not show what type of a day it was such as was it a cold day or a hot day? Sometimes in this area of the Four Corners depending upon what time of the morning and what moisture is in the air, visibility can be poor from the natural moisture in the air as well as wind passing through can cause dust from the ground to be in the air. The EPA expecting to regulate such natural processes in nature is absurd. The natural occurrences were not discussed at this meeting anymore than it was reflected in any of the charts or photographs. I see this entire process as in terminal as it is fatally in error. Most of all, I see federal agencies and cohorts attempting to play God while trying to control nature. This is preposterous to claim the environment that includes animals, plants and all of nature is above humans. This is perversions of natural law at its best especially when EPA claims it can control wind, dust and weather while expecting an area such as the Four Corners to keep that dust from blowing in from other areas. It is just as absurd to create this hyped up crisis just to sell certificates to pollute and extort money from the public. Cease and desist all these actions of implementing un-ratified illegal international treaties through abusing MOU's and other such agreements. Stop trying to play God while creating a crisis just to extort money from the public and expand progressivism.

The Association between Ambient Air Quality Ozone Levels and Medical Visits for Asthma in San Juan County

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Abstract

The New Mexico Department of Health (NMDOH) Environmental Health Tracking Project has been compiling and analyzing data on air quality and respiratory health of New Mexicans. While other studies in the United States have shown an association between the frequency of asthma attacks and ground level ozone in large urban areas, few researchers have focused on largely rural communities in the desert southwest. To perform the analysis, the daily number of asthma-related emergency room visits to emergency departments for 2000 to 2003 were matched to daily ozone levels during April – September. The ozone concentration data were obtained from nationwide datasets compiled by the Environmental Protection Agency, but were collected by the NM Environment Department Air Quality Bureau. The study focused on ground level ozone during April to September because ground level ozone accumulates when warmer and longer days cause nitrogen oxides and volatile organic compounds in the air to react and generate ozone. These reactions can cause ozone concentrations to increase by more than 20 parts per billion (ppb) from one day to the next.

The analysis used a statistical model to predict the effect that these changes in ozone concentrations have on the number of asthma-related emergency room visits. Two health outcomes were considered: daily presence or absence of an asthma-related medical visit and the number of visits. Ozone was associated with asthma-related medical visits. The distribution of ozone concentrations was similar to that observed in many large cities. Increased ozone (lagged two days) was associated with increased odds of at least one asthma-related medical visit by 42 %. The study found that when ozone increased by 20 ppb the number of emergency room visits increased by about 34%. While this is a small increase in the number of visits, sensitive persons may want to monitor air quality index forecasts to help limit their exposure to ozone. Ozone concentrations typically are highest in the early afternoon, so sensitive individuals should try to reduce their outdoor activities during this part of the day.

Background

Exposure to air pollutants, such as ozone, nitrogen dioxide, sulfur dioxide and particulates, have repeatedly been shown to be associated with negative health outcomes, including mortality, reduced lung function growth and asthma (Dominici et al. 2003, Gauderman et al. 2000, Tolbert et al. 2000). However, most of these studies have been conducted in large urban areas, with many of these in the eastern United States or the western coast. The distribution of these air pollutants and the sources of these pollutants may differ considerably from rural areas or areas in the high desert Southwest.

In an Environmental Protection Agency (EPA) study of air quality in New Mexico, Sather showed that the ozone concentrations in San Juan County were increasing and were among the highest in EPA sites in the Southwest (Sather 2004). He further concluded that the levels were similar throughout most of the county and that NOx and alkanes were the main volatile organic compounds in the ozone development.

Health outcomes associated with air quality have not been studied in a rural, southwestern high desert environment. Thus, we conducted a study of asthma-related medical visits in San Juan County and present an alternative statistical approach that deals with some of the limitations of data obtained in a rural area.

Study Area

San Juan County, New Mexico is a rural county in the high desert of northwest New Mexico, with an elevation of 5145 feet and an average rainfall of 9.3 inches. The county covers over 5000 square miles, but had a population of 114,000 in 2000, resulting in a low density of 21 people per square mile. The main city is Farmington, with a population of 38,000. All other towns have a population under 10,000, with most being considerably smaller. Although the area is rural, the county residents are concerned about air pollution and the potential health risks, especially with respect to asthma. Major industries center on coal, oil and natural gas production. Air pollution sources include coal-based power plants and production of gas and oil. Two more large coal-fired power plants may be built within the county. With the increased number of forest fires in the West and the hundreds of miles that the smoke from these fires has traveled, forest fires also have had a considerable impact on the air quality.

Asthma Surveillance

Through a CDC cooperative agreement starting in 2000, the NMDOH developed a statewide asthma surveillance system. With renewed funding NMDOH has continued surveillance and has expanded its role to education, improving access to care and reducing the effects of environmental factors associated with asthma. In 2003, NMDOH received funding through the CDC Environmental Public Health Tracking Program to link environmental exposure data with health outcome data. As part of this program, NMDOH, in collaboration with the UNM, linked data on air quality and asthma in San Juan County. Both hospitalization discharge and urgent care visit information were obtained through the statewide asthma surveillance system for January 1, 2000 through December 31, 2003. Age, sex and zip code of residence were obtained for each visit.

Air Quality Data

New Mexico Environment Department (NMED) collected air quality data from three monitors within the county. The Bloomfield and San Juan Substation monitors ran continuously and collected hourly data on air quality and weather conditions. While both monitors were operating as of January 1, 2000, ozone was not collected at the Bloomfield station until June 7, 2000. The Bloomfield monitor is approximately 15 miles east of Farmington in the town of Bloomfield. The Substation is located at the Shiprock Electrical Substation, approximately 15 miles west of Farmington, near the Public Service Company of New Mexico San Juan Generating Station, and a few miles north of the Arizona Public Services Four Corners Power Generating Station.

Methods

Statistical Methods

Two health outcomes were considered: the number of asthma-related medical visits per day and a binary indicator as to whether or not any medical visits during a day were asthma-related. Since we were primarily interested in the association of ozone levels with asthma-related medical visits, we restricted the yearly study period to May 1 through September 15, when over 90% of the eight hour average ozone concentrations were above 50 ppb. Variables for which data were collected hourly were summarized as both the daily maximum hourly value and the maximum eight hour average value. While the maximum eight hour value for ozone is used in regulatory standards, we also wanted to consider if shorter term peaks, such as those indicated by high daily maximum hourly values, may be important to health outcomes. For measurements taken at two stations, the association between the two daily ozone values was assessed and the maximum of the two values was used.

Modeling

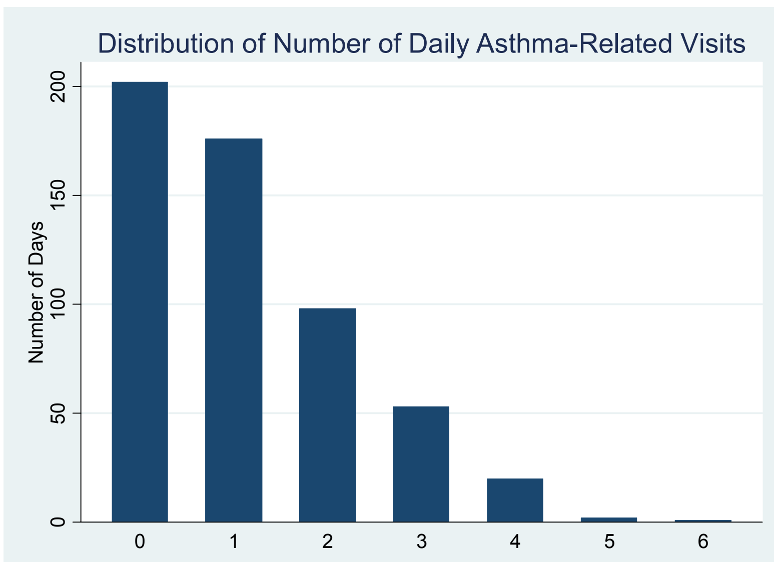
The daily number of asthma-related medical visits was modeled using Poisson regression. Primary exposure variables were the maximum daily values for the eight-hour average hourly ozone concentrations. Lags of zero to five days from exposure to visit day were examined to determine the amount of time between exposure and effect. Covariates were included to adjust for seasonal components, year, week day, holidays (lagged zero to two days) and school year. Variables were included only if the significance level was less than 0.10. Single pollutant models were obtained by adding an exposure variable to this best covariate model. Only the variables significant at $p<0.10$ in the single pollutant models were examined in the overall model, but these variables were retained only if the significance level was less than 0.05. Since the number of daily visits generally was small, logistic regression was used to model whether or not any asthma-related medical visit was observed on a day. The same procedure, including the same predictor variables and covariates, that was used in the Poisson regression modeling was used in the logistic regression modeling.

Since the number of daily asthma-related medical visits was small and the number of days with zero counts was larger than expected under the Poisson model, the Zero-Inflated Poisson (ZIP) model also was used (Dobbie and Welsch 2001; Hall and Zhang 2004). This model contains two components: the first predicts the probability of observing at least one asthma-related visit in a day (binary component) and the second estimates the number of visits (count component). The coefficients in the two components are estimated simultaneously. Only variables significant at < 0.10 at entry were retained. All statistical modeling was done in R.

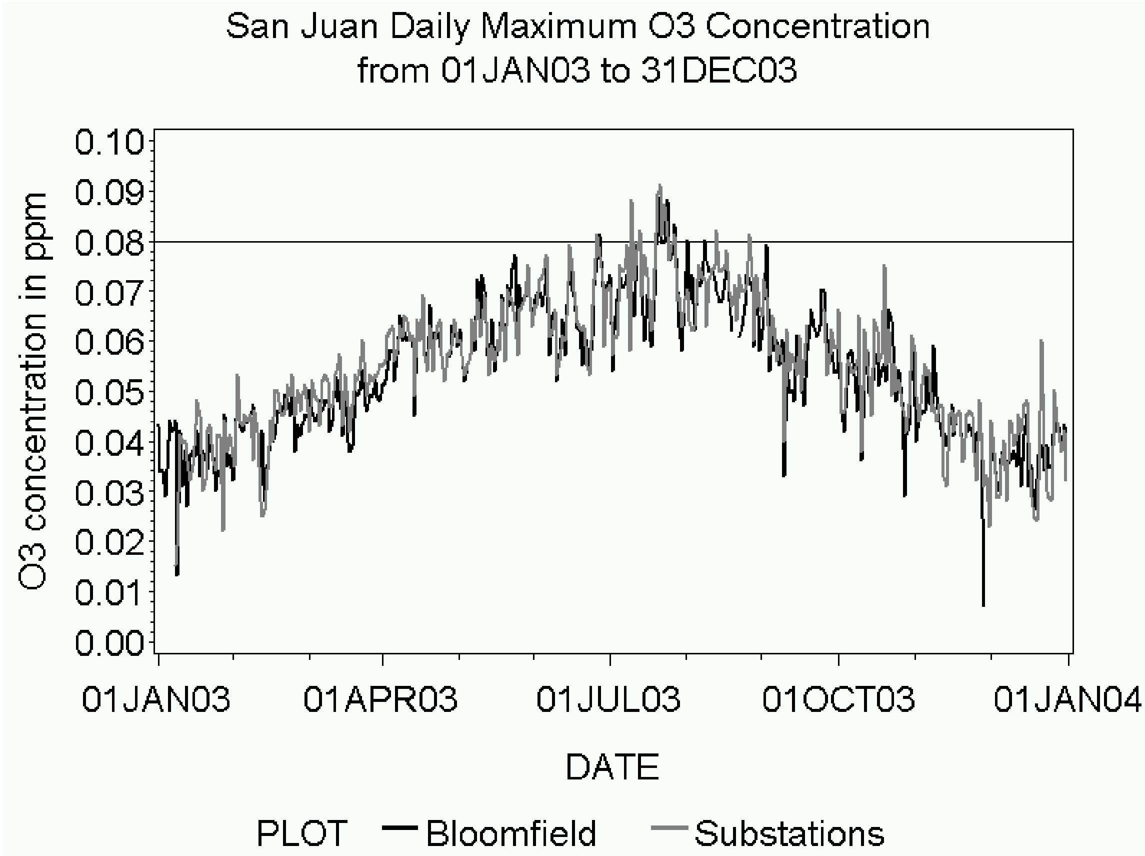
Results

Health Outcomes

During the summer months (May 1 through September 15) of 2000 through 2003, 627 asthma-related medical visits were reported in San Juan County. Asthma-related visits ranged from 0 to 6 per day, with a median of 1 and mode of 0 (Figure 2). At least one patient made an asthma-related visit on 350 (63.4%) of the 552 study days. Although age, gender and zip code information were available, the number of visits or proportion of days with an asthma-related visit were too low for successful modeling, so no assessment by these variables are included.



Air Quality: Ozone peaks during the summer months. Analyses were restricted to the summer months, from May 1 through September 15. Ozone concentrations at the two monitors were very similar. For air quality parameters that were measured at two monitors, the maximum value was used. The median daily eight hour maximum ozone level was 63 ppb during the summer months, with a maximum value of 85. All air quality variables exhibited distributions skewed to high values, but ozone was the least skewed. The maximum value for ozone was only 35% of the median.



Regression Models: To model the odds of at least one asthma-related medical visit, logistic regression models with adjustment for the seasonal components, weekday, holiday and spring school time were developed. The best lags were two days for ozone. Ozone was associated with increased odds of at least one asthma-related medical visit (OR=1.42; 95% CI: 1.09, 1.95; $p < 0.01$). To model the count of the number of asthma-related medical visits, Poisson regression models were also used with adjustment for the seasonal components, weekday, holiday and year. Ozone was associated with an increased count of visits, with a relative risk of 1.11 per 10 ppb ozone (95% CI: 0.98, 1.24). Zip models were used to simultaneously model the probability of any asthma-related medical visits and the number of visits per day. Adjustment factors were determined for the separate binary and count components, with no adjustment in the binary component and adjustment for the seasonal components, weekday, holiday and year in the count component. While ozone was significant in the binary component ($p<0.05$), the overall association was not significant ($p=0.09$).

Discussion

We have shown that ambient ozone concentrations are associated with asthma-related medical visits in a rural area of the high desert in San Juan County, New Mexico. While there is an indication that the number of visits rise along with increases in ozone, the most important result is that the odds of asthma-related visits increase with increasing ozone (1.42; 95% CI: 1.09, 1.85).

The basic association of increased asthma consequences with increased ozone has been shown in many urban areas. The distribution of ozone values in San Juan County is similar to those observed in other studies, but the extreme values are not necessarily as high in San Juan County. For example, while the highest single hour and eight-hour averages were 96 ppb and 83 ppb in San Juan County, respectively, studies in Atlanta had maximum one hour concentrations of 132 ppb, (Stieb et al. 1996; Tolbert et al. 2000). However, studies in Seattle (8-hour maximum=83.1 ppb) and Santa Clara County, CA (1-hour maximum=70 ppb) had similar, but slightly lower maximum concentrations (Lipsett et al. 1997; Norris et al. 1999).

The high values in San Juan County are of concern. The federal regulatory standard is 84 ppb for the three-year average of the annual fourth highest eight hour average. During the study period, the county reached a three-year average of 78 ppb. Furthermore, in an EPA study of air quality in New Mexico, Sather concluded that the ozone concentrations in San Juan County during 2000-2003 were higher than the previous three years and were among the highest among EPA regional sites in the Southwest including Arizona, Utah, Colorado, New Mexico and Texas (Sather 2004). Sather also showed that ozone was high in many parts of the county, including the middle of the county near the population center and the sparsely populated western and northeastern parts of the county. The largest hourly change in ozone concentrations was only 18 ppb, indicating that nitrogen oxides and alkanes were the main compounds in the ozone development. Similar to studies of urban areas, the most effective lag is two days between the occurrence of the ozone concentration and the asthma-related visits (Hwang et al. 2004; Stieb et al. 1996).

Studies to address health issues in rural areas are more often hampered by small counts than similar studies in urban areas. Use of standard methods such as Poisson regression may not be appropriate, and the modification of the data to look at binary outcomes may lose vital information. Thus, a model such as the ZIP model may be appropriate in many rural health studies, as in other studies with small counts.

This study includes several limitations. As discussed above, studies in rural areas are often limited by small sample sizes. However, our modeling approach effectively dealt with small, including zero, counts. While the county covers a large area, there were only two monitors for each air quality parameter. Furthermore, address information was limited to zip code, so there was no effective method to obtain better exposure information than that obtained from one monitor or the average of two monitors. However, we did limit the study sample to people residing in the county. Prior studies of the spatial trends in ozone indicated some but not significant differences in ozone across the county.

Conclusions

Although a rural area, San Juan County, New Mexico experiences high ozone concentrations, as high as some urban areas and high for the Southwest. The analysis used a statistical model to predict the effect that these changes in ozone concentrations have on the number of asthma-related emergency room visits. Two health outcomes were considered: daily presence or absence of an asthma-related medical visit and the number of visits. Ozone was associated with asthma-related medical visits. The distribution of ozone concentrations was similar to that observed in many large cities. Increased ozone (lagged two days) was associated with increased odds of at least one asthma-related medical visit by 42 %. The study found that when ozone increased by 20 ppb the number of emergency room visits increased by about 34%. While this is a small increase in the number of visits, sensitive persons may want to monitor air quality index forecasts to help limit their exposure to ozone. Ozone concentrations typically are highest in the early afternoon, so sensitive individuals should try to reduce their outdoor activities during this part of the day.

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Regional Impacts of Oil and Gas Development on Ozone Formation in the Western United States

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ABSTRACT
The Intermountain West is currently experiencing increased growth in oil and gas production, which has the potential to affect the visibility and air quality of various Class I areas in the region. The following work presents an analysis of these impacts using the Comprehensive Air Quality Model with extensions (CAMx). CAMx is a state-of-the-science, "one-atmosphere" Eulerian photochemical dispersion model that has been widely used in the assessment of gaseous and particulate air pollution (ozone, fine [$PM_{2.5}$], and coarse [PM_{10}] particulate matter). Meteorology and emissions inventories developed by the Western Regional Air Partnership Regional Modeling Center for regional haze analysis and planning are used to establish an ozone baseline simulation for the year 2002. The predicted range of values for ozone in the national parks and other Class I areas in the western United States is then evaluated with available observations from the Clean Air Status and Trends Network (CASTNET). This evaluation demonstrates the model's suitability for subsequent planning, sensitivity, and emissions control strategy modeling. Once the ozone baseline simulation has been established, an analysis of the model results is performed to investigate the regional impacts of oil and gas development on the ozone concentrations that affect the air quality of Class I areas. Results indicate that the maximum 8-hr ozone enhancement from oil and gas (9.6 parts per billion [ppb]) could affect southwestern Colorado and northwestern New Mexico. Class I areas in this region that are likely to be impacted by increased ozone include Mesa Verde National Park and Weminuche Wilderness Area in Colorado and San Pedro Parks Wilderness Area, Bandelier Wilderness Area, Pecos Wilderness Area, and Wheeler Peak Wilderness Area in New Mexico.

IMPLICATIONS
Population growth in the western United States is driving a rapid increase in the generation of electricity and fossil fuel production, leading to higher NO_x emissions and the potential to affect the visibility and air quality of Class I areas in the region. Although total emissions from oil and gas development are small compared with other categories such as coal-fired power plants and automobiles, they occur in remote locations and can have a disproportionate effect on the air quality of national parks and wilderness areas. The following work provides an analysis of these impacts on ozone concentrations using a state-of-the-science photochemical dispersion model.

INTRODUCTION
High ozone (O_3) levels at the Earth's surface, such as the photochemical smog that frequently envelopes Los Angeles in the summer, have typically been regarded as an urban air quality problem. However, a disturbing trend in recent years has been the rise of tropospheric O_3 in remote regions of the western United States,[1] many of which are Class I areas (international parks, national wilderness areas that exceed 5000 acres in size, national memorial parks that exceed 5000 acres in size, and national parks that exceed 6000 acres in size) as designated by the Clean Air Act. Possible explanations for this trend include increasing background concentrations, largely due to emissions from Asia[2–4] or changes in the magnitude or distribution of regional emissions.[1]

O_3 is a strong oxidant that can reduce lung function and damage plant tissue at relatively low concentrations. In March 2008, the U.S. Environmental Protection Agency (EPA) tightened existing National Ambient Air Quality Standards (NAAQS) for O_3 to 75 parts per billion (ppb; assessed as the fourth highest monitored O_3 concentration value over a running average 8-hr period, averaged over 3 continuous years) from the previous 80 ppb, effectively reducing the compliance level of the O_3 NAAQS by 9 ppb. In April 2008, the EPA Clean Air Science Advisory Committee clarified earlier recommendations to the EPA administrator that a primary O_3 standard between 60 and 70 ppb is necessary to protect human health.[5]

O_3 is formed through a complex series of chemical reactions involving nitrogen oxides (NO_x) and volatile organic compounds (VOCs) in the presence of sunlight. To combat rising O_3 levels, these precursors must be reduced. However, as oil and gas development in the western United States continues to accelerate, there is significant potential that emissions from these sources will exacerbate the existing O_3 problem. Although emissions from oil and gas development may appear small as compared with other emission categories such as coal-fired power plants and automobiles, they typically occur in remote regions of the country, far removed from urban areas, and can have a disproportionate effect on the air quality of Class I areas. For example, NO_x emissions from an internal combustion engine at a gas well may react with terpenes (a reactive VOC) emitted from pine forests and form O_3 in an area where the right mix of precursors was previously not available for this reaction to take place. This is especially worrisome because recent observations indicate that many remote wilderness areas and national parks, such as Mesa Verde National Park in southwestern Colorado, are confronted with O_3 concentrations that are trending toward the EPA's acceptable limits. Very near Mesa Verde National Park are rapidly growing oil and gas extraction operations in northwestern New Mexico. As this type of development continues throughout the west, it is essential to understand its potential negative impact on air quality in some of our nation's most cherished protected areas. It is important to notice that wintertime O_3 concentrations exceeding 140 ppb were recently observed near the Jonah-Pinedale Anticline natural gas field in Wyoming's Upper Green River Basin.[6]

This study uses sophisticated meteorological and air pollution models to simulate air quality in the western United States, with a particular focus on O_3 concentrations in our national parks and wilderness areas. The Western Regional Air Partnership (WRAP) provided the necessary inputs to the model for meteorology, emissions, and boundary concentrations, originally developed for regional haze analysis and planning. The modeling system used in this work is similar to other systems used in demonstrating compliance with current NAAQS.[7,8]

Understanding the impacts of emissions from particular source categories such as oil and gas development is crucial to develop effective strategies that help reduce regional air pollution. Although this article focuses on the impact of O_3 pollution, the concept of "one-atmosphere" computer modeling is identified in the WRAP 2008-12 Strategic Plan for future regional air quality analyses.[9] This approach is used to investigate several issues related to regional formation and transport of air pollutants such as the primary and secondary NAAQS for O_3 and particulate matter, visibility protection, and mitigating health and ecosystem effects due to excessive nitrogen deposition and toxic air pollutants such as mercury.

APPROACH

The modeling system comprises three major components: the Penn State University/National Center for Atmospheric Research Mesoscale Model (known as MM5[10]), a regional weather model; CAMx (Comprehensive Air Quality Model with Extensions[11]), a chemistry transport model; and SMOKE (Sparse Matrix Operator Kernel Emissions[12]), an emissions processing system that chemically, spatially, and temporally allocates the raw emissions data. CAMx simulates the emissions, dispersion, chemical reactions, and removal of pollutants in the troposphere by solving the pollutant continuity equation for each chemical species on a three-dimensional grid. Although computationally expensive, this type of simulation accounts for the complex physical and chemical processes that govern the fate of pollutants. The 36-km coarse-grid horizontal domain used for the air quality modeling consists of the contiguous 48 U.S. states, contiguous lands and waters of southern Canada and northern Mexico, portions of the Pacific and Atlantic oceans, most of the Gulf of Mexico, all of the Gulf of California, and the southern Hudson Bay region. The CAMx 36-km grid includes 148 cells in the east-west dimension and 112 cells in the north-south dimension. The vertical grid used in the MM5 modeling defines the CAMx vertical structure. The MM5 simulations used a terrain-following coordinate system defined by pressure using 34 layers that extend from the surface to the model top at 100 mbar. To reduce computational costs, a layer-averaging scheme was adopted, reducing the original 34 layers to 19 vertical layers. Figure 1 presents a map of the computational modeling domain; it also shows the states that form the western region of the United States, the area of interest for this analysis. MM5 provides the wind fields that CAMx needs to determine the transport of chemical species, as well as other meteorological variables such as temperature and pressure. A detailed emission inventory specifies the hourly flux of emissions from numerous area and point pollutant sources. The emission inventory focuses on pollutants that are important for regional haze and visibility in the selected model domain, which includes the contiguous United States, southern Canada, and northern Mexico. The inventory consists of 22 emission categories (e.g., automobiles, power plants, forest fires, and oil and gas development) and was originally developed in support of WRAP's regional haze simulations.[13] Figure 2 shows the annual NO_x emissions associated with oil and gas development in the western United States. Note that significant emissions occur throughout the Intermountain West, particularly in the Four Corners region of northwestern New Mexico.

The oil and gas emission inventory used here was initially compiled for WRAP's regional modeling, with a focus on NO_x and oxidized sulfur (SO_x) emissions, which are precursors to fine particulate nitrate and sulfate, respectively. However, subsequent versions of this inventory have been developed and improved, and emissions of some species, such as VOCs, have been substantially revised. Although this study uses an earlier version of the WRAP oil and gas emission inventory, it is anticipated that the general trends presented provide a gross indication of the impact of this source category on regional O_3 formation.

In this study, a simulation for the year 2002 is performed with CAMx and corresponds to the "base modeling year" being investigated by WRAP and the latest year in which detailed emissions were readily available. The first step in this analysis is the comparison between predicted O_3 concentrations with available observations. Once the model performance of this base-case simulation is deemed adequate, a second CAMx simulation that includes all of the base-case emissions except those from oil

Figure 1. Map of the 36-km computational domain used in this study. The shaded area shows the analysis domain and corresponds to those states that are part of the contiguous WRAP region (Alaska and Hawaii are WRAP members, but are not in the modeling domain). The circles in the figure indicate the location of CASTNET sites used in this study for the model performance evaluation of O_3.

and gas is used to evaluate their air quality impacts in the western United States. The impacts are determined by looking at the difference between the base case and the "absent oil and gas emissions" simulations.

ANALYSIS

Model Performance Evaluation

O_3 concentrations predicted by the model are evaluated by comparing the surface layer values with available

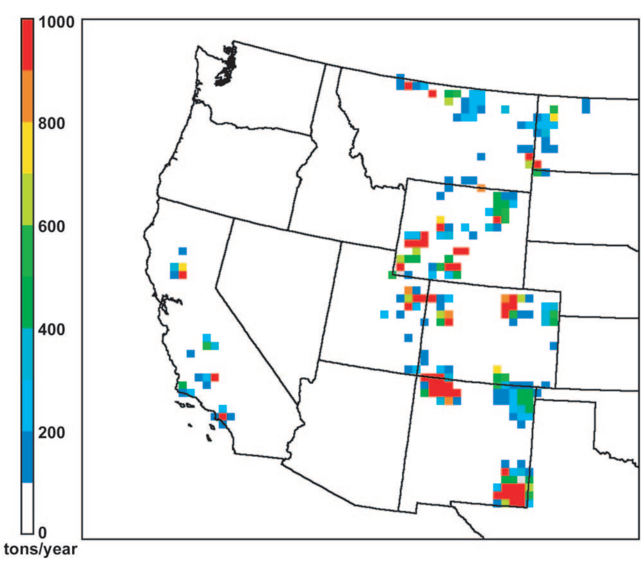

Figure 2. Annual 2002 WRAP NO_x emissions (t/yr) from oil and gas exploration and production activities in the western United States.

hourly measurements of ground-level O_3 at 22 sites from the Clean Air Status and Trends Network (CASTNET)[14] monitoring network. These sites fall within the western region of the United States and are indicated by circles in Figure 1. An evaluation of CAMx's skill in predicting O_3 is done in accordance with the EPA's suggested performance guidelines for O_3 modeling.[15,16] Observation/prediction pairs are excluded from the analysis when the observed concentration is below a certain cutoff level. The EPA has suggested a cutoff value of 60 ppb; however, most of the sites considered here are located in remote, pristine areas, and thus the cutoff value is set at 20 ppb because natural O_3 levels range typically between 10 and 25 ppb.[17] Table 1 shows the annual model performance statistics for 1-hr O_3 in the western region of the United States during 2002. In general, CAMx is able to consistently predict the general annual trends for O_3 concentrations, with a mean normalized bias of −1.6% and a mean absolute normalized error of 22.7%, falling well within the EPA's guidelines for acceptable model performance. Figure 3 shows estimated monthly normalized error and bias bar plots. Throughout the year, the model also performs within EPA goals; for instance, the largest errors are less than 25% during the summer (August). The model seems to show some seasonality in the errors and biases; its performance is better for the winter and fall and slightly worse for the spring and summer. The model has a tendency to underpredict O_3 concentrations during the summer and fall, with the largest biases in August (−15%), whereas it overpredicts O_3 during the winter and spring. Table 1 also shows the

Table 1. Annual model performance statistics for 1-hr O_3 calculated with 22 CASTNET sites in the contiguous WRAP region of the western United States.

Statistic	EPA Goal	Mesa Verde National Park	Gunnison National Park	Canyonlands National Park	Fitzpatrick	CASTNET Sites (Western United States)
Mean observation		46	50	48	48	47
Mean estimation		46	52	43	46	44
Standard deviation observations		10	9	10	8	13
Standard deviation estimates		13	10	11	9	12
Mean bias error		−0.02	2.6	−5	−1.5	−3
Mean normalized bias error (%)	$< \pm 15\%$	0.9	7.3	−8.4	−1.7	−1.6
Mean absolute gross error		8	7	9.6	7.2	10
Mean absolute normalized gross error (%)	$<35\%$	16.9	15.7	19.8	14.9	22.7
Mean fractional error (%)		16.9	14.6	22	15.2	23
Mean fractional bias (%)		−1.4	5.3	−11.9	−3.5	−5.8

Notes: All values in ppb except where indicated.

annual performance statistics for sites located near places for which the impacts from oil and gas emissions will be discussed in the following sections. It is important to notice that for these specific sites the predicted hourly O_3 concentrations also fall within EPA guidelines for acceptable model performance. In general, the performance in most of these sites is better than in the western United States as a whole, with normalized errors ranging from 14.9% (Fitzgerald) to 19.8% (Canyonlands National Park). Many of these sites are located in very complex terrain, so given the coarse resolution of the model, its performance is reasonable and even comparable to that of other studies.[18–20] Figure 4 shows 8-hr moving averages of predictions and observations for the CASTNET sites presented in Table 1. The figure illustrates that the model does not seem to accurately capture the complex diurnal variations in the observations. However, it shows that throughout the year the model follows the general trends revealed by the observations, particularly on a monthly average basis. In the case of Canyonlands, the model variation is larger than the other sites and the model has a pronounced tendency to underpredict observations during the summer and fall.

Oil and Gas Impacts

As indicated above, this study relies on two separate CAMx simulations to estimate the potential impacts of oil and gas emissions in the western United States. A more regional perspective of O_3 formation is illustrated in Figure 5. Figure 5a shows the highest 8-hr O_3 concentration at each model grid cell that occurred during the 2002 base-case simulation. As expected, there are high concentrations (exceeding 110 ppb) downwind of major urban areas such as Los Angeles, San Francisco, Salt Lake City, and Denver. The figure also demonstrates that for a large region of the southwestern United States that includes remote regions of Nevada, Wyoming, Utah, Arizona, New Mexico, and Colorado, the new 8-hr primary NAAQS-related threshold for ground-level O_3 (75 ppb) is exceeded at least once during 2002 for many Class I areas. Generally, these maxima occur during hot, sunny days with light winds, when the meteorology is most favorable for O_3 production. These periods also typically correspond to peak VOC emissions from biogenic and anthropogenic sources. The impact of NO_x and VOC emissions from oil and gas development on O_3 in the western United States is shown in Figure 5b. Note that the values for each grid cell in Figure 5b correspond to the dates for which O_3

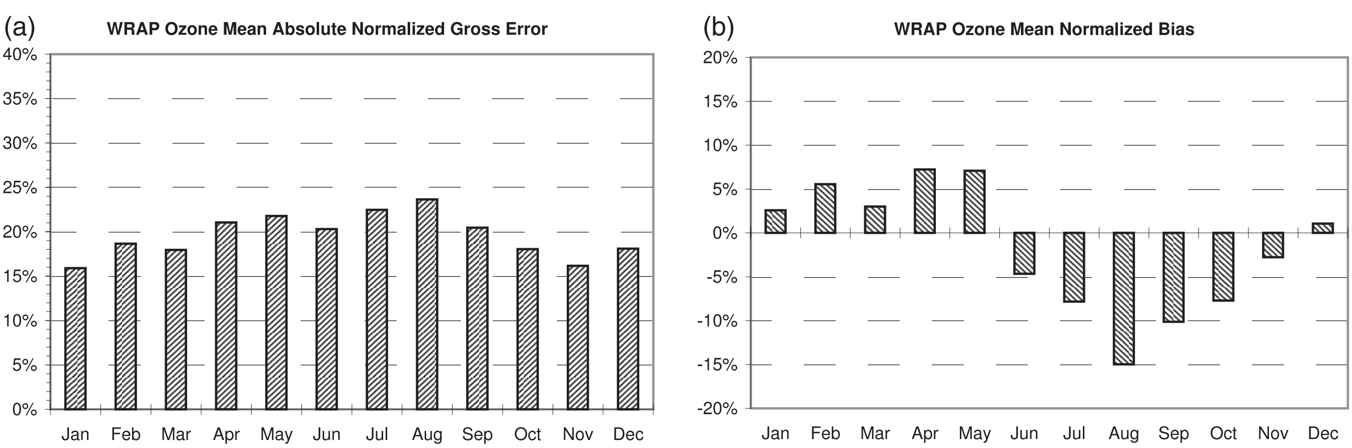

Figure 3. Monthly model performance (a) mean absolute normalized gross error and (b) mean normalized bias bar plots for 1-hr O_3 calculated with 22 CASTNET sites in the WRAP region.

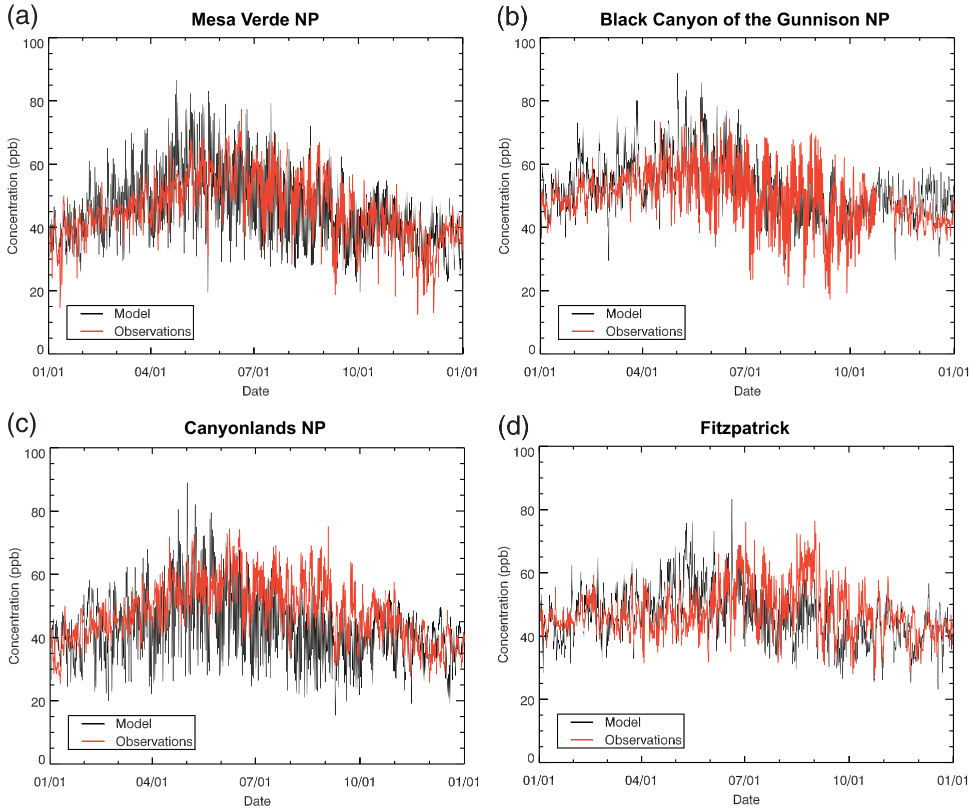

Figure 4. Time series comparison between model (black line) and observed (red line) 8-hr average O_3 (base case) for the CASTNET sites included in Table 1: (a) Mesa Verde National Park, (b) Black Canyon of the Gunnison National Park, (c) Canyonlands National Park, and (d) the Fitzpatrick Class I area included in Table 1.

maxima occur (Figure 5a), but in this case, the O_3 concentration is solely due to emissions from oil and gas development. Although the peak O_3 maxima throughout the west are typically quite small, there is a strong signature of 1–2 ppb of O_3 throughout New Mexico, Colorado, and Wyoming, with a pattern that approximates the

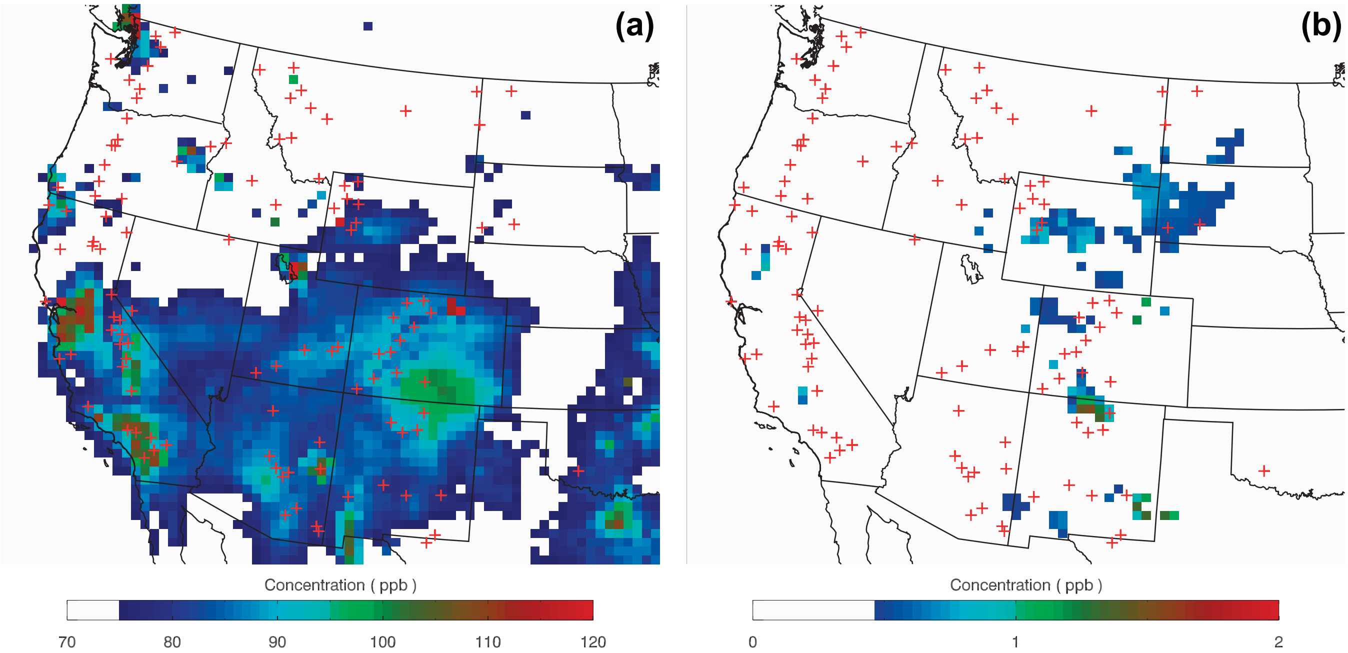

Figure 5. Peak predicted annual O_3 maxima (ppb, 8-hr average) in the western United States from (a) the 2002 base-case simulation and (b) the enhancement from VOC and NO_x emissions from oil and gas development that correspond to the dates and times of O_3 maxima. The locations of all Class I areas in the region are indicated with red crosses.

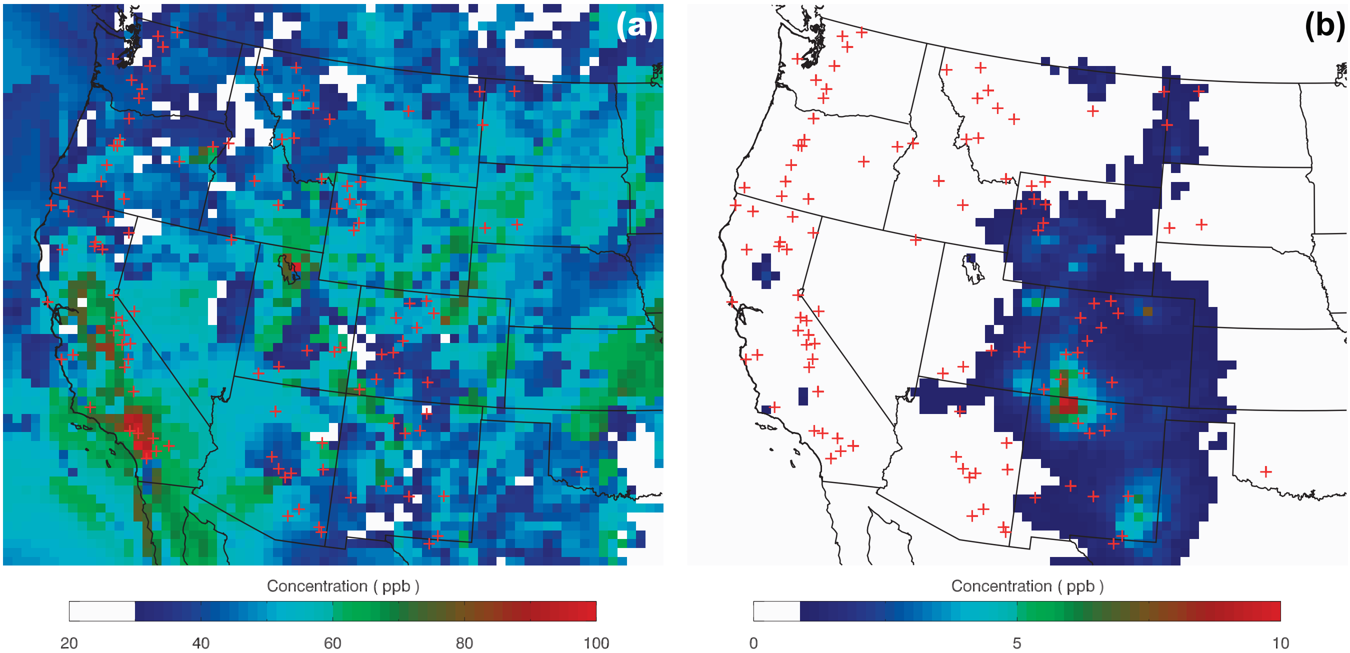

Figure 6. Peak predicted annual O_3 (ppb, 8-hr average) enhancement from VOC and NO_x emissions from (b) oil and gas development in the western United States and (a) corresponding O_3 concentrations from the 2002 base-case simulation. The locations of all Class I areas in the region are indicated with red crosses.

emissions shown in Figure 2. However, the maximum possible impacts of oil and gas emissions do not necessarily coincide in time with the maximum possible O_3 concentrations, as illustrated in Figure 6. The maxima 8-hr O_3 enhancement from oil and gas alone shown in Figure 6b demonstrates that significant O_3 concentrations (maximum of 9.6 ppb) could affect southwestern Colorado and northwestern New Mexico. Class I areas in this region that are likely to be impacted by increased O_3 include Mesa Verde National Park and Weminuche Wilderness Area in Colorado and San Pedro Parks Wilderness Area, Bandelier Wilderness Area, Pecos Wilderness Area, and Wheeler Peak Wilderness Area in New Mexico. O_3 concentrations for the base-case simulation during this period (Figure 6a) range from 40 to 70 ppb; thus in some places (e.g., Mesa Verde National Park and Weminuche) oil and gas have the potential to put these places out of compliance with the new EPA O_3 standard. Figure 6b shows that there are three regions where oil and gas have the potential for maximum impacts on Class I areas: southwestern Colorado and northern New Mexico, the southeast corner of New Mexico, and western Wyoming. Table 2 shows the date when the maximum impacts due to oil and gas emissions are achieved and their corresponding base-case concentrations for some of the Class I area sites. In general, these results show that most of the impacts occur during the summer and early fall. However, from this table alone it is not possible to know, for each site, the percentage of time when high impacts are observed in spring and early summer compared with summer and

Table 2. Maximum O_3 impacts due to oil and gas, date the maxima occur, and base-case concentration in some Class I area sites located in the western United States.

Class I Area	Latitude (°)	Longitude (°)	Base-Case Concentration (ppb)	Maximum Impact Oil and Gas (ppb)	Date Maximum Impact Occurs
Weminuche	37.65	−107.80	40	7	August 5
San Pedro Parks	36.11	−106.81	35	5	September 8
Carlsbad Caverns	32.14	−104.48	49	4	August 27
Wheeler Peak	36.57	−105.42	37	3	August 24
Pecos	35.93	−105.64	40	3	September 13
Bandelier	35.78	−106.26	61	3	June 30
Mesa Verde	37.20	−108.48	64	3	July 13
Saltcreek	33.61	−104.37	49	3	July 29
Great Sand Dunes	37.72	−105.51	33	2	September 8
La Garita	37.96	−106.81	38	2	August 6
Bridger	42.97	−109.75	52	2	April 4
Fitzpatrick	43.27	−109.57	52	2	April 4
Grand Teton	43.68	−110.73	50	1	April 24
Washakie	43.95	−109.59	44	1	September 10

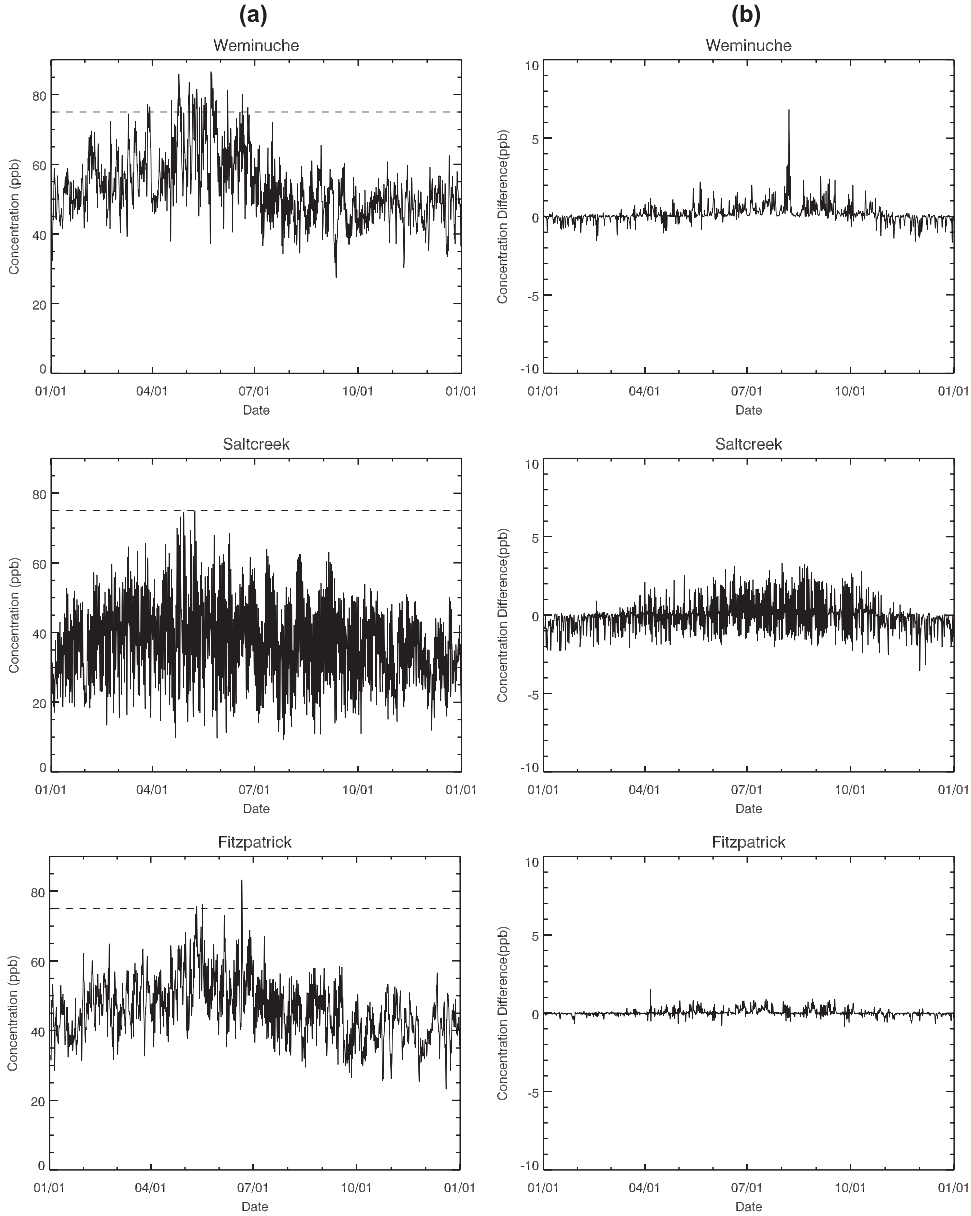

Figure 7. Time series of (a) simulated base-case O_3 (ppb, 8-hr average) for sites representative of one of the three main regions identified as having larger impacts from oil and gas emissions (Weminuche, Saltcreek, and Fitzpatrick Class I areas). (b) The change in O_3 concentration (ppb, 8-hr average) at each site solely due to VOC and NO_x emissions from oil and gas development.

early fall. Figure 7 is a much better indicator of this tendency. Figure 7 shows 8-hr moving average time series for the base case and the oil and gas impacts for a few selected sites from Table 2, including Weminuche, where the largest impacts are observed. The other sites represent one of the other two main regions identified as having larger impacts from oil and gas emissions. The general trend of modeled O_3 (Figure 7a) is low concentrations during the colder winter months, when limited photochemistry will occur, and higher concentrations during the warmer late spring and summer months, when meteorological conditions are more favorable to O_3 production. Additionally, enhanced biogenic VOC emissions that occur during the spring and summer will further influence O_3 formation in the region. The dashed lines in Figure 7a show the new EPA standards for O_3. It is evident from the figure that there are various instances in which O_3 concentrations are higher than the new NAAQS in many of these Class I areas, particularly during the late spring and early summer. Figure 7b shows the resulting changes in predicted O_3 concentrations that are attributed solely to emissions from oil and gas development. This estimate was calculated by evaluating two CAMx simulations: the base-case simulation, in which all emission categories are accounted, and a "no oil and gas" simulation, which is similar to the base case except that oil and gas emissions are removed. The difference between these two simulations represents the contribution of oil and gas emissions on regional O_3. Notable in Figure 7b is the fact that oil and gas emissions can actually decrease O_3 concentrations at various sites through the process of "NO_x scavenging," in which available O_3 is consumed by reacting with nitric oxide (NO). This effect is most prevalent in the winter, when O_3 concentrations are lower. However, in the summer, the situation is reversed, and warm, stagnant conditions yield an increase in O_3 from oil and gas emissions. Although these impacts appear relatively small (e.g., an increase of a few ppb in the summer), it should be remembered that this period corresponds with seasonally high O_3 concentrations.

CONCLUSIONS

A regional air quality model has been applied to the western United States to investigate the impacts of emissions from oil and gas development on O_3 concentrations. Incremental O_3 increases (8-hr average) ranging from less than 1 to 7 ppb were predicted at several western Class I areas, and a peak incremental O_3 concentration of 10 ppb was simulated in the Four Corners region. This study, although not exhaustive, does indicate a clear potential for oil and gas development to negatively affect regional O_3 concentrations in the western United States, including several treasured national parks and wilderness areas in the Four Corners region. It is likely that accelerated energy development in this part of the country will worsen the existing problem. The formation of O_3 pollution examined here represents a complex phenomenon involving nonlinear physical and chemical processes, uncertain emission inventories, and fine-scale transport in mountainous terrain. These simulations will be refined when updated emission inventories are available from WRAP. Regional air quality modeling requires significant resources but remains the only feasible option for developing emission control strategies that have the potential to reduce O_3 concentrations and protect air quality.

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Ozone Impacts of Natural Gas Development in the Haynesville Shale

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The Haynesville Shale is a subsurface rock formation located beneath the Northeast Texas/Northwest Louisiana border near Shreveport. This formation is estimated to contain very large recoverable reserves of natural gas, and during the two years since the drilling of the first highly productive wells in 2008, has been the focus of intensive leasing and exploration activity. The development of natural gas resources within the Haynesville Shale is likely to be economically important but may also generate significant emissions of ozone precursors. Using well production data from state regulatory agencies and a review of the available literature, projections of future year Haynesville Shale natural gas production were derived for 2009−2020 for three scenarios corresponding to limited, moderate, and aggressive development. These production estimates were then used to develop an emission inventory for each of the three scenarios. Photochemical modeling of the year 2012 showed increases in 2012 8-h ozone design values of up to 5 ppb within Northeast Texas and Northwest Louisiana resulting from development in the Haynesville Shale. Ozone increases due to Haynesville Shale emissions can affect regions outside Northeast Texas and Northwest Louisiana due to ozone transport. This study evaluates only near-term ozone impacts, but the emission inventory projections indicate that Haynesville emissions may be expected to increase through 2020.

Introduction

The Haynesville Shale is a rock formation that lies at depths of 10,000 to 13,000 feet below the surface and straddles the border between Northeast Texas and Northwest Louisiana near Shreveport (Figure 1). This formation is estimated to contain very large recoverable reserves of natural gas (*1*, *2*), and during the two years since the drilling of the first highly productive wells in 2008, it has been the focus of intensive exploration and leasing activity (*3*). Despite the economic downturn of 2009 and associated fall in price of natural gas, development of the Haynesville Shale has continued (*4*).

The development of natural gas resources within the Haynesville Shale is likely to be economically important but may also generate significant emissions of ozone precursors. Nitrogen oxides (NOx) are emitted during well drilling and subsequent rock fracturing to stimulate natural gas production as well as from compressor engines that are used to produce and transmit the gas. Volatile organic compounds (VOCs) are emitted from many processes including venting and completion of wells, dehydration of produced natural gas and fugitive emissions from well and pipeline components.

To our knowledge, there have been no published studies of regional air quality impacts of shale gas development, although shale gas is projected to play an increasingly important role in meeting U.S. energy needs (*1*). Emissions resulting from developing the Haynesville Shale would be released in a region that is within and/or frequently immediately upwind of potential ozone nonattainment areas (*5*). Several counties within Northwest Louisiana and Northeast Texas as well as nearby Dallas-Fort Worth have been identified by the U.S. Environmental Protection Agency as areas that do not attain the 2008 ozone standard (*6*) of 75 ppb. In 2010, the EPA proposed a more stringent ozone standard (*7*) which heightens the importance of understanding how development in the Haynesville Shale may impact future ozone air quality in the region.

Methods

Haynesville Shale Emission Inventory. In this section, we describe the development of an emission inventory for sources related to projected natural gas exploration and production of the Haynesville Shale. This inventory does not include other regional sources such as power plants, motor vehicles, or biogenic emissions, nor does it include emissions from development of other oil- and gas-producing formations in the region. These non-Haynesville sources are accounted for in the ozone modeling via a separate emission inventory, as discussed in the Supporting Information.

Exploration and production in the Haynesville Shale began only recently in 2008; therefore, peer-reviewed published data that can be used in emission inventory development are extremely limited. Basic information, such as the geographic extent and recoverable reserves of the Haynesville Shale, is not yet known with certainty. Our strategy in developing estimates of future year activity and emissions was therefore to gather the best available information and cross-check among different sources of data where possible. The Texas Commission on Environmental Quality (TCEQ), Texas Railroad Commission (RRC), and the Louisiana Department of Natural Resources (LDNR) were contacted regarding production and activity within the Haynesville Shale. The RRC and LDNR provided drilling and production data, but recommended that the best source of estimates of future year activity and equipment use would be the energy producers active in the area. A survey was sent out to the producers identified on their company web pages, stockholder reports, or in venture capital firm reports as being major leaseholders in the Haynesville Shale as of March, 2009. Because so few wells had been drilled in the Haynesville Shale at that time, several producers felt that they did not yet have enough information to predict future year activity and production, and all of the producers declined to participate in the survey.

Using drilling and well production data from Texas and Louisiana state regulatory agencies and a review of the available literature, the spatial extent of the Haynesville Shale was defined (Figure 1), and projections of future year Haynesville Shale natural gas production for 2009−2020 were derived for three scenarios corresponding to limited,

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FIGURE 1. Spatial extent of the Haynesville Shale in Texas and Louisiana as defined in this study.

moderate, and aggressive development. The projection scenarios were constructed for each future year using two factors: (1) the number of new wells drilled (spuds) in each year and (2) production estimates for each new active well (derived from existing well decline curves). From these two factors, formation-wide spuds, well counts, and gas production were estimated. This analysis does not attempt to predict future economic conditions but attempts to take future economic variability into account by providing a range of potential future production estimates.

The 2001−2008 historical development in a similar nearby formation, the Barnett Shale near Dallas-Fort Worth, was used as a surrogate for modeling growth in drilling activity in the Haynesville Shale. 2001−2008 was a period of favorable natural gas prices that occurred after the development of the horizontal drilling and rock fracturing techniques that made extraction of shale gas economically feasible. The comparison to the Barnett Shale was made to determine a reasonable growth rate in development activity (determined by drilling counts per year) that can be assumed for the Haynesville Shale. For example, historical data from the Barnett Shale were used to constrain how rapidly drill rigs can be diverted from other regions into a more profitable area as well as indicate how quickly new infrastructure can be built to handle the increased gas production from a newly discovered formation. Further description of the Barnett Shale and the rationale for the use of its development as a surrogate for growth in the Haynesville Shale are provided in the Supporting Information.

Development was initialized with the number of drilling rigs operating in the Haynesville Shale during March 2009; this quantity was estimated through inspection of maps (*8*) of active drilling rigs in the area that were drilling development gas wells at depths between 10,000 and 15,000 ft in the counties shown in Figure 1. Three emissions scenarios were then developed. The "Low scenario" held constant the March 2009 drill rig count of 95 through 2012 until 2020. The "High scenario" grew the number of rigs to from the initial count of 95 in 2009 to 200 at the same growth rate as the 2001−2008 barnett Shale rig count. The "Moderate Scenario" grew the rig count to 200 at 50% of high scenario growth rate. The rig count was capped at 200 in the Moderate and High Scenarios to avoid predicting an unreasonably large number of rigs to be operating in the Haynesville Shale in future years. This number is close to the maximum number of drill rigs that have operated simultaneously in the Barnett Shale and is approximately ten percent of the entire U.S. fleet of drilling rigs (approximately 2000 in March 2009). The High Scenario has 170 rigs active in 2012; the 200 rig cap is reached in 2014, and the number of rigs is held fixed thereafter. The Moderate Scenario has 133 active rigs in 2012 and reaches 200 rigs in 2018. A chart showing the number of drilling rigs active in each year from 2009 to 2020 is shown in the Supporting Information.

The drill rig count for each growth scenario was used to determine the number of new wells drilled per year. Drilling records from the LDNR (*9*) were used to determine an average drilling duration of 63 days for spuds occurring in the Haynesville Shale. This duration includes the time needed to move a drilling rig to a new well site, mobilize the rig for drilling, drill the well, and demobilize the rig for transport to the next well site. Therefore, one drill rig was assumed to be able to drill a total of $365/63 = 5.8$ wells in one year. The current 2009 baseline drilling success factor was determined from the LDNR wells database (*9*) to be 55% for the Haynesville Shale region; this figure was determined to be the percentage of new active wells added to the region relative to the number of recorded spuds. With assumed technological improvements and better definition of the formation boundaries as exploration proceeds, our analysis assumes that the drilling success factor would improve to 100% by 2018 and would increase linearly between 2009 and 2018. In the High Scenario, there are projected to be 2181 active wells in 2012 and 10,714 wells in 2020; in the Low Scenario, 1568 wells are predicted to be active in 2012 and 5632 wells in 2020.

Using the well development estimates for each of the three scenarios and estimates for the typical gas production of a well over its lifetime, total gas production can be calculated for the three development scenarios. This analysis requires deriving estimates of typical well production over the time period 2009−2020, during which a well's production is expected to decline from an initial production peak. Haynesville Shale wells have been producing gas for a very limited time period (approximately 1 year at the time this analysis was conducted); therefore, long-term yearly production rates were unknown. To estimate long-term production rates, eight wells with the longest production were identified, and the production rates from the LDNR database (*9*) were analyzed to derive a representative decline curve for all Haynesville Shale wells (see the Supporting Information). There is significant uncertainty in this estimate, but development of the Haynesville Shale region is so recent that a more robust well decline data set was not available. The decline curve was extrapolated to the year 2020 by finding the best fit power law function for each well and then averaging over the eight wells to calculate a derived decline curve such that yearly well production could be determined for an "average" Haynesville Shale well. The power law function was chosen as a representative fit based on other historical well decline curves.

A separate literature search was conducted to determine the availability of additional published Haynesville Shale well decline curves. Two venture capital reports from Tristone Venture Capital (*2*) and Southern Star (*10*) contained well decline curves for the Haynesville Shale for a number of individual wells. The reported decline curves from venture capital sources were averaged together to develop a single reported well decline curve. The total cumulative per-well production from the reported curves is 5.2 billion cubic feet (bcf), compared to 1.9 bcf for the derived well decline curves. Both decline curves are shown in the Supporting Information. This analysis assumes that the lower, derived well decline curve is representative of the low and moderate development scenarios, and the reported well decline curve obtained from the venture capital reports is representative of the high development scenario.

Total Haynesville Shale production estimates for the period 2009−2020 were obtained by multiplying the number of active wells by the appropriate annual production rate determined from the decline curve and the year that each well was brought online and summing over all active wells. Cumulative gas production for each scenario is shown in the Supporting Information. These production estimates were then used to develop an inventory of potential emissions from future natural gas exploration and production in the Haynesville Shale for all three scenarios. For exploration and production sources, ozone precursor emission rates were estimated based on data gathered from published reports of emission inventories of natural gas production sources in the region (*11*, *12*). "On-the-books" federal or state regulations that would affect the emissions projections (e.g., Federal New Source Performance Standards, off-road engine Tier standards, East Texas Combustion Rule) were applied. A detailed description of the development of the inventory is given elsewhere (*13*).

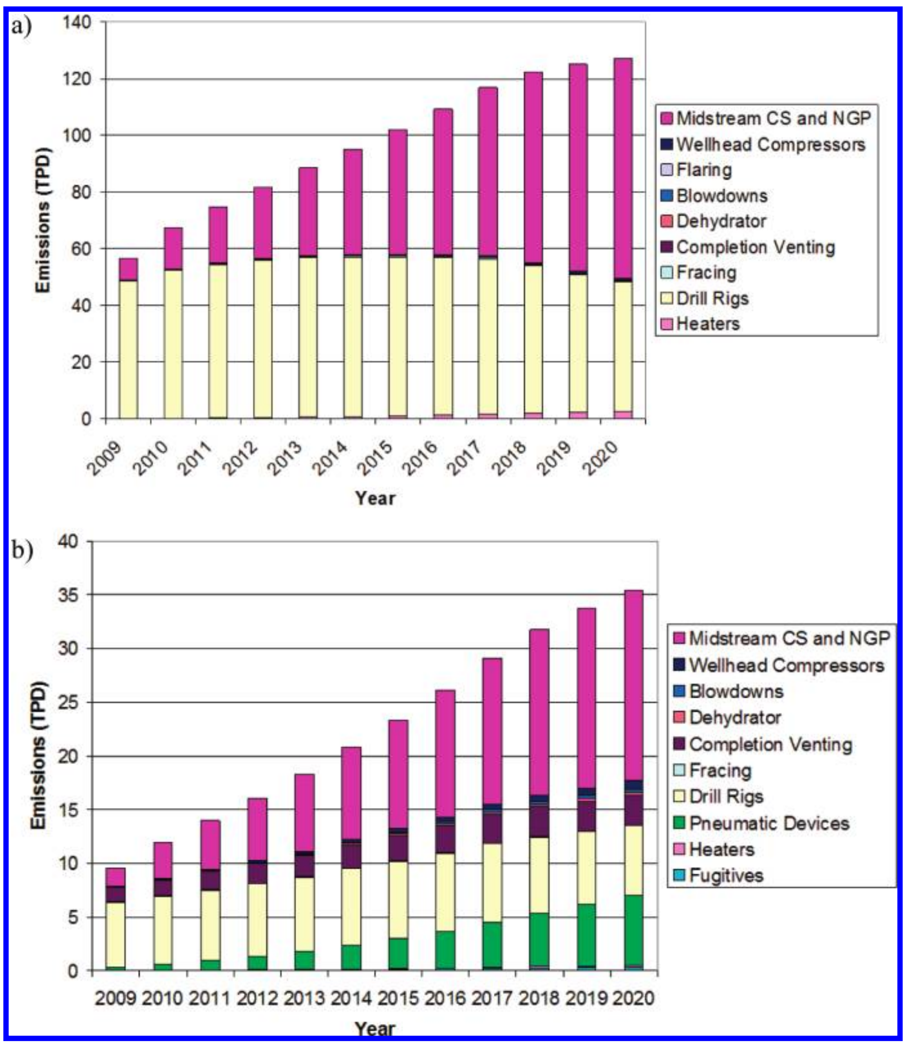

FIGURE 2. a) 2009 to 2020 moderate scenario Haynesville Shale formation-wide NOx emissions by source category and b) 2009 to 2020 moderate scenario Haynesville Shale formation-wide VOC emissions by source category. Midstream CS and NGP refer to central compressor stations (CS) and natural gas processing (NGP) facilities which transmit and process produced gas.

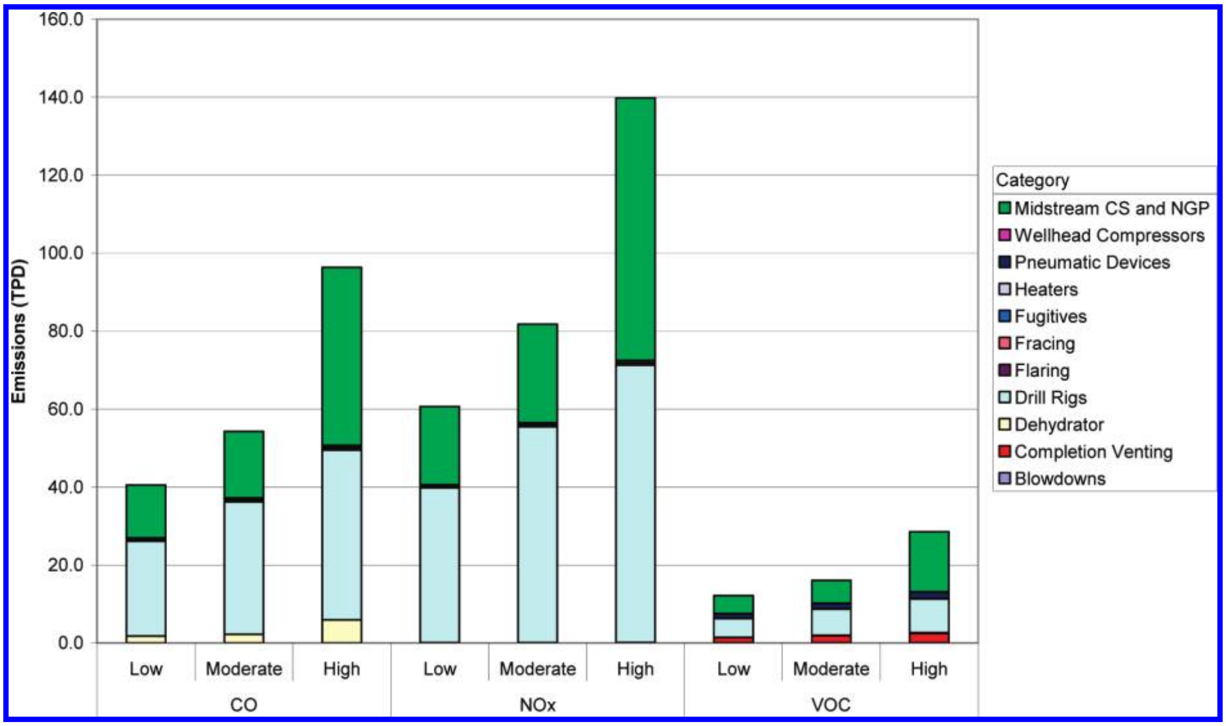

FIGURE 3. 2012 Haynesville Shale formation emissions of NOx, VOC, and CO by scenario and source category. Midstream CS and NGP refer to central compressor stations (CS) and natural gas processing (NGP) facilities which transmit and process produced gas.

Figure 2a shows the formation-wide NOx emissions for 2009−2020 for the moderate scenario. NOx emissions are projected to increase by 124% from 2009 to 2020. By 2020, development in the Haynesville Shale results in more than 120 tons/day of NOx emitted in northeast Texas and northwest Louisiana. Notably, drill rig NOx emissions remain relatively constant, while midstream compressor station and natural gas processing plant NOx emissions account for most of the increase. For the moderate scenario, the number of rigs in the Haynesville Shale region increases from 2009 to 2017, but the drill rig emissions flatten out and eventually decrease because of turnover in the drill rig engine fleet that results in replacement of older engines with higher Tier, cleaner-burning engines. Figure 2b shows that moderate scenario VOC emissions are projected to increase by 271% from 2009 to 2020. VOC emissions increases are primarily due to increases in midstream compressor station and natural gas processing plant VOC emissions, though pneumatic devices, drill rigs, and completion venting among other categories also contribute significantly to VOC emission increases.

Emissions of the ozone precursors NOx, VOC, and carbon monoxide (CO) for the entire Haynesville Shale formation for the 2012 modeling year are shown in Figure 3. Estimates of 2012 NOx emissions ranged from 61 tons/day in the low development scenario to 82 tons/day in the moderate scenario to 140 tons/day in the high scenario. These emissions increases are sufficiently large that it is necessary to evaluate their ozone impacts.

Ozone Modeling. The Comprehensive Air-quality Model with extensions (CAMx) (*14*) was used to model the eastern half of the United States using nested 36, 12, and 4 km resolution grids with the 4 km grid located over the Haynesville Shale region (Figure S1). CAMx is a three-dimensional, chemical-transport grid model used for tropospheric ozone, aerosols, air toxics, and related air-pollutants and is used for air-quality planning in Texas (*15, 16*) and Louisiana (*17*). CAMx was used here to estimate the near-term ozone impacts due to projected Haynesville Shale emissions during 2012.

The model's vertical resolution is finest near the ground (33 m surface layer) and extends to the lower stratosphere in 44 layers. The CAMx modeling databases were originally developed for current regulatory modeling of ozone in Houston and Northeast Texas. Meteorological input data for CAMx were developed using the PSU/NCAR Mesoscale Model version 5 (MM5) (*18*). The MM5 provides CAMx with hourly, gridded data for wind vectors, pressure, temperature, diffusivity, humidity, clouds, and rainfall. Emissions of VOCs, NOx, and CO from the TCEQ's 2005 emission inventory (*15*) were used. Boundary conditions for the outermost (36 km) grid were derived from a continental-scale CAMx run that was itself driven with data from a GEOS-Chem model (*19*) global simulation of 2005. The continental-scale CAMx run included the effects of episode-specific fire emissions derived from satellite observations. Large NOx sources were treated with the CAMx plume-in-grid submodel, and the model was run using a dry deposition algorithm (*20, 21*) developed for Environment Canada's AURAMS air quality forecasting model (*22*) that was newly implemented in CAMx.

The model was first applied for a historical episode during May 20-June 30, 2005 to evaluate its performance in simulating observed ozone and precursors. This analysis is described in (*23*) as well as in the Supporting Information. The model was found to reproduce observed ozone with good accuracy within the Texas-Louisiana-Arkansas-Oklahoma region. Projections of future year emissions for all regional sources unrelated to the Haynesville Shale were made for the year 2012 (*24*). A baseline 2012 model simulation was carried out in which the model was configured exactly as for the May-June 2005 simulation, except that the emission inventory of anthropogenic sources for 2005 was replaced with the 2012 anthropogenic emission inventory excluding emissions from the Haynesville Shale. This simulation is referred to as the 2012 baseline. Then, the 2012 simulation was repeated three times with emissions from the three (low, moderate, and high) Haynesville Shale emissions scenarios added to the 2012 emission inventory. The processing of the Haynesville emissions for use in CAMx, including spatial allocation of emissions, is discussed in the Supporting

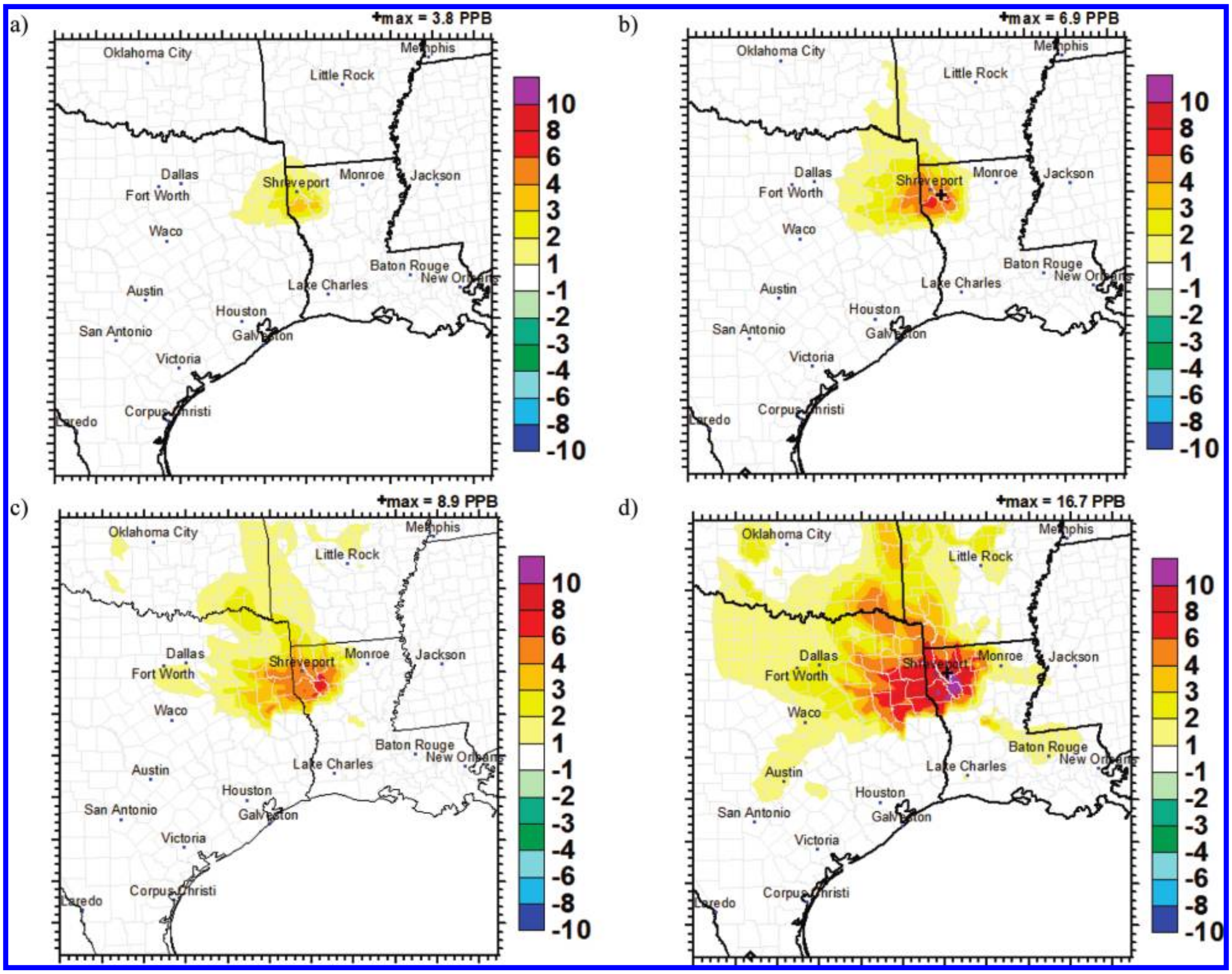

FIGURE 4. Twelve km grid ozone modeling results: a) Episode average difference in daily maximum 8-h ozone (ppb): Haynesville Low Secenario-2012 Baseline and b) Episode average difference in daily maximum 8-h ozone (ppb): Haynesville High Scenario-2012 Baseline and c) Episode maximum difference in daily maximum 8-h ozone (ppb): Haynesville Low Scenario-2012 Baseline and d) Episode maximum difference in daily maximum 8-h ozone (ppb): Haynesville High Scenario-2012 Baseline.

Information. The modeled ozone from each of these three scenarios is compared below to the 2012 baseline simulation ozone to isolate the ozone impacts of the Haynesville Shale for each emissions scenario.

Results and Discussion

Ozone Impacts. In presenting the ozone impacts of the Haynesville Shale, we focus on its effects on regional 8-h average ozone because of the relevance of this quantity to the National Ambient Air Quality Standard (NAAQS) for ozone (1-h ozone impacts are presented in the Supporting Information). We compute the difference in the daily maximum 8-h average ozone between the baseline 2012 run and each of the three Haynesville Shale runs in turn for each day of the May-June episode for all grid cells within the modeling domain. The average difference in the 8-h daily maximum ozone between each pair of runs is calculated for all times when the modeled 8-h ozone was greater than 60 ppb for at least one of the pair of runs. This restricts the analysis to periods of modeled high ozone within the May-June episode (i.e., nighttime and clean periods are removed from consideration). We look at the average difference across the entire May-June episode between the baseline 2012 run and each Haynesville emissions scenario run as well as the maximum difference between the pair of runs during the episode.

Comparisons of the differences in the May-June 2012 episode average daily maximum 8-h ozone are shown for the low and high Haynesville Shale scenarios in Figure 4 for the 12 km grid; we present the results on the 12 km grid to show impacts at the regional rather than local scale but note that the 4 km grid and 12 km grid were consistent in the magnitude of ozone impacts (not shown; see ref *24*). The ozone impacts from the moderate emissions scenario fall between the low and high cases and are not shown here for the sake of brevity.

Figure 4a shows that the episode average ozone impact of the emissions from the Haynesville Shale in the low scenario is largest in northwestern Louisiana, with peak increase of 4 ppb in southern Bossier Parrish. The area in which the episode average increase in daily maximum 8-h average ozone is larger than 1 ppb is mainly confined to northeast Texas and northwest Louisiana. In the high emissions scenario (Figure 4b), the episode average increase in daily maximum 8-h ozone has a similar pattern, but the increases are larger, with a peak of 7 ppb. There are areas of De Soto, Caddo, Bienville, Red River, and Bossier Parishes in Louisiana with episode average increases in the 6−8 ppb range. Texas counties Harrison, Panola, Rusk, Marion, and Shelby all experience average increases in the 4−6 ppb range, and Gregg and Cass Counties have regions where the average increase falls in the 3−4 ppb range. The region with episode average impacts greater than 1 ppb is larger in the high scenario than in the low scenario, extending eastward to the edge of Dallas-Fort Worth and northward into Oklahoma and Arkansas.

Figure 4c and 4d show the maximum differences in the daily maximum 8-h ozone between the Haynesville Shale and 2012 baseline runs for the low and high scenarios, respectively. In the high scenario, the peak increase is 17 ppb in southern Bossier Parish, and the area of increases greater than 6 ppb covers a broad swath of counties in northeast Texas and northwest Louisiana. The region of impacts greater than 4 ppb extends northward into Oklahoma and Arkansas, and the region of impacts between 2−3 ppb extends westward into the Dallas-Fort Worth area. The region of impacts ranging from 1−2 ppb includes McLennan, Travis, Hays, and Bexar Counties in Texas and the Baton Rouge area in Louisiana including Pointe Coupee, East and West Baton Rouge, and Livingston Parishes. The pattern of impacts is similar but less intense in the low scenario. These results show that the impacts of development in the Haynesville Shale may extend well outside the immediate vicinity of the Haynesville Shale into other regions of Texas and Louisiana and affect areas that may not attain the new 2010 ozone standard.

An ozone monitor's compliance with the NAAQS is reckoned using its design value, which is the three-year average of the fourth highest daily maximum 8-h ozone concentration. Changes in the ozone design value due to Hayneville Shale development relative to the baseline 2012 run were calculated for the low and high Haynesville scenarios. The design value analysis was carried out for currently active ozone monitors within the 4 km grid using EPA's Modeled Attainment Test Software (MATS (*25*)). MATS allows the model results to be used in a relative sense, scaling observed base year (2005) ozone design values with a ratio of model results for a base (2005) and a future year (2012) to project future year design values . This method is designed to reduce the uncertainty in future year projections due to any model bias that may be present, and is a standard technique in regulatory ozone modeling (*27*). Additional description of the method is provided in the Supporting Information.

Design values were calculated for three future cases: the baseline 2012 run, the 2012 Haynesville low scenario, and the 2012 Haynesville high scenario; the difference between the Haynesville scenario design values and the 2012 baseline design values was calculated to show the impact on the local design values of the additional emissions from Haynesville Shale development. The MATS results show 2012 design value increases for ozone monitors located within the Haynesville Shale counties of Harrison (TX), Bossier (LA), and Caddo (LA) of 2 ppb in the low scenario and 4−5 ppb in the high scenario. For the Gregg (TX) and Smith (TX) county monitors, which lie west of the Haynesville Shale, design value increases are smaller, ranging from 1 ppb for both monitors in the low scenario to 1−2 ppb in the high scenario.

Implications and Future Work. The magnitude of projected emissions and modeled 8-h ozone impacts described above indicate that development of the Haynesville Shale provides cause for concern about future ozone air quality in Texas and Louisiana. This analysis suggests that if the development of the Haynesville Shale proceeds at even a relatively slow pace, emissions from exploration and production activities will be sufficiently large that their potential impacts on ozone levels in Northeast Texas and Northwest Louisiana may affect the ozone attainment status of these areas. For example, the observed 2007−2009 design value at the Harrison County, TX monitor is 68 ppb, which complies with the 2008 NAAQS. The 4 ppb increase in the design value predicted for the high scenario would cause this monitor to fail to attain the full range of the 2010 NAAQS proposed by the EPA (60−70 ppb). The monitors in Gregg and Smith County have 2007−2009 design values of 75 and 74 ppb, respectively. They attain the 2008 NAAQS but are higher than the 60−70 ppb range of the proposed 2010 standard. The predicted increases in their design values due to Haynesville development would drive them further from attainment. Note that this study only evaluates near-term ozone impacts of development, but the emission inventory indicates that emissions may be expected to increase beyond 2012.

Additional study is required to refine the emission inventories used in this analysis. There is significant uncertainty associated with the emissions estimates since development in the Haynesville Shale is still in its early stages. This study forecasts emissions from development whose pace depends on a wide variety of factors that are subject to change. However, it is important to gain an understanding of the potential effects of this development and their impact on regional air quality; therefore, we account for uncertainty in the ozone model results by developing a range of emissions scenarios and presenting ozone impacts for the high and low scenarios as a method for bounding the uncertainty. The assumptions used in the development of the inventories - particularly the apparent limited need for wellhead compressors - indicate that these inventories could tend toward lower bound estimates. On the other hand, it is also possible that some source categories may be overestimated - for example, improvements in drilling technology could reduce future drilling times and therefore, NOx emissions associated with drilling. New controls or standards could also have a significant effect on future emissions and only on-the-books regulations were applied to the Haynesville inventory. Figure 2 shows that drill rigs and compressor stations and gas plants make the most significant contributions to the NOx emission inventory; additional controls on these sources would therefore be beneficial in reducing future year emissions from the Haynesville Shale. Future work will focus on enhancing the inventory with additional data regarding well site compression, well decline curves, and drill rig use.

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Supporting Information Available

Details describing the emissions estimation methodology, CAMx model, and model performance evaluation. This material is available free of charge via the Internet at http://pubs.acs.org.

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Hormones and Endocrine-Disrupting Chemicals: Low-Dose Effects and Nonmonotonic Dose Responses

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For decades, studies of endocrine-disrupting chemicals (EDCs) have challenged traditional concepts in toxicology, in particular the dogma of "the dose makes the poison," because EDCs can have effects at low doses that are not predicted by effects at higher doses. Here, we review two major concepts in EDC studies: low dose and nonmonotonicity. Low-dose effects were defined by the National Toxicology Program as those that occur in the range of human exposures or effects observed at doses below those used for traditional toxicological studies. We review the mechanistic data for low-dose effects and use a weight-of-evidence approach to analyze five examples from the EDC literature. Additionally, we explore nonmonotonic dose-response curves, defined as a nonlinear relationship between dose and effect where the slope of the curve changes sign somewhere within the range of doses examined. We provide a detailed discussion of the mechanisms responsible for generating these phenomena, plus hundreds of examples from the cell culture, animal, and epidemiology literature. We illustrate that nonmonotonic responses and low-dose effects are remarkably common in studies of natural hormones and EDCs. Whether low doses of EDCs influence certain human disorders is no longer conjecture, because epidemiological studies show that environmental exposures to EDCs are associated with human diseases and disabilities. We conclude that when nonmonotonic dose-response curves occur, the effects of low doses cannot be predicted by the effects observed at high doses. Thus, fundamental changes in chemical testing and safety determination are needed to protect human health. (*Endocrine Reviews* 33: 0000–0000, 2012)

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Abbreviations: A4, Androstenedione; AhR, aryl hydrocarbon receptor; BPA, bisphenol A; CDC, Centers for Disease Control and Prevention; DDE, dichlorodiphenyldichloroethylene; DDT, dichlorodiphenyltrichloroethane;DES, diethylstilbestrol; EDC, endocrine-disrupting chemicals; EPA, Environmental Protection Agency; ER, estrogen receptor; FDA, Food and Drug Administration; GLP, good laboratory practices; LOAEL, lowest observed adverse effect level; mER, membrane-associated ER; NHANES, National Health and Nutrition Examination Survey; NIS, sodium/iodide symporter; NMDRC, nonmonotonic dose-response curve; NOEL, no observed effect level; NOAEL, no observed adverse effect level; NTP, National Toxicology Program; PIN, prostatic intraepithelial neoplasias; POP, persistent organic pollutants; ppb, parts per billion; SERM, selective ER modulator; TCDD, 2,3,7,8-tetrachlorodibenzo-*p*-dioxin; WoE, weight of evidence.

I. Introduction

This review focuses on two major issues in the study of endocrine-disrupting chemicals (EDCs): low-dose exposures and nonmonotonic dose-response curves (NMDRCs). These concepts are interrelated, and NMDRCs are especially problematic for assessing potential impacts of exposure when nonmonotonicity is evident at levels of exposure below those that are typically used in toxicological assessments. For clarity of presentation, however, we will first examine each of the concepts separately.

A. Background: low-dose exposure

It is well established in the endocrine literature that natural hormones act at extremely low serum concentrations, typically in the picomolar to nanomolar range. Many studies published in the peer-reviewed literature document that EDCs can act in the nanomolar to micromolar range, and some show activity at picomolar levels.

1. What is meant by low dose?

In 2001, at the request of the U.S. Environmental Protection Agency (EPA), the National Toxicology Program (NTP) assembled a group of scientists to perform a review of the low-dose EDC literature (1). At that time, the NTP panel defined low-dose effects as any biological changes 1) occurring in the range of typical human exposures or 2) occurring at doses lower than those typically used in standard testing protocols, *i.e.* doses below those tested in traditional toxicology assessments (2). Other definitions of low dose include 3) a dose below the lowest dose at which a biological change (or damage) for a specific chemical has been measured in the past, *i.e.* any dose below the lowest observed effect level or lowest observed adverse effect level (LOAEL) (3), or 4) a dose administered to an animal that produces blood concentrations of that chemical in the range of what has been measured in the general human population (*i.e.* not exposed occupationally, and often referred to as an environmentally relevant dose because it creates an internal dose relevant to concentrations of the chemical measured in humans) (4, 5). This last definition takes into account differences in chemical metabolism and pharmacokinetics (*i.e.* absorption, distribution, and excretion of the chemical) across species and reduces the importance of route of exposure by directly comparing similar blood or other tissue concentrations across model systems and experimental paradigms. Although these different definitions may seem quite similar, using just a single well-studied chemical like bisphenol A (BPA) shows how these definitions produce different cutoffs for exposure concentrations that are considered low dose (Table 1). For many chemicals, including EDCs, a large number of studies meet the criteria for low-dose studies regardless of whether the cutoff point for a low dose was based on the range of typical human exposures, doses used in traditional toxicology, or doses that use an internal measure of body burden.

Whether low doses of EDCs influence disease is a question that now extends beyond the laboratory bench, because epidemiological studies show that environmental exposures to these chemicals are associated with disorders in humans as well (see for examples Refs. 6–16). Although disease associations have historically been observed in individuals exposed to large concentrations of EDCs after

TABLE 1. Low-dose definitions and cutoff doses: BPA and DEHP as examples

Chemical	Estimated range of human exposures	Doses below the NOAEL	Doses below the LOAEL	Administered doses (to animals) that produce blood levels in typical humans
BPA	0.4–5 μg/kg · d (679)	No NOAEL was ever established in toxicological studies (38)	<50 mg/kg · d (38)	~400 μg/kg · d to rodents and nonhuman primates (4, 253)
DEHP	0.5–25 μg/kg · d (680)	<5.8 mg/kg · d (681, 682)	<29 mg/kg · d (681, 682)	Unknown

Estimates of human exposure are made from consumer product consumption data but do not take into account that there are unknown sources of these chemicals. DEHP, Bis(2-ethylhexyl) phthalate.

industrial accidents (17–19) or via occupational applications (20–22), recent epidemiological studies reveal links between environmentally relevant low concentrations and disease prevalence. With the extensive biomonitoring studies performed by the U.S. Centers for Disease Control and Prevention (CDC) (23, 24) and similar environmental surveys performed in Europe (25) and elsewhere (www.statcan.gc.ca/concepts/hs-es/measures-mesures-eng.htm), knowledge about environmental exposures to EDCs and their associations with human health disorders has increased substantially.

Low-dose effects have received considerable attention from the scientific and regulatory communities, especially when examined for single well-studied chemicals like BPA (4, 27–32). The low-dose literature as a whole, however, has not been carefully examined for more than a decade. Furthermore, this body of literature has been disregarded or considered insignificant by many (33, 34). Since the NTP's review of the low-dose literature in 2001 (2), a very large body of data has been published including 1) additional striking examples of low-dose effects from exposures to well-characterized EDCs as well as other chemicals, 2) an understanding of the mechanisms responsible for these low-dose effects, 3) exploration of nonmonotonicity in *in vivo* and *in vitro* systems, and 4) epidemiological support for both low-dose effects and NMDRCs.

2. Is the term low dose a misnomer?

Endogenous hormones are active at extremely low doses, within and below the picomolar range for endogenous estrogens and estrogenic drugs, whereas environmental estrogen mimics are typically active in the nanomolar to micromolar range (for examples, see Refs. 35–38), although some show effects at even lower concentrations (39–41). Importantly, the definitions above do not take into account the potency or efficacy of the chemical in question, a topic that will be discussed in greater detail below. Instead, low dose provides an operational definition, in which doses that are in the range of human exposure, or doses below those traditionally tested in toxicological studies, are considered low. To be clear, none of these definitions suggest that a single concentration can be set as a low dose cutoff for all chemicals. Using the above definitions, for some chemicals, low doses could potentially be in the nanogram per kilogram range, but for most chemicals, doses in the traditional micro- and milligram per kilogram range could be considered low doses because traditional approaches to testing chemicals typically did not examine doses below the milligram per kilogram dose range.

B. Background: NMDRCs

We have defined low-dose studies according to the definitions established by the NTP panel of experts (2). However, because the types of endpoints that are typically examined at high doses in toxicological studies are often different from the types of endpoints examined in low-dose studies, one cannot assume that an effect reported in the low-dose range is necessarily different from what would be observed at higher doses. For example, low doses of a chemical could affect expression of a hormone receptor in the hypothalamus, an endpoint not examined in high-dose toxicology testing, and high doses could similarly affect this same endpoint (but are likely to be unreported because high doses are rarely tested for these types of endpoints). Thus, the presence of low-dose effects makes no assumptions about what has been observed at higher concentrations. (As discussed elsewhere, for the majority of chemicals in commerce, there are no data on health effects and thus no established high- or low-dose range.) Therefore, low-dose effects could be observed at the lower end of a monotonic or linear dose-response curve.

In contrast, the definition of a NMDRC is based upon the mathematical definition of nonmonotonicity: that the slope of the dose-response curve changes sign from positive to negative or vice versa at some point along the range of doses examined (42). Often NMDRCs have a U- or inverted U-shape (43); these NMDRCs are thus also often referred to as biphasic dose-response curves because responses show ascending and descending phases in relation to dose. Complex, multiphasic curves have also been observed (41, 44, 45). NMDRCs need not span from true low doses to high (pharmacologically relevant) doses, although experiments with such a broad dose range have been performed for several EDCs; the observation of nonmonotonicity makes no assumptions about the range of doses tested. Examples of NMDRCs from *in vitro* cell culture and *in vivo* animal experiments, as well as epidemiological examples, are presented in detail later in this review (see *Sections III.C.1–3*). Additional examples of NMDRCs are available in studies examining the effects of vitamins and other essential elements on various endpoints (see for example (46); these will not be examined in detail in this review due to space constraints.

NMDRCs present an important challenge to traditional approaches in regulatory toxicology, which assume that the dose-response curve is monotonic. For all monotonic responses, the observed effects may be linear or nonlinear, but the slope does not change sign. This assumption justifies using high-dose testing as the standard for assessing chemical safety. When it is violated, high-dose testing regimes cannot be used to assess the safety of low doses.

It should be noted that both low dose and nonmonotonicity are distinguished from the concept of hormesis, which is defined as a specific type of response whereby "the various points along [the dose response] curve can be interpreted as beneficial or detrimental, depending on the biological or ecological context in which they occur" (47). Estimations of beneficial or adverse effects cannot be ascertained from the direction of the slope of a dose-response curve (48–50). In their 2001 Low Dose Peer Review, the NTP expert panel declined to consider whether any effect was adverse because "in many cases, the long-term health consequences of altered endocrine function during development have not been fully characterized" (2). There are still debates over how to define adverse effects (51–53), so for the purposes of this review, we consider any biological change to be an effect. Importantly, most epidemiological studies are by definition examining low doses (unless they are focusing on occupationally exposed individuals), and these studies typically focus on endpoints that are accepted to be adverse for human health, although some important exceptions exist (54–56).

Finally, it is worth noting that any biological effect, whether it is observed to follow linear relationships with administered dose or not, provides conclusive evidence that an EDC has biological activity. Thus, other biological effects are likely to be present but may remain undetected or unexamined. Many EDCs, including those used as pesticides, were designed to have biological effects (for example, insecticides designed to mimic molting hormone). Thus, the question of whether these chemicals have biological effects is answered unequivocally in their design; the question is what other effects are induced by these biologically active agents, not whether they exist.

C. Low-dose studies: a decade after the NTP panel's assessment

In 2000, the EPA requested that the NTP assemble a panel of experts to evaluate the scientific evidence for low-dose effects and dose-response relationships in the field of endocrine disruption. The EPA proposed that an independent and open peer review of the available evidence would allow for a sound foundation on which the EPA could "determine what aspects, if any, of its standard guidelines for reproductive and developmental toxicity testing [would] need to be modified to detect and characterize low-dose effects" (2). The NTP panel verified that low-dose effects were observed for a multitude of endpoints for specific EDCs including diethylstilbestrol (DES), genistein, methoxychlor, and nonylphenol. The panel identified uncertainties around low-dose effects after exposure to BPA; although BPA had low-dose effects on some endpoints in some laboratories, others were not found to be consistent, leading the panel to conclude that it was "not persuaded that a low-dose effect of BPA has been conclusively established as a general or reproducible finding" (2).

Since the NTP's review of low-dose endocrine disruptor studies, only a few published analyses have reexamined the low-dose hypothesis from a broad perspective. In 2002, R. J. Witorsch (57) analyzed low doses of xenoestrogens and their relevance to human health, considering the different physiologies associated with pregnancy in the mouse and human. He proposed that low doses of endocrine disruptors would not likely affect humans because, although low-dose effects had been observed in rodents, the hormonal milieu, organs controlling hormonal release, and blood levels of estrogen achieved are quite different in humans. There are, of course, differences in hormones and hormone targets between rodents and humans (58), but the view that these differences negate all knowledge gained from animal studies is not supported by evolutionary theory (59–61). This human-centered stance argues against the use of animals for any regulatory testing (62) and runs counter to the similarities in effects of EDCs on humans and animals; rodents proved to be highly predictive of the effects of DES on humans (63, 64). In a striking example, studies from mice and rats predicted that gestational exposure to DES would increase mammary cancer incidence decades before women exposed *in utero* reached the age where this increase in risk was actually observed (65–67).

In 2007, M. A. Kamrin (68) examined the low-dose literature, focusing on BPA as a test case. He suggested that three criteria were required to support the low-dose hypothesis. First is reproducibility, which he defined as "the same results are seen from the same causes each time a study is conducted." Furthermore, he proposed that the dose response for the effects must be the same from study to study. Second is consistency, which he defined as the results all fitting into a pattern, whereby the results collected from multiple species and under variable conditions all show the same effect. And third is proper conduct of studies, which he defined as including the appropriate controls and performance under suitable experimental conditions as well as the inclusion of multiple doses such that a dose-response curve can be obtained.

Although we and others (69–72) agree with the use of these criteria (reproducibility, consistency, and proper experimental design), there are significant weaknesses in the logic Kamrin employed to define these factors. First, suggesting that reproducibility is equivalent to the same results obtained each time a study is conducted is unrealistic and not a true representation of what is required of replication. As has been discussed in other fields, "there is no end to the ways in which any two experiments can be counted as the same — or different . . . All experiments are the same in respect of their being experiments; they are all different by virtue of being done at different places, at different times, by different people, with different strains of rat, training regime, and so on" (73).

Furthermore, according to the Bradford-Hill criteria, a set of requirements accepted in the field of epidemiology to provide adequate evidence of a causal relationship between two factors, a single negative result (or even several studies showing negative results) cannot negate other studies that show adverse effects (74). Essentially, all scientists know that it is very easy for an experiment to find no significant effects due to a myriad of reasons; it is more difficult to actually find effects, particularly when using highly sophisticated techniques (69).

Second, the concept of consistency as a pattern that can be derived from all results is one we will use below, using a weight-of-evidence (WoE) approach and several specific examples. However, Kamrin's proposed idea that every study must show the same effect has the same weaknesses as discussed for the proposed definition of reproducibility and does not acknowledge the obvious differences in many species and strains. It also suggests that the identification of a single insensitive strain could negate any number of positive studies conducted with appropriate animal models (75).

And finally, Kamrin suggested that only studies with appropriate controls should be used for analyses, a criterion we agree should be followed. However, his own scrutiny of the low-dose animal literature fails to do so (68). He also suggested that studies use multiple doses so that a dose-response curve can be obtained. Although studies using a single dose can be informative, we agree that dose-response relationships provide important information to researchers and risk assessors alike. However, this requirement is not helpful if there is an insistence on observing a linear response; as we discuss in depth in this review, there are hundreds of examples of nonmonotonic and other nonlinear relationships between dose and endpoint. These should not be ignored.

In 2004, Hayes (76) reviewed the available literature concerning the effects of atrazine on amphibian development, with a specific focus on the effect of ecologically relevant doses of this EDC on malformations of the gonads and other sexually dimorphic structures; in the case of aquatic exposures, it can be difficult to determine what a cutoff for a low dose would be; thus, Hayes focused on studies examining the effects of atrazine at levels that had been measured in the environment. He reviewed the results produced by several labs, in which it was independently demonstrated that low concentrations of atrazine produced gonadal abnormalities including hermaphroditism, males with extra testes, discontinuous gonads, and other defects. Hayes' work also clearly addressed the so-called irreproducibility of these findings by analyzing the studies that were unable to find effects of the pesticide; he noted that the negative studies had multiple experimental flaws, including contamination of the controls with atrazine, overcrowding (and therefore underdosing) of experimental animals, and other problems with animal husbandry that led to mortality rates above 80%.

In 2006, vom Saal and Welshons (77) examined the low-dose BPA literature, identifying more than 100 studies published as of July 2005 that reported significant effects of BPA below the established LOAEL, of which 40 studies reported adverse effects below the 50 μg/kg · d safe dose set by the EPA and U.S. Food and Drug Administration (FDA); all of these studies would be considered low dose according to the NTP's definition (2). The authors proposed that these examples should be used as evidence to support the low-dose hypothesis. Furthermore, this publication detailed the similarities among the studies that were unable to detect any effects of low doses of BPA and established a set of criteria required to accept negative studies. We have adapted the criteria detailed by Hayes (76) and vom Saal and Welshons (77) to produce a set of requirements for low-dose studies; these criteria are described in some detail below.

D. Why examine low-dose studies now?

The developmental origins of health and disease hypothesis originated from studies showing that fetal DES exposure could cause severe malformations and cancers of the reproductive tract, and other studies demonstrating that fetal malnutrition could lead to adult diseases including metabolic syndrome, diabetes, and increased stroke incidence (78–81). Since that time, the developmental origins of health and disease hypothesis has been extended to address whether diseases that are increasing in prevalence in human populations could be caused by developmental exposures to EDCs (67, 82–85). Evidence from the animal literature has been tremendously informative about the effects of EDC exposures early in development and has driven new hypotheses to be tested in epidemiology studies (86). Studies including several discussed in this review provide supportive evidence that the fetal and neonatal periods are specifically sensitive to chemicals that alter endocrine signaling and that EDCs could be contributing to a range of diseases.

Strong, reliable, and reproducible evidence documents the presence of low concentrations of EDCs and other chemicals in human tissues and fluids, as well as in environmental samples (28, 87–89). These studies indicate that samples collected from humans and the environment typically contain hundreds of contaminants, usually in the parts-per-billion (ppb) range (90, 91). The obvious question with potentially large public health implications is whether these concentrations are so low as to be irrelevant to human health. The fact that epidemiological analyses (reviewed in *Section III.C.3*) repeatedly find associations between the measured concentrations in human samples and disease endpoints suggests it is inappropriate to assume the exposures are too low to matter. That is especially the case given the empirical data (reviewed in *Section II.A*) from animal and cell culture experiments showing effects can be caused by concentrations comparable (and sometimes below) what is measured in humans and also the detection of NMDRCs in some of those same experiments.

In the human biomonitoring field, large databases such as the CDC's National Health and Nutrition Examination Survey (NHANES) have allowed researchers to make comparisons between groups of individuals with various exposure criteria; some of these studies will be addressed in detail in subsequent sections of this review. Although by definition these databases examine low-dose exposures, their use has been the subject of significant debate. Because of the large number of chemicals that have been measured (>300 in the most recent NHANES by the CDC) and the large number of health outcomes and other disease-related data collected from the individuals that donated biological samples, it has been argued that the number of possible associations that could be made would lead to a significant number of false positives (92); thus, associations could be found simply because of extensive data dredging. This has led some to suggest that these studies as a whole should be rejected (93, 94).

In response to these criticisms, epidemiologist Jan Vandenbroucke (95) notes, "researchers do not mindlessly grind out one analysis after another"; the examination of these databases for associations between chemical exposures and health effects does not entail the statistical comparison between all possible factors, calculated as some 8800 comparisons in the CDC's NHANES database (92). Instead, epidemiologists typically focus on a select number of comparisons that address relationships between chemicals and diseases identified *a priori* (96, 97), often because of mechanistic data obtained in laboratory animals or *in vitro* work with human and animal cells and tissues. Repeated findings of links between EDC exposures and diseases in epidemiological analyses of biomonitoring data based on *a priori* hypotheses suggests these relationships should not be rejected as a statistical artifact and, instead, should be the basis for significant concern that low-dose effects can be detected in the general population (85, 98).

E. Mechanisms for low-dose effects

The endocrine system is particularly tuned to respond to very low concentrations of hormone, which allows an enormous number of hormonally active molecules to coexist in circulation (38). As a ligand-receptor system, hormones act by binding to receptors in the cell membrane, cytosol, or the nucleus. The classical effects of nuclear hormone receptors influence gene expression directly, although rapid nongenomic actions at membrane-associated receptors are now well documented and accepted. Membrane receptors are linked to different proteins in the cell, and binding to these receptors typically changes cellular responses in a rapid fashion (99), although the consequence of a rapid signaling event could be the activation of a nuclear transcription factor, leading to responses that take longer to detect. Peptide hormones can also influence gene expression directly (see Refs. 100 and 101 for examples).

There are several means by which the endocrine system displays specificity of responses to natural hormones. Many hormone receptors are expressed specifically in a single or a few cell types (for example, receptors for TSH are localized to the thyroid), whereas some (like thyroid hormone receptors) are found throughout the body (102). For receptors that are found in multiple cell types, different effects are produced in part due to the presence of different coregulators that influence behaviors of the target genes (103–105). And finally, some hormones have multiple receptors [for example estrogen receptor (ER)α and ERβ], which are expressed in different quantities in different cell types and organs and can produce variable effects on gene expression or cellular phenomena (cell proliferation *vs.* apoptosis) (102, 106).

The typical physiological levels of the endogenous hormones are extremely low, in the range of 10–900 pg/ml for estradiol, 300–10,000 pg/ml for testosterone, and 8–27 pg/ml for T_4 (see Table 2). Importantly, steroid hormones in the blood are distributed into three phases: free, representing the unconjugated, unbound form; bioavailable, representing hormones bound to low-affinity carrier proteins such as albumin; and inactive, representing the form that is bound to high-affinity binding proteins such as SHBG or α-fetoprotein (38) (Fig. 1A). When the circulating levels in blood are corrected for the low fraction of the hormones that are not bound to serum binding proteins, the free concentrations that actually bring about effects in cells are even lower, for example 0.1–9 pg/ml for estradiol. Concentrations of active hormones will vary based on the age and physiological status of the individual (*i.e.* plasma testosterone levels are less than 1 ng/ml in male children but increase to approximately 5–7 ng/ml in adulthood; during menses, estradiol levels are typically less than 100

TABLE 2. Ranges of endogenous hormones in humans (from Ref. 108)

Hormone	Free concentration (females)	Total concentration (females)	Free concentration (males)	Total concentration (males)
Cortisol	20–300 ng/ml		20–300 ng/ml	
Estradiol	0.5–9 pg/ml (adult female)	<20 pg/ml (prepubertal) 20–800 pg/ml (premenopausal) <30 pg/ml (postmenopausal)		10–60 pg/ml (adult)
Progesterone		0.2–0.55 ng/ml (prepubertal) 0.02–0.80 ng/ml (follicular phase) 0.90–4 ng/ml (luteal phase) <0.5 ng/ml (postmenopausal)		0.1–0.4 ng/ml (prepubertal) 0.2–2 ng/ml (adult)
Insulin		0–250 pmol/liter		0–250 pmol/liter
GH		2–6 ng/ml		2–6 ng/ml
Prolactin		0–15 ng/ml		0–10 ng/ml
Testosterone	9–150 pg/ml (adult)		0.3–250 ng/ml	
Thyroid hormone	8–30 pg/ml (10–35 pM)		8–30 pg/ml (10–35 pM)	
TSH	0.5–5 μU/ml		0.5–5 μU/ml	

pg/ml, but just before ovulation, they spike to 800 pg/ml; *etc.*) (107, 108). Of course, it should be noted that active concentrations of natural hormones vary somewhat from species to species and can even vary between strains of the same species (109).

There are several reasons why endogenous hormones are able to act at such low circulating concentrations: 1) the receptors specific for the hormone have such high affinity that they can bind sufficient molecules of the hormone to trigger a response, 2) there is a nonlinear relationship between hormone concentration and the number of bound receptors, and 3) there is also a nonlinear relationship between the number of bound receptors and the strongest observable biological effect. Welshons and colleagues (38) describe how hormone concentration influences receptor occupancy: "receptor occupancy is never determined to be linear in relation to hormone concentration . . . At concentrations above the K_d [the dissociation constant for receptor-ligand binding kinetics], saturation of the response occurs first, and then at higher concentrations, saturation of receptors is observed." What this means is that at low doses of hormone, a 10-fold increase in hormone concentration can have a 9-fold increase in receptor occupancy, whereas at high doses of hormone, a 10-fold increase in hormone concentration produces a less than 1.1-fold increase in receptor occupancy (38) (Fig. 1B). Thus, even moderate changes in hormone concentration in the low-dose range can produce substantial changes in receptor occupancy and therefore generate significant changes in biological effects. Welshons *et al.* (38) also note that a near-maximum biological response can be observed without a high rate of receptor occupancy, a situation that was previously termed the spare receptor hypothesis (110, 111); that is, the response mechanism saturates before all of the receptors are saturated. The presence of spare receptors is the basis for saying that these receptor systems are tuned to detect low concentrations that lead to occupancy of 0.1–10% of total receptors. Within this range of low receptor occupancy, there is high proportionality between changes in the free hormone concentration and changes in receptor occupancy, and a change in receptor occupancy by a ligand for the receptor is required to initiate changes in receptor-mediated responses (38).

There are additional reasons why natural hormones are active at low doses: 4) hormones have a strong affinity for their receptors (relative to affinity for other receptors) because many hormones are secreted from a single gland or site in the body but must have effects throughout the body in multiple tissues and 5) blood concentrations of hormones are normally pulsatile in nature, with the release of one hormone often controlled by the pulsatile release of another hormone (112, 113), and both the frequency and the amplitude of pulses modulate the biological response; hormones are also influenced by circadian rhythms, with dramatic differences in hormone secretion depending on the time of day (114, 115).

For many years, the mechanisms by which some environmental chemicals acted at low doses were not well understood. In 1995, the National Research Council appointed the Committee on Hormonally Active Agents in the Environment to address public concerns about the potential for adverse effects of EDCs on human health (116). At the time, work on understanding the mechanisms by which EDCs exert their effects was in its infancy, and in the executive summary, the committee stated, "Lack of knowledge about a mechanism does not mean that a reported effect is unconfirmed or unimportant, nor does demonstration of a mechanism document that the resulting effects are unique to that mechanism or are pervasive

Figure 1.

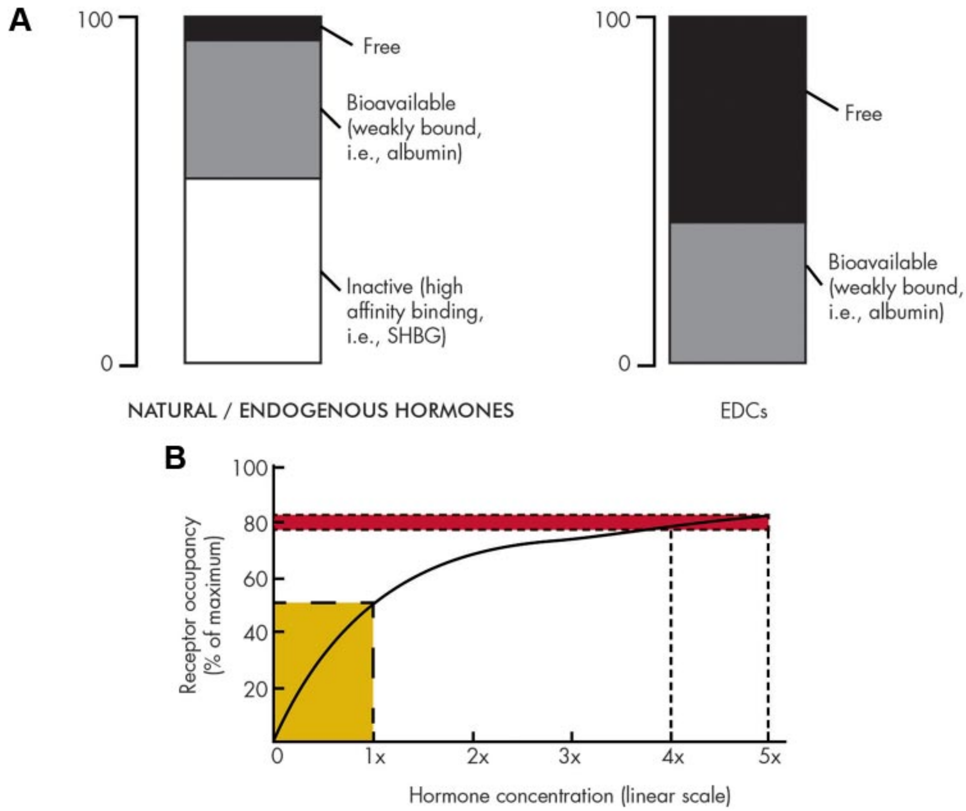

Figure 1. Characteristics and activities of natural hormones. A, This schematic depicts a typical relationship of three phases of circulating hormones: free (the active form of the hormone), bioavailable (bound weakly to proteins such as albumin), and inactive (bound with high affinity to proteins such as SHBG). These three phases act as a buffering system, allowing hormone to be accessible in the blood, but preventing large doses of physiologically active hormone from circulating. With EDCs, there may be little or no portion maintained in the inactive phase. Thus, the entirety or majority of a circulating EDC can be physiologically active; the natural buffering system is not present, and even a low concentration of an EDC can disrupt the natural balance of endogenous hormones in circulation. B, Schematic example of the relationship between receptor occupancy and hormone concentration. In this theoretical example, at low concentrations, an increase in hormone concentration of x (from 0 to 1x) causes an increase in receptor occupancy of approximately 50% (from 0 to 50%, see *yellow box*.) Yet the same increase in hormone concentration at higher doses (from 4x to 5x) causes an increase in receptor occupancy of only approximately 4% (from 78 to 82%, see *red box*).

in natural systems." Since that time, a tremendous amount of work has been dedicated to understanding the molecular mechanisms of action of EDCs, and in particular the mechanisms responsible for low-dose effects.

1. General mechanisms for EDC action

As discussed above, the endocrine system evolved to function when unbound physiologically active ligands (hormones) are present at extremely low doses (117). Because of shared receptor-mediated mechanisms, EDCs that mimic natural hormones have been proposed to follow the same rules and therefore have biological effects at low doses (38, 118). Similarly, EDCs that influence in any way the production, metabolism, uptake, or release of hormones also have effects at low doses, because even small changes in hormone concentration can have biologically important consequences (38, 119).

The estrogen-response mechanisms have been extensively studied with regard to the effects of endogenous estrogens and estrogenic drugs. In classical, genomic estrogen action, when endogenous estrogens bind to ER, those receptors bind to estrogen response element sequences or to a number of other response element sites adjacent to the genes directly responsive to estrogens; this binding influences transcription of estrogen-sensitive genes (120). Xenoestrogens produce the same reactions; these chemicals bind to ERs, which then initiate a cascade of molecular effects that ultimately modify gene expression. Therefore, for the actions of estrogenic EDCs, molecular mechanisms and targets are already known in some detail. Similar mechanisms are induced by the binding of androgens to the androgen receptor, or thyroid hormone agonists to the thyroid hormone receptor, among others.

Additionally, there are EDCs that act as antagonists of these hormone systems, binding to a receptor, but not activating the receptor's typical response, and preventing the binding or activity of the endogenous ligand. Finally, many EDCs bind to the receptor and trigger a response that is not necessarily the same as that triggered by the endogenous estrogens; these are termed selective ER modulators (SERMs). Ultimately, all of these actions occur at the level of the receptor.

Many studies have been dedicated to the understanding of which EDCs bind to which nuclear hormone receptors and how the binding affinities compare to the natural steroid. Thus, many of these chemicals have been classified as weak hormones. Yet studies have shown that, for example, the so-called weak estrogens like BPA can be equally potent as endogenous hormones in some systems, causing biological effects at picomolar levels (30, 38, 41, 121). Both endogenous estrogens and EDCs can bind to ER associated with the cell membrane [membrane-associated ER (mER)α and mERβ] that are identical to the nuclear ER (122–124), and a transmembrane ER called G-protein coupled receptor 30 that is structurally dissimilar to the nuclear ER and encoded by a distinct gene (125, 126). In many cells, 5–10% of total ERα and ERβ are localized to the plasma membrane (124); these membrane-associated receptors are capable of nongenomic steroid action in various cell types (30, 121, 127); thus, rapid and potent effects are well documented for many EDCs including BPA, DES, endosulfan, dichlorodiphenyldichloroethylene (DDE), dieldrin, and nonylphenol, among others (41, 128–130).

Finally, EDCs have other effects that are not dependent on binding to either classical or membrane-bound steroid hormone receptors. EDCs can influence the metabolism of natural hormones, thus producing differences in the amount of hormone that is available for binding either because more (or less) hormone is produced than in a typical system or because the hormone is degraded faster (or slower) than is normal. Other EDCs influence transport of hormone, which can also change the amount of hormone that is available for receptor binding. And EDCs can also have effects that are independent from known endocrine actions. One example is the effect of endogenous hormones and EDCs on ion channel activity. BPA, dichlorodiphenyltrichloroethane (DDT), DES, nonylphenol, and octylphenol have all been shown to disrupt Ca^{2+} channel activity and/or Ca^{2+} signaling in some cell types (131–134). This example illustrates how both natural hormones and EDCs can have hormonal activity via binding to nuclear hormone receptors but may also have unexpected effects via receptor-mediated actions outside of the classical endocrine system.

2. Mechanisms of EDC-induced low-dose actions

The various mechanisms by which EDCs act *in vitro* and *in vivo* provide evidence to explain how these chemicals induce effects that range from altered cellular function, to abnormal organ development, to atypical behaviors. Just as natural hormones display nonlinear relationships between hormone concentration and the number of bound receptors, as well as between the number of bound receptors and the maximal observable biological effect, EDCs obey these rules of binding kinetics (38). Thus, in a way, EDCs exploit the highly sensitive endocrine system and produce significant effects at relatively low doses.

To gain insight into the effects of natural hormones and EDCs on gene expression profiles, it is possible to calculate doses that produce the same effect on proliferation of cultured cells, *i.e.* the quantitative cellular response doses, and determine the effect of those doses on transcriptomal signature profiles. When this is done for estradiol and EDCs with estrogenic properties, the affected estrogen-sensitive genes are clearly different (135). However, an interesting pattern emerges: comparing profiles among only the phytoestrogens shows striking similarities in the genes up- and down-regulated by these compounds; profile comparisons between only the plastic-based estrogens also show similarities within this group. Yet even more remarkable is what occurs when the doses are selected not based on cell proliferation assays but instead on the ability of estradiol and estrogen-mimics to induce a single estrogen-sensitive marker gene. When doses were standardized based on marker gene expression, the transcriptomal signature profiles were very similar between estradiol and estrogen mimics (135). Taken together, these results suggest that the outcomes of these experiments are contextual to the normalization parameter and that marker gene expression and cell proliferation are not superimposable. This indicates that the biological level at which the effects of chemicals are examined (*i.e.* gene expression, cellular, tissue, organ, or organismal) can greatly impact whether low-dose effects are observed and how these effects are interpreted.

There are several other mechanisms by which low-dose activities have been proposed. One such possibility is that low doses of EDCs can influence the response of individuals or organs/systems within the body to natural hormones; thus, the exposed individual has an increased sensitivity to small changes in endogenous steroids, similar to the effects of intrauterine position (see Ref. 136 and *Section I.F*). In fact, several studies have shown that exposure to EDCs such as BPA during perinatal development can influence the response of the mammary gland to estrogen (137, 138) and the prostate to an estrogen-testosterone mixture similar to the concentrations produced in aging men (139–142). There is also evidence that EDCs work additively or even synergistically with other chemicals and natural hormones in the body (143–145). Thus, it is plausible that some of the low-dose effects of an EDC are actually effects of that exogenous chemical plus the effects of endogenous hormone.

Finally, it should be noted that during early development, the rodent fetus is largely, but not completely (146), protected from estrogen via the binding activity of α-fetoprotein, a plasma protein produced in high levels by the fetal liver (147). Some estrogen-like EDCs, however, bind very weakly to α-fetoprotein, and therefore, it is likely that this protein does not provide protection to the fetus during these sensitive developmental periods (36, 148). Furthermore, because EDCs may not bind to α-fetoprotein or other high-affinity proteins in the blood (148–150) and can have a higher binding affinity to proteins like albumin (compared with natural estrogens) (36, 149), the balanced buffer system in place for endogenous hormones may be disturbed (Fig. 1A). Thus, whereas only a portion of endogenous hormones are bioavailable, the entirety of a circulating EDC could be physiologically active.

The effects of hormones and EDCs are dependent on dose, and importantly, low (physiological) doses can be more effective at altering some endpoints compared with high (toxicological) doses. There are many well-characterized mechanisms for these dose-specific effects including signaling via single *vs.* multiple steroid receptors due to nonselectivity at higher doses (30), receptor down-regulation at high doses *vs.* up-regulation at low doses (151, 152), differences in the receptors present in various tissues (153, 154), cytotoxicity at high doses (155), and tissue-specific components of the endocrine-relevant transcriptional apparatus (104, 105). Some of these factors will be addressed in *Section III.B* in the section dedicated to NMDRCs.

F. Intrauterine position and human twins: examples of natural low-dose effects

Hormones have drastically different effects at different periods of development. In a now classical *Endocrinology* paper, Phoenix and colleagues (156) showed that hormone exposures during early development, and in particular fetal development, had organizational effects on the individual, whereby the developing organs were permanently reorganized by exposure to steroids. Permanent, nonreversible masculinization of the developing body plan by androgen exposure *in utero* is an example. These organizational effects are in contrast to the effects of the same hormones, at similar or even higher doses, on adults. The effects of steroids on individuals after puberty have been termed activational, because the effects on target organs are typically transient; withdrawal of the hormone returns the phenotype of the individual to the preexposed state (157), although this is not always the case (158).

One of the most striking examples of the ability of low doses of hormones to influence a large repertoire of phenotypes is provided by the study of intrauterine positioning effects in rodents and other animals. The rodent uterus in particular, where each fetus is fixed in position along a bicornate uterus with respect to its neighbors, is an excellent model to study how hormones released from neighboring fetuses (159) can influence the development of endocrine-sensitive endpoints (31). Importantly, differences in hormonal exposures by intrauterine position are relatively small (see Fig. 2) (160). Thus, even a small magnitude in differences of hormonal exposures is sufficient to generate effects on behavior, physiology, and development.

The earliest studies of intrauterine position compared behavioral characteristics of females relative to their position in the uterus (161–164); male behavior was also affected by intrauterine position (161, 165–167). Subsequent studies of intrauterine position showed that position in the uterus influenced physiological endpoints (157, 160–162, 168–174) as well as morphological endpoints in female rodents (160, 161, 163, 164, 175–177). Male physiology and morphological endpoints were similarly affected by intrauterine position (165, 167, 177–179).

The endocrine milieu of the uterine environment has been implicated in these effects because differences in hormonal exposure have been observed based on intrauterine position (Fig. 2). The production of testosterone in male mice starting at approximately d 12 of gestation allows for passive transfer of this hormone to neighboring fetuses (159, 160, 180). Thus, fetuses positioned between two male neighbors have slightly higher testosterone exposures compared with fetuses positioned between one male and one female or two female neighbors (168, 181–183). These data indicate that very small differences in hormone exposures during fetal development are capable of influencing a variety of endpoints, many of which become apparent only during or after puberty. Furthermore, small differences in hormone exposures may be compounded by other genetic variations such as those normally seen in human populations.

Intrauterine effects have been observed in animals with both large litters and singleton or twin births including ferrets, pigs, hamsters, voles, sheep, cows, and goats (136, 184, 185). But perhaps the most compelling evidence for intrauterine effects comes from human twin studies. Many

Figure 2.

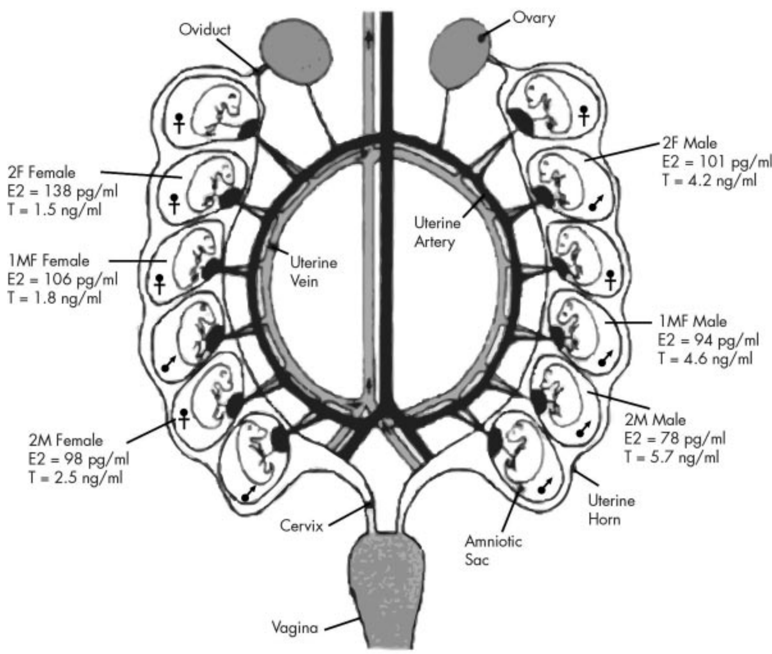

Figure 2. Intrauterine position produces offspring with variable circulating hormone levels. Fetuses are fixed in position in the bicornate rodent uterus, thus delivery via cesarean section has allowed for study of the influence of intrauterine position on behaviors, physiology, and organ morphology. Illustrated here are the differences in estradiol (E2) and testosterone (T) concentrations measured in male and female fetuses positioned between two male neighbors (2M), two female neighbors (2F), or neighbors of each sex (1MF). Direction of blood flow in the uterine artery (dark vessel) and vein (light vessel) is indicated by an *arrow* (159).

studies have found that the sex of the fetuses impacts the phenotype of one or more of the twins, with significant evidence suggesting that male twins strongly influence a female co-twin; endpoints including sensation seeking (186), ear superiority (187, 188), brain and cerebellum volume (189), masculine/feminine behaviors and aggression levels (190–192), handedness (193, 194), reproductive fitness (192, 195), finger length ratios (196), risk for developing eating disorders (197), and birth weight (198) were all affected in females with a male twin. From these studies, many authors have concluded that testosterone from male fetuses influences developmental parameters in female twins; typically, male same-sex twins do not display altered phenotypes for these endpoints. Yet importantly, limited studies indicate that female twins can influence their uterine pairs, with some behaviors affected in male co-twins (191); breast cancer incidence in women and testicular cancer in men have also been shown to be influenced by having a female co-twin (83, 199, 200).

Although the mechanisms for these intrauterine effects are not completely understood, very small differences in hormone exposures have been implicated, making the effects of twin gestations a natural example of low-dose phenomena. In the human fetus, the adrenals produce androgens that are converted to estrogen by the enzyme aromatase, specifically in the placenta. In a human study designed to compare hormone levels in the amniotic fluid, maternal serum, and umbilical cord blood of singleton male and female fetuses, significant differences were observed in the concentrations of testosterone, androstenedione (A4), and estradiol (201). Specifically, amniotic fluid concentrations of testosterone and A4 were approximately twice as high in male fetuses, whereas estradiol concentrations were slightly, but significantly, higher in female fetuses. Yet, interestingly, there were no differences for any of the hormones in maternal serum, similar to findings in mice that litters with a high proportion of males or females did not impact testosterone, estradiol, or progesterone serum levels in mothers (180). In umbilical cord serum, concentrations of A4 and estradiol were higher in males compared with females (201), although it must be noted that these samples were collected at parturition, long after the fetal period of sexual differentiation of the reproductive organs.

Several studies have specifically compared steroid hormone levels in maternal and umbilical cord blood samples collected from same-sex and opposite-sex twins. Male twins, whether their co-twin was a male or a female, had higher blood concentrations of progesterone and testosterone compared with female twins (202). Furthermore, for both sexes, dizygotic twins had higher levels of these hormones, as well as estradiol, compared with monozygotic twins. Fetal sex had no effect on maternal concentrations of testosterone, progesterone, or estrogen, suggesting that any differences observed in fetal samples are due to contributions from the fetuses' own endocrine systems and the placental tissue (203). Yet an additional study conducted in women carrying multiple fetuses (more than three) indicates that both estradiol and progesterone concentrations in maternal plasma increase with the number of fetuses, and when fetal reduction occurs, these hormone levels remain elevated (204).

It has been proposed that low-dose effects seen in different intrauterine positions in litter-bearing animals could be an evolutionary adaptation, whereby the genotypes of the fetuses are relatively similar but a range of phenotypes can be produced via differential hormone exposures (136, 168). For example, female mice positioned between two females are more docile and thus have better reproductive success when resources are plentiful, but females positioned between two males are more aggressive and therefore are more successful breeders under stressful conditions (161, 171, 175). In this way, a mother produces offspring with variable responses to environmental conditions, increasing the chances that her own genetic material will continue to be passed on. Yet although there is evidence to suggest that a variable intrauterine environment is essential for normal development (171), intrauterine positional effects appear to have little effect on offspring phenotypes in inbred rodent strains (168, 205). This result may be related to the link between genetic diversity and hormone sensitivity (206, 207), suggesting that outbred strains are the most appropriate for studying endocrine endpoints and are also most similar to the effects of low doses of hormones on human fetuses.

Finally, it has been proposed that similar mechanisms are used by the developing fetus in response to natural hormones via intrauterine position and EDCs with hormonal activity (136). To this end, several studies have examined the effects of both exposure to an EDC and intrauterine position or have considered the effect of intrauterine position on the response of animals to these chemicals (174, 176, 181, 208, 209). For example, one study found that intrauterine position affected the morphology of the fetal mammary gland, yet position-specific differences were obliterated by BPA exposure (176). Additional studies suggest that prostate morphology is disrupted by 2,3,7,8-tetrachlorodibenzo-*p*-dioxin (TCDD) exposure in males positioned between two females, but this chemical does not affect prostate morphology in males positioned between two males (181). Finally, male rodents positioned between two males have higher glucose intolerance than males positioned between two females, yet when these males are given a diet high in phytoestrogens, glucose tolerance is dramatically improved in the males positioned between two males, whereas their siblings positioned between two females do not benefit (209). What is clear from these studies is that low doses of natural hormones are capable of altering organ morphology, physiology, and reproductive development, similar to the effects of EDCs.

It has been suggested that the endocrine system allows for homeostatic control and that the aim of the endocrine system is to "maintain normal functions and development in the face of a constantly changing environment" (210). Yet studies from intrauterine position, together with studies of EDCs (see *Sections II.C–F*), clearly indicate that the fetal endocrine system cannot maintain a so-called homeostasis and is instead permanently affected by exposures to low doses of hormones.

II. Demonstrating Low-Dose Effects Using a WoE Approach

A. Use of a WoE approach in low-dose EDC studies

In 2001, the NTP acknowledged that there was evidence to support low-dose effects of DES, genistein, methoxychlor, and nonylphenol (2). Specifically, the NTP expert panel found that there was sufficient evidence for low-dose effects of DES on prostate size; genistein on brain sexual dimorphisms, male mammary gland development, and immune responses; methoxychlor on the immune system; and nonylphenol on brain sexual dimorphisms, thymus weight, estrous cyclicity, and immune responses. Using the NTP's definitions of low dose (*i.e.* effects occurring in the range of typical human exposures or occurring at doses lower than those typically used in standard testing protocols), we propose that most if not all EDCs are likely to have low-dose effects. Yet an important caveat of that statement is that low-dose effects are expected for particular endpoints depending on the endocrine activity of the EDC, and not for any/all endocrine-related endpoints. For example, if a chemical blocks the synthesis of a hormone, blood levels of the hormone are expected to decline, and the downstream effects should then be predicted from what is known about the health effects of low hormone levels. In contrast, if a chemical binds a hormone receptor, the effects are expected to be very complex and to be both tissue specific and dose specific. Finally, most EDCs interact with multiple hormone pathways, or even multiple hormone receptors, making the expected effects even more complex and context specific (211–213).

Table 3 summarizes a limited selection of chemicals that have evidence for low-dose effects, with a focus on *in vivo* animal studies. As seen by the results presented in this table, low-dose effects have been observed in chemicals from a number of classes with a wide range of uses including natural and synthetic hormones, insecticides, fungicides, herbicides, plastics, UV protection, and other industrial processes. Furthermore, low-dose effects have been observed in chemicals that target a number of endocrine endpoints including many that act as estrogens and antiandrogens as well as others that affect the metabolism, secretion, or synthesis of a number of hormones. It is also clear from this table that the cutoff for low-dose effects is not only chemical specific but also can be effect dependent. And finally, although this table is by no means comprehensive for all EDCs or even the low-dose effects of any particular chemical, the affected endpoints cover a large range of endocrine targets.

Several EDCs have been well studied, and the number of publications focusing on low-dose effects on a particular developmental endpoint is high; however, other

TABLE 3. EDCs with reported low-dose effects in animals (or humans, where stated)

Chemical	Use	EDC action	Low-dose cutoff	Affected endpoint	Refs.
Aroclor 1221 (PCB mixture)	Coolants, lubricants, paints, plastics	Mimics estrogens, antiestrogenic activity, *etc.*	0.1–1 mg/kg (produces human blood levels)	Brain sexual dimorphisms	683, 684
Atrazine	Herbicide	Increases aromatase expression	200 μg/liter (334, 335)	Male sexual differentiation/development	See this review
BPA	Plastics, thermal papers, epoxy resins	Binds ER, mER, ERRγ, PPARγ, may weakly bind TH receptor and AR	400 μg/kg · d (produces human blood concentrations)	Prostate, mammary gland, brain development and behavior, reproduction, immune system, metabolism	See this review
Chlordane	Insecticide	Binds ER	100 ng/g (produces human blood levels)	Sexually dimorphic behavior	685
Chlorothalonil	Fungicide, wood protectant	Aromatase inhibitor	164 μg/liter (environmental concentrations, EPA)	Corticosterone levels (amphibians)	686
Chlorpyrifos	Insecticide	Antiandrogenic	1 mg/kg · d (EPA)	Acetylcholine receptor binding (brain)	687
DDT	Insecticide	Binds ER	0.05 mg/kg (EPA)	Neurobehavior	688
DES	Synthetic hormone	Binds ER	0.3–1.3 mg/kg · d (dose typically administered to pregnant women)	Prostate weight	689
Dioxin (TCDD)	Industrial byproduct	Binds AhR	1 μg/kg · d (397)	Spermatogenesis, immune function and oxidative stress, tooth and bone development, female reproduction, mammary gland, behavior	See this review
Genistein	Phytoestrogen	Binds ER	50 mg/kg (EPA)	Brain sexual dimorphisms	690
Heptachlor	Insecticide	Induces testosterone hydroxylases	0.15 mg/kg · d (EPA)	Immune responses	691
Hexachlorobenzene	Fungicide	Modulates binding of ligand to TRE, weakly binds AhR	0.08 mg/kg · d (EPA)	Anxiety and aggressive behaviors	692
Maneb	Fungicide	Inhibits TSH release, may bind PPARγ	5 mg/kg · d (EU Commission)	Testosterone release	693
Methoxychlor	Insecticide	Binds ER	5 mg/kg · d (WHO)	Immune system	694, 695
4-Methylbenzylidine camphor	UV screen	Weakly estrogenic	10 mg/kg · d (Europa)	Sexual behavior	696
Methyl paraben	Preservative	Estrogenic	1000 mg/kg · d (EFSA)	Uterine tissue organization	697
Nicotine	Natural alkaloid in tobacco	Binds acetylcholine receptors, stimulates epinephrine	Human use of nicotine substitutes	Incidence of cryptorchidism (humans)	698
Nonylphenol	Detergents	Weakly estrogenic	15 mg/kg · d (EPA)	Testosterone metabolism	699
Octylphenol	Rubber bonding, surfactant	Weakly binds ER, RXR, PRGR	10 mg/kg · d (700)	Testes endpoints	701
Parathion	Insecticide		0.2 mg/kg · d (WHO)	Cognitive and emotional behaviors	702
PBDE-99	Flame retardant	Alters TH synthesis	0.3 mg/kg · d (EPA)	TH levels in blood	703
PCB180	Industrial lubricant, coolant	Impairs glutamate pathways, mimics estrogen	Examined normal human populations	Diabetes (humans)	704
PCB mixtures	Coolants, lubricants, paints, plastics	Binds AhR, mimic estrogens, antiestrogenic activity, etc.	Each at environmentally relevant levels	TH levels	705
Perchlorate	Fuel, fireworks	Blocks iodide uptake, alters TH	0.4 mg/kg · d (436)	TSH levels (humans)	See this review
Sodium fluoride	Water additive (to prevent dental caries), cleaning agent	Inhibits insulin secretion, PTH, TH	4 mg/liter water (EPA standard)	Bone mass and strength	706
Tributyltin oxide	Pesticide, wood preservation	Binds PPARγ	0.19 mg/kg · d (EPA)	Obesity	707
Triclosan	Antibacterial agent	Antithyroid effects, androgenic and estrogenic activity	12 mg/kg · d (Europe SCCP)	Altered uterine responses to ethinyl estradiol	708
Vinclozolin	Fungicide	Antiandrogenic	1.2 mg/kg · d (EPA)	Male fertility	709

EDC action indicates that for some chemicals, an effect is observed (*i.e.* estrogenic, androgenic), but for many EDCs, complete details of receptor binding are unavailable or incomplete. Low-dose cutoff means the lowest dose tested in traditional toxicology studies, or doses in the range of human exposure, depending on the data available. Affected endpoint means at least one example of an endpoint that shows significant effects below the low-dose cutoff dose. This list is not comprehensive, and the lack of an endpoint on this table does not suggest that low doses do or do not affect any other endpoints. AR, Androgen receptor; EFSA, European Food Safety Authority; ERR, estrogen related receptor; PCB, polychlorinated biphenyl; PPARγ, peroxisome proliferator-activated receptor-γ; PRGR, progesterone receptor; RXR, retinoid X receptor; SCCP, Scientific Committee on Consumer Products; TH, thyroid hormone; TRE, thyroid response element; WHO, World Health Organization.

chemicals are less well studied with fewer studies pointing to definitive low-dose effects on a given endpoint. In fact, there are a significant number of EDCs for which high-dose toxicology testing has been performed and the no observed adverse effect level (NOAEL) has been derived, but no animal studies in the low-dose range have been conducted, and several hundred additional EDCs where no significant high- or low-dose testing has been performed (see Table 4 for examples). Balancing the large amount of data collected from some well-studied chemicals like BPA and atrazine with the relative paucity of data about other chemicals is a difficult task.

TABLE 4. Select examples of EDCs whose potential low-dose effects on animals remain to be studied

Chemical	Use	EDC action	Low-dose cutoff
Antiseptics and preservatives			
Butyl paraben	Preservative (cosmetics)	Estrogenic, antiandrogenic	2 mg/kg · d (EPA)
Propyl paraben	Antimicrobial preservative found in pharmaceuticals, foods, cosmetics, and shampoos	Estrogenic activity	LOAEL 10 mg/kg · d, NOEL 6.5 mg/kg · d (Europa)
Cosmetics and personal care products			
2,4-Dihydroxybenzophenone	UV absorber in polymers, sunscreen agent	Estrogenic activity	Not identified
3-Benzylidene camphor	UV blocker used in personal care products	Estrogenic activity	0.07 mg/kg · d (710)
4,4′-Dihydroxybenzophenone	UV light stabilizer used in plastics, cosmetics, adhesives, and optical fiber	Estrogenic activity	Not identified
Benzophenone-2	Used in personal care products such as aftershave and fragrances	Estrogenic activity, changes in T_4, T_3, and TSH levels, alterations in cholesterol profile	NOEL 10–333 mg/kg · d (711)
Benzophenone-3	UV filter	Estrogenic, PPARγ activator	200 mg/kg · d (Europa)
Multiple use (other)			
Melamine	Flame-retardant additive and rust remover; used to make laminate, textile, and paper resins; metabolite of cyromazine	Affects voltage-gated K^+ and Na^+ channels and Ca^{2+} concentrations in hippocampal neurons	63.0 mg/kg · d (FDA)
Resorcinol	Used in the manufacturing of cosmetics, dyes, flame retardants, hair dye formulations, pharmaceuticals, skin creams, and tires	Alters T_4 and TSH levels	80.00 mg/kg · d (Europa)
Pesticides			
Aldrin[a]	Insecticide	Estrogenic activity	0.025 mg/kg · d (Health Canada)
Alachlor	Herbicide	Decreases serum T_4, binds PR, weakly binds ER	1 mg/kg · d (EPA)
Amitrole	Herbicide	Decreases thyroid hormone	0.12 mg/kg · d (FAO)
Bitertanol	Fungicide	Alters aromatase	30 mg/kg · d (EPA)
Carbendazim	Fungicide	Affects FSH, LH, and testosterone levels; alters spermatogenesis and Sertoli cell morphology	8 mg/kg · d (712)
Diazinon	Insecticide	Alters glucocorticoids	0.065 mg/kg · d (CDC)
Endrin[a]	Insecticide	Stimulates glucocorticoid receptor	0.025 mg/kg · d (CDC)
Fenoxycarb	Insecticide	Alters acetylcholinesterase	260 mg/kg · d (CDC)
Mirex[a]	Insecticide	Decreases testosterone levels	0.075 mg/kg · d (CDC)
Zineb	Fungicide	Alters T_4 and dopamine levels	LOAEL 25 mg/kg · d (EPA)
Ziram	Fungicide	Alters norepinephrine levels	1.6 mg/kg · d (EPA)
Resins			
Bisphenol F	Used in polycarbonates	Alters T_4, T_3, and adiponectin levels, has estrogenic activity	LOAEL 20 mg/kg · d (713)
Styrene	Precursor to polystyrene	Alters dopamine	200 mg/kg · d (EPA)

PPARγ, peroxisome proliferator-activated receptor-γ; PR, progesterone receptor.

[a] These chemicals were identified in the 1990s as part of the dirty dozen, 12 chemicals that were acknowledged to be the worst chemical offenders because of their persistence in the environment, their ability to accumulate through the food chain, and concerns about adverse effects of exposures to wildlife and humans. These chemicals were banned by the Stockholm convention and slated for virtual elimination. Yet there is still very little known about the low-dose effects of these chemicals, likely in the range of past and current human and/or wildlife exposures.

WoE approaches have been used in a large number of fields to determine whether the strength of many publications viewed as a whole can provide stronger conclusions than any single study examined alone. Although the term, weight of evidence, is used in public policy and the scientific literature, there is surprisingly little consensus about what this term means or how to characterize the concept (214). Historically, risk assessors have used qualitative approaches (*i.e.* professional judgment to rank the value of different cases) and quantitative approaches (*i.e.* scoring methods to produce statistical and mathematical determinations of chemical safety), but it has been argued that these methods lack transparency and may produce findings that are unrepeatable from one risk assessor to another (215, 216). Whatever the method used, when EDCs are being assessed, it is important to use the principles of endocrinology to establish the criteria for a WoE approach. We do this in *Section II.B*, identifying three key criteria for determining whether a study reporting no effect should be incorporated into a WoE approach. It also should be noted that in epidemiology, the term, weight of evidence, is typically not used, but the concept is actuated by meta-analysis, formally and quantitatively combining data across studies, including a plot of individual and pooled study findings and also a measure of heterogeneity of findings between studies.

For some well-studied chemicals, there are large numbers of studies showing both significant effects, and additional studies showing no effects, from low-dose exposures. In these cases, extensive work is needed to deal with discordant data collected from various sources; studies showing no effect of low-dose exposures must be balanced in some way with those studies that do show effects. As stated by Basketter and colleagues (217), "it is unwise to make a definitive assessment from any single piece of information as no individual assay or other assessment . . . is 100% accurate on every occasion . . . This means that from time to time, one piece of conflicting data has to be set aside." WoE approaches in EDC research have typically dealt with datasets that have some conflicting studies, and these conflicts are even more difficult to sort out when studies have attempted to directly replicate published findings of adverse effects (see for example Refs. 218–221).

Most previously published WoE analyses have examined chemicals broadly (asking questions such as, "Does BPA produce consistent adverse effects on any endpoint?") (see Ref. 222). This can lead to problems including those encountered by the NTP expert panel, which found that there was some evidence for low-dose effects of BPA on certain endpoints but mixed findings for other endpoints. For example, the panel noted that some studies found low-dose effects of BPA on the prostate, but other studies could not replicate these findings. In *Section II.B*, we address criteria that are needed to accept those studies that are unable to detect low-dose effects of chemicals; these criteria were not used by the NTP in 2001, but they are essential to address controversies of this sort and perform WoE analyses using the best available data. In the sections that follow, we employed a WoE approach to examine the evidence for low-dose effects of single chemicals on selected endpoints or tissues, also paying attention to when in development the EDC in question were administered.

B. Refuting low-dose studies: criteria required for acceptance of studies that find no effect

Over the past decade, a variety of factors have been identified as features that influence the acceptance of low-dose studies (69, 71, 76, 77, 90, 205, 223, 224). In fact, the NTP low-dose panel itself suggested that factors such as strain differences, diet, caging and housing conditions, and seasonal variation can affect the ability to detect low-dose effects in controlled studies (2). In particular, three factors have been identified; when studies are unable to detect low-dose effects, these factors must be considered before coming to the conclusion that no such effects exist.

1. Negative controls confirm that the experimental system is free from contamination

Although all scientific experiments should include negative (untreated) controls, this treatment category is particularly important for EDC research. When a study fails to detect low-dose effects, the observed response in control animals should be compared with historical untreated controls; if the controls deviate significantly from typical controls in other studies, it may indicate that these animals were, in fact, treated or contaminated in some way or that the endpoint was not appropriately assessed (77, 205, 225). For example, if an experiment was designed to measure the effect of a chemical on uterine weight, and the control uteri have weights that are significantly higher than is normally observed in the same species and strain, these animals may have been inadvertently exposed to an estrogen source, or the uteri may not have been dissected properly by the experimenters. In either case, the study should be examined carefully and likely cannot be used to assess low-dose effects; of course, untreated controls should be monitored constantly because genetic drift and changes in diet and housing conditions can also influence these data, thus explaining changes from historical controls. Importantly, several types of contamination have been identified in studies of EDCs including the leaching of chemicals from caging or other environmental sources (226, 227), the use of pesticide-contaminated control sites for wildlife studies and contaminated controls in laboratory studies (76), and even the use of food that interferes with the effects of EDCs (224, 228). It is also important to note that experiments must consider the solvent used in the administration of their test chemical, and thus good negative controls should test for effects of the solvent itself. Using solvent negative controls helps prevent false positives as well as the possibility that the vehicle could mask the effects of the chemical being studied.

2. Positive controls indicate that the experimental system is capable of responding to low doses of a chemical acting on the same pathway

Many studies do not include a positive control, either because of the size and cost of the experiment when including an additional treatment or because an appropriate positive control has not been identified for the endpoint being examined. If the experiment detects an effect of the chemical in question, the exclusion of a positive control does not necessarily affect the interpretation of the results; instead, it can be appropriately concluded that the test chemical is significantly different from unexposed (but similarly handled/treated) negative controls. However, if the study fails to detect low-dose effects of a test chemical, no convincing conclusion can be made; in this case, a positive control is required to demonstrate that the experimental system was capable of detecting such effects (71, 75, 77, 205).

Several issues must be considered when addressing whether the positive control confirms the sensitivity of the assay. First, an appropriate chemical must be selected, and it must be administered via the appropriate route, *i.e.* if the test chemical is administered orally, a positive control that is orally active, such as ethinyl estradiol, should be used; if the test chemical is administered sc, a positive control that is active via this route, such as 17β-estradiol, is most appropriate. The use of 17β-estradiol in studies that use oral exposures is particularly inappropriate (see Ref. 229) for example) because this hormone, like most natural steroids, has very low oral activity (77). Second, the positive control chemical must be examined, and effective, at appropriately low doses. Thus, if the test chemical is 100 times less potent than the positive control, a dose of the positive control 100 times lower than the test compound must produce effects (69, 71, 205). For example, studies that report effects of ethinyl estradiol only at doses that are hundreds of times higher than the dose that is effective in contraceptives (230) are not capable of detecting low-dose effects of test chemicals. Without appropriate and concurrent positive and negative controls, studies that fail to detect low-dose effects of test chemicals should be rejected.

3. Species and animal strains that are responsive to EDCs must be used

The NTP expert panel specifically noted that "because of clear species and strain differences in sensitivity, animal-model selection should be based on responsiveness to endocrine-active agents of concern (*i.e.* responsive to positive controls), not on convenience and familiarity" (2). An analysis of the BPA literature clearly showed that many of the studies that failed to detect effects of low doses used the Charles River Sprague-Dawley rat (75); this strain was specifically bred to have large litters (231), and many generations of inbreeding have rendered the animal relatively insensitive to estrogens (205). The NTP expert panel noted the lack of effects of BPA on Sprague-Dawley rats and concluded that there were clear differences in strain sensitivity to this chemical (2). Importantly, this may not be true for Sprague-Dawley rats that originate from other vendors, indicating that animal origin can also influence EDC testing.

Many studies in mice (138, 206, 207, 232–234) and rats (232, 235–239) have described differences displayed between two (or more) animal strains to a natural hormone or EDC. Often these differences can be traced to whether a strain is inbred or outbred. Genetically diverse strains are generally found to be more sensitive to estrogens (206). Importantly, well-controlled studies demonstrate that strain differences in response to estrogen treatment may be organ dependent or may even differ between levels of tissue organization within the same organ. For example, the Sprague-Dawley rat is more sensitive to ethinyl estradiol than other strains when measured by uterine wet weight. However, when other endpoints were measured, *i.e.* height of cells in the uterine epithelium, the Sprague-Dawley rat was indistinguishable from the DA/Han rat; instead, the Wistar rat had the most heightened response (237). Additionally, there are data to indicate that strain differences for one estrogen may not be applicable for all estrogenic chemicals. In comparing the responses of DA/Han, Sprague-Dawley, and Wistar rats to other xenoestrogens, additional differences were observed including a greater increase in uterine wet weight of DA/Han and Sprague-Dawley rats but not Wistar rats after exposure to 200 mg/kg BPA; increased uterine epithelium thickness was observed in Wistar and Sprague-Dawley rats but not DA/Han rats after exposure to 200 mg/kg octylphenol (237). Attempts have been made, at times successfully, to map the differences in strain response to genetic loci (240). However, it appears that strains with differences in response that manifest in some organs do not have divergent responses in other organs, a phenomenon that is not explained by genetic differences alone. For these reasons, the NTP's recommendation that scientists use animals that are proven responsive to EDCs (2) must be observed.

4. Additional factors?

Additional factors have also been identified as influential in the ability (or inability) to detect low-dose effects in

EDC studies. Although these factors must be considered when interpreting studies and using a WoE approach, some issues that were previously identified as essential factors in the design of studies (*i.e.* route of administration) have more recently been disputed (241).

The first factor is the use of good laboratory practices (GLP) in the collection of data. When assessing the EDC literature for risk assessment purposes, the FDA and European Food Safety Authority (EFSA) have given special prominence to studies that complied with GLP guidelines, essentially giving scientific priority to industry-funded studies because that group typically conducts GLP guideline studies (33, 242). Because GLP guidelines are designed only to control data collection, standards for animal care, equipment, and facility maintenance, and they do not ensure that studies were designed properly with the appropriate controls, it has been argued that the use of GLP methods is not appropriate or required for EDC studies (69).

GLP studies are typically large, with dozens of animals studied for each endpoint and at each time point. Thus, it has been concluded that these studies are better simply because they are larger. Yet small studies designed with the use of power analysis, statistical tools that allow researchers to determine *a priori* the number of animals needed to determine significant differences based on effect size, are equally capable of detecting effects while reducing the number of animals used (69). GLP studies also typically (but not necessarily) rely upon standardized assays, which are not generally considered contemporary tools and are often shown to be incapable of detecting adverse effects on endpoints that employ modern tools from molecular genetics and related disciplines. Furthermore, some fields of EDC research have no GLP studies (243). Finally, there is no published evaluation of whether studies performed under GLP are more capable of providing accurate results. The priority given to GLP studies therefore does not appear to have been justified based on any comparative analysis. Thus, as long as studies include appropriate measures of quality assurance, they need not be performed under GLP standards to provide reliable and valuable information, and many GLP studies are inadequate to assess important and relevant endpoints. Instead, the most valuable studies consider the factors presented above, along with appropriate dose selections and choice of endpoint.

The second factor worth considering is the source of funding for studies. In several fields, significant controversy has been produced based on the results obtained from independent scientists compared with results obtained from scientists affiliated with the chemical industry (75, 76). Funding source *per se* should not dictate the outcome of a research study, but that does not mean that researchers are not subject to underlying biases. In our own WoE analyses, presented in *Sections II.C–G*, we do not discount studies merely because they were conducted with industry funds, nor do we lend higher weight to studies conducted in independent or government laboratories; if a study, regardless of funding, finds no effect of a chemical, it is given weight only if the three criteria described in *Sections II.B.1–3* (successful and appropriate negative and positive controls and appropriate choice of animal model) were met.

To perform a WoE evaluation, we identified some basic information about the chemical in question, the dose that would be considered a low-dose cutoff, and the studies in support of and against low-dose effects. We then considered whether the majority of studies found effects of low doses of a chemical on a single endpoint in question. If studies did not find low-dose effects, we considered whether they adhered to the criteria discussed above for proper design of an EDC low-dose study. In particular, we considered whether appropriate animal strains as well as positive and negative controls were used. With regard to animal strain, as discussed briefly in *Section II.B.3*, there is variability between animal strains that can significantly influence the ability to detect effects of EDCs; using insensitive strains to produce negative data cannot refute positive data in a sensitive strain. In several cases, it was easy to conclude that there was a strong case for low-dose effects because there were no studies finding no effects at low doses or because all of the negative studies were inappropriately designed. For other chemicals, a significant number of studies found effects on the endpoint being considered, but other (adequately designed) studies refuted those findings. Under those circumstances, we determined whether the findings of harmful effects came from multiple laboratories; when they did, we cautiously concluded that there was evidence for low-dose effects. Below (*Sections II.C–G*), we present five examples where a significant number of studies were available examining low-dose effects of an EDC on a single particular endpoint.

C. BPA and the prostate: contested effects at low doses?

As discussed briefly above, BPA is one of the best-studied EDCs, with more than 200 published animal studies, many of which focused on low doses (29, 31). The effects of this chemical on wildlife species have also been described in detail (28). BPA is found in a myriad of consumer products, and it leaches from these items under normal conditions of use (4). It has also been regularly detected in air, water, and dust samples. The majority of individuals in industrialized countries have BPA metabolites in their urine, and trends indicate increasing exposures in developing nations like China (87, 244). Although it was long suspected that most human exposures originate from BPA contamination of food and beverages, a study comparing the excretion of BPA metabolites with the length of time spent fasting suggests that there are also likely to be significant exposures from sources other than food and beverages (245). BPA has recently been shown to be used in large quantities in thermal and recycled papers and can enter the skin easily via dermal absorption (246–248). Thus, despite the large amount of information available on BPA sources, our understanding of how these sources contribute to total human exposures remains poor; these studies also point to significant gaps in current knowledge about BPA metabolism in humans (243).

BPA binds to the nuclear and membrane ER, and thus most of the effects of this chemical have been attributed to its estrogenic activity (27). However, there is evidence that it can activate a number of additional pathways, including thyroid hormone receptor, androgen receptor, as well as peroxisome proliferator-activated receptor-γ signaling pathways (249–252). The cutoff for a low dose has been set at several different concentrations depending on which studies and definitions are used (see Table 1). The EPA calculated a reference dose for BPA of 50 μg/kg · d based on a LOAEL of 50 mg/kg · d (38). More recent pharmacokinetic scaling experiments have estimated that exposures to approximately 400 μg/kg · d produce blood concentrations of unconjugated BPA in the range of human blood concentrations (4). Thus, for the two WoE analyses of the BPA literature we conducted, doses of 400 μg/kg · d or lower were considered low dose; pharmacokinetic studies from nonhuman primates support the appropriateness of this dose for approximating human exposure levels (253). Furthermore, because this dose is below the toxicological LOAEL, it is a conservative cutoff for low-dose studies (see Refs. 3 and 38 and Table 1).

One of the most well studied and hotly debated examples of a low-dose effect comes from the BPA literature; regulatory agencies and scientists have addressed several times whether low doses of BPA during fetal and perinatal development affect the rodent prostate (118, 205, 254, 255). In 1997, the first study on BPA and the prostate determined that fetal exposure to low doses (2 and 20 μg/kg · d administered orally to pregnant mice) increased the weight of the adult prostate compared with unexposed male offspring (256). Since that time, several additional studies have verified that prostate weight is affected by fetal exposure to similar low doses (257–259). Studies have also shown that low doses of BPA affect androgen receptor binding activity in the prostate (257), tissue organization, and cytokeratin expression in the gland (260–262) as well as the volume of the prostate and the number and size of dorsolateral prostate ducts (208). Several recent studies have also examined whether low doses of BPA (10 μg/kg · d) influence the incidence of adult-onset prostatic intraepithelial neoplasia (PIN) lesions. Perinatal BPA exposure, whether administered orally or sc to pups, increases the incidence of PIN lesions in response to a mixture of testosterone and estradiol in adulthood (139, 141, 263); this hormonal cocktail was designed to mimic the endocrine changes associated with aging in men that also typically accompany the onset of prostate cancer. In addition to the effects of BPA on PIN lesions, these low doses also produced permanent alterations in the epigenome of exposed males, with prostates displaying completely unmethylated sequences in genes that are hypermethylated in unexposed controls (140, 263). In examining these studies, although the same effects of BPA on the prostate were not observed in all studies, there is an obvious trend demonstrating that low doses of BPA during early development significantly affect several aspects of prostate development.

Since the initial report showing effects of low doses on the prostate, approximately nine studies, including several designed specifically to replicate the original positive study, have shown no effects of low doses on the prostate (264–272); every one of these studies examined the prostate weight, and Ichihara *et al.* (264) also examined the effects of BPA on PIN lesions (without hormonal treatment) and the response of the prostate to a chemical carcinogen. Three of these studies failed to include a positive control of any kind (264, 268, 270); three studies used DES as a positive control but found no effect from exposure to this potent xenoestrogen (265–267) (*i.e.* the positive control failed); another study used 17β-estradiol as a positive control, inappropriately administered orally, and found no effects of this hormone on the prostate (271); and two studies used an estrogenic positive control (ethinyl estradiol) and found effects from its exposure, but only at inappropriately high doses (269, 272). These two studies clearly showed that the positive control dose was too high, because rather than increase the weight of the prostate (as seen after low doses of estrogens in other studies), the positive control decreased the weight of the adult prostate (269, 272).

Although this topic was once considered controversial, using a WoE approach, it is clear that there is strong evidence in support of low-dose effects of BPA on the development of the prostate. The evidence clearly shows that several endpoints, including prostate weight, were affected in similar ways in multiple studies from several different labs at doses below 400 μg/kg · d; most effects were seen at doses below 50 μg/kg · d. Furthermore, PIN lesions were reported after neonatal exposure to 10 μg/kg · d with hormonal treatment in adulthood. No appropriately conducted studies contest this evidence. Therefore, the WoE analysis demonstrates that low doses of BPA significantly alter development of the rodent prostate. The NTP's review of the BPA literature in 2008 indicated that this agency agrees that there is now significant evidence that low-dose BPA adversely affects development of the prostate (273).

D. BPA and the mammary gland: undisputed evidence for low-dose effects

The mammary gland is a conspicuous choice to examine the effects of estrogenic compounds because this organ depends on estrogen for proper development at several critical periods in life (274). The fetal gland expresses ER in the mesenchymal compartment, and just before birth, the epithelium becomes ER positive as well (275). At puberty, estrogen is responsible for ductal elongation and overall development of the gland, allowing the epithelium to fill the stromal compartment in preparation for pregnancy and lactation. Although BPA is an example of a chemical that has been classified as a weak estrogen because it binds with a much lower affinity to ERα compared with 17β-estradiol, even weak estrogens are known to affect the development of the mammary gland during early development (276).

In the first study to examine the effects of BPA on the mammary gland, prepubertal rats were exposed to relatively high doses (100 μg/kg · d or 54 mg/kg · d) for 11 d. After even this short exposure, mammary gland architecture was affected in both dose groups, with increased numbers of epithelial structures and, in particular, structures that suggest advanced development (277). BPA exposure also altered proliferation rates of mammary epithelium and cell cycle kinetics, with an increased number of cells in S-phase and a decreased number of cells in G1. Although relatively high doses of BPA were examined, this initial study indicated that the prepubertal and pubertal gland could be sensitive to BPA.

Many additional studies have examined another critical period, the fetal and neonatal periods, which are sensitive to environmental estrogens (78, 276, 278). Mice exposed prenatally to low doses of BPA via maternal treatment (0.25 μg/kg · d) displayed altered development of both the stromal and epithelial compartments at embryonic d 18, suggesting that exposures affect tissue organization during the period of exposure (176). In addition, similar low doses produced alterations in tissue organization observed in puberty and throughout adulthood, long after exposures ended, and even induced pregnancy-like phenotypes in virgin females (137, 279–282). Female mice exposed to BPA *in utero* displayed heightened responses to estradiol at puberty, with altered morphology of their glands compared with animals exposed to vehicle *in utero* (138). Another study demonstrated that perinatal BPA exposure altered the mammary gland's response to progesterone (283). Remarkably, all of these effects were observed after maternal exposures to low doses (0.025–250 μg/kg), suggesting that the gland is extremely sensitive to xenoestrogen exposures. These studies are in contrast to one that examined the effects of higher doses (0.5 and 10 mg/kg · d) when BPA was administered for 4 d to the dam, which reported advanced development of BPA-exposed glands before puberty but no effects in adulthood (284).

Adult exposure to BPA is only now being examined in the mouse mammary gland model. A recent study examined the effects of BPA on mice with mutations in the *BRCA1* gene. This study reported that 4 wks of exposure to a low dose of BPA altered the tissue organization of the mammary gland in ways that are similar to the effects observed after perinatal exposure (285). This study focused on altered development of the gland during exposure; additional studies are needed to determine whether these effects are permanent or whether normal mammary morphology could be achieved by cessation of BPA exposure.

Another obvious endpoint is the effect of BPA exposure on mammary cancer incidence. Several studies indicate that exposure to BPA *in utero* produces preneoplastic (281, 286, 287) and neoplastic lesions (286) in the gland in the absence of any other treatment. Additionally, other studies show that females exposed to BPA during the perinatal period are more sensitive to mammary carcinogens, decreasing tumor latency and increasing tumor incidence (287–290). These studies are also supported by subsequent studies examining gene and protein expression, which show that low-dose BPA specifically up-regulates expression of genes related to immune function, cell proliferation, cytoskeletal function, and estrogen signaling and down-regulates apoptotic genes (282, 288, 289, 291).

Postnatal BPA exposures also influence mammary cancer incidence; animals exposed lactationally to BPA from postnatal d 2 until weaning displayed decreased tumor latency and increased tumor multiplicity after treatment with DMBA [7,12-dimethylbenz(a)anthracene], a carcinogen (292). This study suggested that BPA exposure led to increased cell proliferation and decreased apoptosis in the gland and shifted the period where the gland is most susceptible to mammary carcinogens, a result that has important implications for human breast cancer. Finally, an additional study examined the effects of adult BPA exposure on mammary cancer; this study demonstrated that low doses of BPA accelerate the appearance of mammary tumors in a tumor-prone mouse strain (293). Interestingly, high doses did not have this effect; thus, this study is also an excellent example of a NMDRC.

Two studies of BPA and the mammary gland seem to contradict this body of literature, but both examined extremely high doses. In the first study, Nikaido *et al.* (294) exposed female mice to 10 mg/kg BPA from postnatal d 15–18. Mammary glands from these animals were examined at 4, 8, and 24 wk of age, and no differences were observed in the exposed animals relative to controls. Although the lack of effects reported in this study could be due to the high dose employed, they could also be related to the relatively short exposure period during the preweaning phase. In the second study, Yin and colleagues (295) examined the effects of BPA during the first few days after birth (0.1 or 10 mg BPA, equivalent to approximately 10 and 1000 mg/kg) on the incidence of mammary tumors after exposure to a mammary carcinogen at puberty. Similar to the study described above, this one also examined the effects of BPA after a relatively short period of exposure (only three injections administered between postnatal d 2 and 6). Although the study showed that BPA affected tissue organization, there was no change in the incidence of tumors in BPA-exposed females. Because both of these studies examined both high doses and relatively short periods of exposure, it is difficult to compare them directly to the studies finding effects of BPA on the mammary gland after longer exposures to lower doses; at the very least, they cannot refute studies suggesting that BPA alters development of this gland.

In summary, the WoE clearly shows that low-dose BPA exposure affects development of the mammary gland, mammary histogenesis, gene and protein expression in the gland, and the development of mammary cancers. In fact, this example of low-dose effects produced remarkably similar effects across more than a dozen studies conducted in several different labs. These results are also consistent with the effects of low-dose BPA exposure on mammary epithelial cells in culture (reviewed in Ref. 30). Although epidemiology studies examining the influence of BPA on breast cancer rates have proven to be inconclusive at best (296), to replicate the animal studies discussed above, epidemiologists must collect information about prenatal and neonatal exposures and relate them to adult breast cancer incidence. These types of studies would take decades to conduct (67) and should take into consideration the effects of other estrogens, because their effects can be additive or even synergistic (143, 144, 297).

Although our analyses of BPA have focused on its effects on the mammary gland and prostate (see *Sections II.C–D*), it is worth noting that several other endpoints have strong data to support the hypothesis that BPA has low-dose effects. In a recent review using similar WoE approaches, Hunt and colleagues (298) focused on those studies that examined the effects of BPA on the oocyte, specifically scrutinizing studies that reported effects, or no effects, on meiotic aneuploidy and other alterations in the intracellular organization and chromosome abnormalities. Similar to what has been observed with the prostate and mammary gland, the effects observed in the oocyte are variable from study to study, but overall consistent, and suggest that BPA exposure produces defects in these cells.

A large number of studies have also focused on the effects of BPA on the brain and behavior, with the most significant effects on sexually dimorphic regions of the brain and behaviors (299–307). Other affected behaviors include social behaviors, learning and anxiety, and maternal-neonate interactions (reviewed in Refs. 29 and 308). The NTP expert panel statement concluded that there were significant trends in these behavioral data and wrote that there was some concern that BPA could have similar effects in humans (273). Low-dose effects have also been reported for BPA in the female reproductive tract (309, 310), immune system (311, 312), maintenance of body weight and metabolism (313, 314), fertility (315–317), and the male reproductive tract (259, 318) (see Refs. 29 and 319 for comprehensive reviews).

E. Another controversial low-dose example: atrazine and amphibian sexual development

Atrazine is an herbicide that is applied in large volumes to crops, and there is concern that agricultural runoff of this chemical can affect nontarget animal species, especially amphibians that live and reproduce in small ponds and streams where significant amounts of atrazine have been regularly measured (320–322). It is the most commonly detected pesticide in ground and drinking water. Atrazine induces aromatase expression in cells and animals after exposure (323); this ultimately causes an increase in the conversion of testosterone to estrogen (324, 325). This effect has been reported in all vertebrate classes examined: fish, amphibians, reptiles, birds, and mammals, including human cell lines (see Ref. 326 for review). Another well-documented effect of atrazine is that it decreases androgen synthesis and activity, again, in every vertebrate class examined (326). In addition, endocrine-disrupting effects of atrazine occur through a number of other mechanisms, including antiestrogenic activity (327), altered prolactin release (328), and increased glucocorticoid release from the adrenal glands (329, 330), among others (327).

Because of atrazine's indirect effect on estrogen levels, one relevant endpoint that has been given attention is the effect of this chemical on gonad differentiation in various amphibian species. The early gonad is bipotential, and in mammals, the expression of genes on the Y-chromosome is needed to masculinize the undifferentiated gonad; when this does not occur, the gonad develops into ovarian tissue. In *Xenopus laevis* frogs (and some other animals like birds), the opposite is true: females are heterogametic (*i.e.* ZW-chromosomes) and males have two of the same chromosomes (*i.e.* ZZ). In *X. laevis*, the W-chromosome is the dominant one, containing a gene, DM-W, which induces aromatase expression (331). Thus, having a W-chromosome is needed to produce estrogen; without the conversion of testosterone to estrogen, the frog develops as a male (332). Changes in sex ratio and gonadal morphology are therefore good indicators that an estrogen, or a chemical that up-regulates aromatase and indirectly increases estrogen levels, is present (76).

Determining a low-dose cutoff for atrazine is not a simple task. Although the safe limit of 3 μg/liter in drinking water was set by the EPA, actual levels in the environment often exceed this concentration (333), and levels in ponds and streams can reach 100 μg/liter (322) or more. In traditional toxicology studies examining several amphibian species, the LOAEL was set at 1.1 mg/liter, and the no observed effect level (NOEL) was 200 μg/liter (334, 335). Thus, using the definitions of low dose established by the NTP (2), we consider any treatment at or below 200 μg/liter to be a low dose.

In 2002, one of the first published studies to connect atrazine exposures to altered gonadal morphology examined *X. laevis* frogs exposed to 0.01–200 μg/liter throughout larval development (336). All doses from 0.1–200 μg/liter produced gonadal malformations including the presence of multiple gonads and hermaphroditism. Several other reports showed similar effects of low doses on gonadal phenotypes including studies that report the production of hermaphrodites and intersex frogs, males with ovotestes, and males with testicular oocytes (337–343). Additional studies showed that low-dose atrazine exposure (0.1–200 μg/liter in the water) during sexual differentiation caused testicular dysgenesis, testicular resorption, and testicular aplasia in male frogs (343, 344), and others indicated effects on sex ratios (339, 342, 345, 346). Importantly, these effects were not all observed at the same atrazine concentration, and the studies were conducted in several different species, with some reporting effects at low doses but no effects at higher doses (341) and others reporting effects in some but not all species (339). Examining these studies as a whole, there is clearly a pattern of effects that are reproducible from study to study, and they collectively support the hypothesis that atrazine disrupts sex hormone concentrations.

To date, five peer-reviewed studies have reported no effects of atrazine on sex ratios, gonadal morphology, the incidence of testicular abnormalities or testicular oocytes, gonad size, or the incidence of intersex phenotypes (347–351). Little can be ascertained from these negative studies, however, because four did not include any positive control, suggesting that the frogs used in those studies may have been incapable of responding to atrazine or any other hormonal treatment (347–350). Additionally, one of those studies reported testicular oocytes in the control frogs, suggesting either that the negative control population was contaminated with atrazine (or another EDC or hormone), or that an inappropriate strain of *X. laevis* was selected for the experiments (347). Only one study remains that did not find any effects of atrazine; this study used an appropriate positive control (17β-estradiol) and found effects of that hormone on sex ratios and the incidence of intersex gonads (351). An EPA expert panel noted, however, that this study used a strain of *X. laevis* that was obtained from a new, unexamined population of frogs from Chile and suggested that this strain may be insensitive to environmental chemicals. Furthermore, the panel called for additional analysis of the data in this study, including the statistical approaches; they suggested that an independent laboratory should evaluate the histopathological results; and they requested that atrazine metabolites be measured (352). The panel also proposed that these experiments should be repeated with an established *X. laevis* strain. Taking together the results of those studies that found effects of atrazine on sexual differentiation, and this one negative study, the WoE for the case of low-dose atrazine on sexual differentiation is clearly in support of adverse effects of this chemical.

Just as epidemiological studies have found links between EDCs and human diseases, ecological field studies have examined whether exposure to atrazine in natural environments affects the development of wild amphibians (343, 353–358). These studies have many of the same constraints as those observed in epidemiology: a paucity of data on early life exposures (including exposure levels of controls), limitations on the total number of EDCs that can be measured in environmental and biological samples, and a lack of causative relationships that can be established between exposures and effects. For these reasons, studies that found relationships between atrazine exposure (or concentrations in environmental samples) and effects on one or more aspect of sexual differentiation (343, 353–355) are considered weak, but significant, evidence for low-dose effects. The presence of several studies suggesting a relationship between low-dose exposure to atrazine in the wild and altered sexual differentiation indicates a plausible causal relationship. Because the ecological and laboratory data show similar effects of atrazine on gonadal development, this strengthens the conclusions of our WoE that low doses of atrazine cause harm to amphibians.

Feminization of males after atrazine exposure is not restricted to amphibians; exposure of zebrafish to low doses increased the ratio of female to male fish and increased expression of aromatase (359). Close to a dozen additional studies also report that environmentally relevant doses of atrazine can up-regulate aromatase, decrease testosterone, and/or increase estrogen levels in a large number of species (reviewed in Ref. 119), suggesting that low-dose effects of atrazine may be more widespread than their effects on the gonads of amphibians. Other studies indicate that low-dose atrazine affects the immune system and stress responses of salamanders (360–362), survivorship patterns of several frog species (363), and thyroid hormone and plasma ion concentrations in salmon (364).

An important factor to consider when examining the effects of atrazine on different animal models is the difficulty in identifying an appropriate low, environmentally relevant dose for all species. Aquatic animals can be housed in water containing levels of atrazine found in wild habitats, yet no toxicokinetic studies are available to determine what administered dose produces the levels of atrazine metabolites, typically in the parts-per-million or ppb range (365, 366), measured in human samples. There are also no blood or urine measurements in exposed rodents to compare with human levels; thus, extrapolations across species are estimates at best.

Keeping this qualification in mind, exposures in the range of 25–100 mg/kg · d during development have been shown to alter mammary gland development (367, 368), estrous cyclicity (369), serum and intratesticular testosterone concentrations (370), timing of puberty in males and prostate weight (371), and immune function (372) in rodents. Lower doses of atrazine metabolites (0.09–8.73 mg/kg · d) altered development of the mammary gland (373), male pubertal timing and prostate development (374). Identifying the range of doses administered to animals that produce the levels of atrazine and its metabolites measured in human blood and urine is an essential research need to pursue low-dose studies in rodents and other mammals.

F. Dioxin and spermatogenesis: low-dose effects from the most potent endocrine disruptor?

Dioxin, or TCDD, is formed as a byproduct of industrial processes as well as during waste incineration. Because TCDD is extremely toxic to some animals, with 1 μg/kg capable of killing 50% of guinea pigs, it has been labeled the most toxic chemical on earth (375). But interestingly, other animals are less sensitive to lethal effects of TCDD, with an LD_{50} of approximately 1000 μg/kg in hamsters, and studies also suggest that humans are not a hypersensitive species for lethality (376). Additionally, there are differences in the half-life of TCDD in different animals; in rodents, the half-life is 2–4 wks, but in humans, the half-life is approximately 10 yrs, and additional factors influence TCDD pharmacokinetics including the exposure level and the amount of body fat present (377–379). In cell cultures, doses as low as 10^{-11} M are toxic, with decreased viability observed even in cells maintained in nonproliferative states (380).

TCDD binds to the aryl hydrocarbon receptor (AhR), and differences in the affinity for the receptor may be responsible for differences in sensitivity between species (381). The K_d (dissociation constant for receptor-ligand binding kinetics) in human samples typically ranges from 3–15 nM, but in samples from rodents, the K_d is less than 1 nM (382). Importantly, there are also nongenomic pathways affected by TCDD that are mediated by AhR that are typically altered within minutes of TCDD exposure and therefore without changes in transcription (383). Yet many studies suggest that important differences exist between species regarding binding affinity of TCDD for AhR and the toxicity of this chemical, but that other adverse effects, including those related to the endocrine-disrupting activities of TCDD, occur at similar doses (or body burdens) across animal species (384, 385). Thus, it is plausible that AhR affinity alone can predict some, but not all, effects of TCDD and related chemicals.

The mechanisms responsible for many of the endocrine-disrupting activities of TCDD are currently not well understood. Knocking out AhR disrupts morphogenesis of several organ systems even in the absence of a ligand like TCDD, suggesting that this receptor plays important roles in early development (386). AhR is translocated to the nucleus after loss of cell-cell contacts and is often localized to the nucleus in embryonic cells, suggesting that it could have ligand-independent effects on development and/or that endogenous ligands could be present during early development (387). When TCDD is present, AhR translocates to the nucleus and dimerizes with ARNT, the aromatic hydrocarbon receptor nuclear translocator (388). Although the (currently unidentified) physiological activators of AhR are likely to induce rapid on/off signaling via AhR, TCDD and related compounds appear to maintain activation of AhR, and the presence of TCDD prevents the normal action of the AhR signaling pathway in the maintenance of homeostasis (389). This induces changes in the expression of genes and promotes the production of toxic metabolites. These effects may be responsible for some of the endocrine-related endpoints affected by TCDD exposure. Additionally, recent studies have shown complex and intricate interactions between the

AhR and ER signaling pathways (390), suggesting that dioxin may also have indirect effects on some ER-mediated endpoints via AhR signaling.

Teratogenic effects of TCDD have been well documented after high-dose (391, 392) and low-dose exposures (393). These studies show that almost every organ and system in the body is affected by this chemical. High doses that did not produce lethality caused severe weight loss, intestinal hemorrhaging, alopecia, chloracne, edemas, and severe liver damage. Sadly, there are now several examples in humans of accidental exposures after the industrial release of TCDD where a number of individuals have been exposed to large doses (389, 394) as well as a few documented intentional poisonings (395). The tolerated daily intake level was set at 1–4 pg/kg · d, although the doses consumed by nursing infants are likely to exceed these levels by a factor of 10 (375). Adult exposures usually result from the consumption of contaminated foods, and because TCDD is lipophilic, it is concentrated in the fat component of breast milk and therefore passed in large quantities from a nursing mother to her infant.

Using classical toxicology methods, the effects of single TCDD doses were examined in adult male rats, specifically focusing on the effects of this chemical on the number of spermatids per testis and the integrity of the testicular germinal epithelium (396). In one of the earliest studies, Chahoud and colleagues (397) determined a LOAEL of 3 μg/kg · d and set the NOAEL at 1 μg/kg · d for effects on the testes. Because there are significant differences in the toxicity of TCDD between animal models, and different endpoints have different identified NOAELs, we have selected the 1 μg/kg · d identified by Chahoud *et al.* as the cutoff for low-dose studies of this compound. This cutoff is based on the NTP's definition of low dose as occurring at doses lower than those tested in traditional toxicology assessments (2). However, it is important to acknowledge that body burdens that mimic those observed in human populations are likely the best indicators of low doses for TCDD (384), and thus we recommend that future studies determine body burdens after administration of TCDD for the specific strain, origin, and species of animal being tested to ensure that truly low doses, relevant to human populations, are being tested.

Several recent epidemiological studies have indicated that relatively high exposures to TCDD during early life (due to industrial release of high amounts of the chemical) can permanently affect semen quality and sperm count in men (398). Yet epidemiology studies also clearly show that the timing of TCDD exposure can vastly influence the effect of this chemical on spermatogenesis; exposures during perinatal life significantly reduced sperm parameters, but exposures during puberty increased sperm counts; exposures in adulthood had no effect on sperm parameters (399). Thus, it is also important for animal studies to focus on exposures during critical periods for development of the male reproductive tract and spermatogenesis in particular.

We are aware of 18 studies that have examined the effects of low doses ($\leq$1 μg/kg · d) of TCDD during perinatal development on male fertility endpoints in adulthood. The endpoints assessed vary, including epididymal sperm counts, ejaculated sperm number, daily sperm production, sperm transit rate, and percent abnormal sperm, and the sensitivity of these endpoints appears to impact the ability to detect low-dose effects in different studies (400, 401) (Table 5). In total, 16 rodent studies examined the effect of low-dose TCDD on epididymal sperm count; 12 showed significant effects on this endpoint (402–413), whereas the other four did not (414–417). Of the five studies that examined ejaculated sperm counts, four studies (404, 405, 408), including one examining rhesus monkeys (418), showed effects of low-dose TCDD, *i.e.* a significant decrease in sperm counts; one study found no effect (417). Daily sperm production was a less-sensitive endpoint, with four studies showing significant decreases after prenatal exposure to low doses (402, 403, 407, 409) and four studies showing no effects (406, 412, 413, 416); sperm transit rate was examined in only two studies, although both showed significant decreases in sperm tranfer rates (403, 410); and finally, three studies determined that low-dose TCDD produced abnormalities in sperm appearance or motility (414, 415, 419), but one study was not able to replicate these findings (417).

When examining the TCDD literature as a whole, the WoE strongly suggests that prenatal exposure to low doses of TCDD affects sperm-related endpoints in adulthood (Table 5). In all, only two studies were unable to detect any effect of TCDD on the sperm endpoints assessed, although both studies found effects of TCDD on other endpoints including the weight of the adult prostate (416) and the timing of puberty (417). No study on TCDD used a positive control, likely due to a paucity of information on the mechanisms of dioxin action, but this raises obvious questions about the ability of these experimental systems to detect effects on spermatogenesis. Finally, some of the inability to detect effects of TCDD could be due to the use of insensitive strains, because 1000-fold differences in sensitivity have been reported for different rodent strains (420).

Even though we have focused the majority of our attention on the effects of low-dose TCDD exposure on spermatogenesis, it should be noted that low doses of this chemical affect a multitude of endpoints in animals, altering immune function (421, 422), indicators of oxidative

TABLE 5. Summary of low-dose animal studies examining the effects of TCDD on spermatogenesis endpoints

Study	Administered dose (time of administration)	Animal	Epididymal sperm count	Ejaculated sperm no.	Daily sperm production	Sperm transit rate	% abnormal sperm
Mably *et al.* (409)	0.064–1 μg/kg (gestational d 15)	Rat	Decreased	NA	Decreased	NA	NA
Bjerke and Peterson (402)	1 μg/kg (gestational d 15)	Rat	Decreased	NA	Decreased	NA	NA
Gray *et al.* (404)	1 μg/kg (gestational d 8)	Rat	Not significant	Decreased	NA	NA	NA
	1 μg/kg (gestational d 15)	Rat	Decreased	Decreased	NA	NA	NA
	1 μg/kg (gestational d 11)	Hamster	Decreased	Decreased	NA	NA	NA
Sommer *et al.* (408)	1 μg/kg (gestational d 15)	Rat	Decreased	Decreased	Decreased	Not significant	Not significant
Wilker *et al.* (410)	0.5, 1 or 2 μg/kg (gestational d 15)	Rat	Decreased	NA	Unaffected	Increased	NA
Gray *et al.* (405)	0.05–1 μg/kg (gestational d 15)	Rat	Decreased	Decreased	Decreased	NA	NA
Faqi *et al.* (403)	0.025–0.3 μg/kg (before mating, then 0.005–0.06 μg/kg weekly [to dams])	Rat	Decreased	NA	Decreased	Increased	Increased
Loeffler and Peterson (412)	0.25 μg/kg (gestational d 15)	Rat	Decreased	NA	Unaffected	NA	NA
Ohsako *et al.* (416)	0.0125–0.8 μg/kg (gestational d 15)	Rat	Not significant	NA	Unaffected	NA	NA
Ohsako *et al.* (406)	1 μg/kg (gestational d 15)	Rat	Decreased	NA	Unaffected	NA	NA
	1 μg/kg/gestational d 18	Rat	Unaffected	NA	Unaffected	NA	NA
	1 μg/kg/postnatal d 2 (to pups)	Rat	Unaffected	NA	Unaffected	NA	NA
Simanainen *et al.* (407)	0.03–1 μg/kg (gestational d 15)	Rat	Decreased	NA	Decreased	NA	NA
Yonemoto *et al.* (417)	0.0125–0.8 μg/kg (gestational d 15)	Rat	Unaffected	Unaffected	NA	NA	Unaffected
Yamano *et al.* (714)	0.3 or 1 μg/kg (postnatal d 1 and then every week [to dams])	Rat	Not significant	NA	NA	NA	NA
Ikeda *et al.* (715)	0.4 μg/kg (before mating, then 0.08 μg/kg weekly [to dams])	Rat	Unaffected	NA	NA	NA	NA
Bell *et al.* (414)	0.05–1 μg/kg (gestational d 15)	Rat	Increased (at certain ages)	NA	NA	NA	Increased
Bell *et al.* (415)	0.0024–0.046 μg/kg (d 12 weeks before pregnancy through parturition)	Rat	Unaffected	NA	NA	NA	Increased
Arima *et al.* (418)	0.03 or 0.3 μg/kg (gestational d 20, then 5% of dose monthly [to dams])	Rhesus monkey	Decreased	Not significant	NA	NA	Not significant
Yamano *et al.* (419)	0.3 or 1 μg/kg (weekly to dams then pups [all postnatal])	Rat	NA	NA	NA	NA	Increased
Jin *et al.* (411)	1 μg/kg · d (postnatal days 1–4 [to dams])	Mouse	Decreased	NA	NA	NA	NA
Rebourcet *et al.* (413)	0.01–0.2 μg/kg (gestational d 15)	Rat	Decreased (at some ages)	NA	Not significant	NA	NA

Not significant indicates trend for effect but did not reach statistical significance. Unaffected means assessed, but no differences were observed relative to controls. Here, low doses were considered any at or below 1 μg/kg · d (see text for discussion of how this cutoff was established for rodent studies). NA, Not assessed.

stress (423–425), bone and tooth development (426, 427), female reproduction and timing of puberty (428–430), mammary gland development and suceptibility to cancers (431), behaviors (432, 433), and others. In several cases, lower doses were more effective at altering these endpoints than higher ones (423, 424, 426, 433). Epidemiology studies of nonoccupationally exposed individuals also indicate that serum TCDD levels may be linked to diseases in humans as well (434). Mean serum TCDD levels have decreased by a factor of 7 over a 25-yr period (1972–97) in several industrial nations (435), but results from both animal and epidemiological studies suggest that even the low levels detected now could have adverse effects on health-related endpoints.

G. Perchlorate and thyroid: low-dose effects in humans?

A significant challenge with observing low-dose effects of EDCs in the human population is that human chemical exposures are multivariate along the vectors of time, space, and sensitivities. In addition, chemicals can exert effects on several systems simultaneously. Therefore, associations in human studies between exposures and disease are difficult to reconcile with experimental studies in animal model systems. For this reason, the literature describing the potential impacts of perchlorate contamination on the human population is potentially clarifying because to the best of our knowledge, perchlorate exerts only a single effect, and the pharmacology of perchlorate exposures has been studied in human volunteers (436). This literature offers a unique perspective into the issue of low-dose effects, perhaps providing important hypotheses to explain mechanistically why high-dose, short-term experiments can fail to predict the outcome of low-dose, lifetime exposures.

In the 2001–2002 NHANES dataset, perchlorate was detected in the urine of each of the 2820 samples tested (437). This widespread exposure means that the human population is being continuously exposed because perchlorate has a half-life in the human body of about 8 h (438). Human exposures to perchlorate are likely attributed to both contaminated drinking water and food (439); in fact, a recent analysis concludes that the majority of human exposure to perchlorate comes from food (440).

The predominant theory proposed to explain the source of perchlorate contamination in the United States is that it has been employed for many decades as the principal oxidant in explosives and solid rocket fuels (441). Perchlorate is chemically stable when wet and persists for long periods in geological systems and in ground water. Because of disposal practices during the 1960s through 1990s, perchlorate became a common contaminant of ground water in the United States (441, 442). Perchlorate is also formed under certain kinds of natural conditions (443), although the relative contributions to human exposure of these different sources is not completely understood. As a result of perchlorate contamination of natural waters, the food supply has become contaminated through irrigation in part because both aquatic and terrestrial plants can concentrate perchlorate more than 100-fold over water levels (444).

This exposure profile in the human population is important because high doses of perchlorate are known to reduce functioning of the thyroid gland, and poor thyroid function is an important cause of developmental deficits and adult disease (445). The primary question is: at what dose does perchlorate inhibit thyroid function sufficiently to cause disease? The current literature, reviewed below, supports the view that background exposure may affect thyroid function in adult women. These exposure levels, however, are considerably lower than predicted by early toxicology experiments in humans.

Perchlorate reduces thyroid function by inhibiting iodide uptake by the sodium/iodide symporter (NIS) (446), which is the only known effect of perchlorate on human physiology (438). NIS is responsible for transporting iodide into the thyroid gland, which is required for the production of thyroid hormone (447). However, NIS is also expressed in the gut (448, 449), in lactating breast (448, 450, 451), and in placenta (452), presumably all as a delivery mechanism for iodide to the developing and adult thyroid gland. Because the NIS transports perchlorate (450), the pathway by which humans take up and concentrate perchlorate is the same as the pathway by which humans take up and concentrate iodide. Interestingly, NIS expression in the human fetal thyroid gland is the rate-limiting step in production of thyroid hormone (453). Moreover, NIS transport of perchlorate explains why high levels of perchlorate are found in human amniotic fluid (454, 455) and breast milk (456–459).

This effect of perchlorate on thyroid function is important because thyroid hormone is essential for normal brain development, body growth as well as for adult physiology (445, 460). Moreover, it has become clear that even small deficits in circulating thyroid hormone in pregnant women (461, 462) or neonates (463) have permanent adverse outcomes. In fact, recent work indicates that very subtle thyroid hormone insufficiency in pregnant women is associated with cognitive deficits in their children (461). Because of the importance of thyroid hormone in development and adult physiology, and because perchlorate is a potent inhibitor of iodide uptake and thyroid hormone synthesis, identifying the dose at which these events occur is critical.

Perchlorate was used medically to reduce circulating levels of thyroid hormone in patients with an overactive thyroid gland in the 1950s and 1960s (reviewed in Ref. 446); therefore, it was reasonable to examine the dose-response characteristics of perchlorate on the human thyroid gland. Because perchlorate inhibits iodide uptake, several studies were performed to evaluate the effect of perchlorate exposure on iodide uptake inhibition in human volunteers (438, 464–466). In one study, 0.5 or 3 mg/d (approximately 0.007 and 0.04 mg/kg · d) perchlorate was administered to healthy volunteers ($n = 9$ females and 5 males, age 25–65 yr), and no effects were observed (466). Of course, it is important to note that the 2 wk of administration tested in this study is not sufficient to see any effect on serum concentrations of T_4 or TSH; the healthy thyroid can store several months' worth of thyroid hormone in the gland (467). Another small study also found no effects of administering 3 mg/d (approximately 0.04 mg/kg · d) on any thyroid endpoint assessed ($n = 8$ adult males) (464).

In contrast, two studies examining adult volunteers administered perchlorate found effects of this chemical on at least one endpoint. The first found that radioactive iodide uptake was affected by 2 wk of exposure to 10 mg/d (0.13 mg/kg · d), but other measures of thyroid function were not altered ($n = 10$ males) (465). The second examined adults ($n = 37$) given doses ranging from 0.007–0.5 mg/kg · d; all but the lowest dose altered radioactive iodide uptake, and only the highest dose altered TSH levels (438). These studies were interpreted to suggest that adults would have to consume 2 liters of drinking water daily that was contaminated with at least 200 ppb (200 μg/liter) perchlorate to reach a level in which iodide uptake would begin to be inhibited. Yet, these administered doses are high and relatively acute, so the derivation of a safe dose from these studies, applied to vulnerable populations such as those with low iodide intake, has been strongly disputed (471).

Studies of occupational exposures have also been used to examine the effects of exposure to relatively high levels of perchlorate. In the first such study, more than 130 employees were separated into eight groups based on exposure estimates from airborne perchlorate in the workplace (472). The authors found that individuals with longer daily exposures to perchlorate, due to longer work shifts, had significant decreases in TSH levels compared with individuals with shorter exposures. But this study was hampered because actual exposure levels were not measured via urine or blood samples. A second study examined 37 employees exposed to perchlorate and 21 control employees from an azide factory; actual exposure measures were not conducted, but estimates were calculated based on exposures to perchlorate dust and air samples (473). This study found no effects of perchlorate exposures on any thyroid endpoint, although the sample size examined was small. In the final occupational exposure study, serum perchlorate levels were measured and compared with several measures of thyroid function in workers (n = 29) who had spent several years as employees in a perchlorate production plant (474). In this study, the most complete because of the biomonitoring aspect of the exposure measures, higher perchlorate levels were associated with lower radioactive iodide uptake, higher urinary iodide excretion, and higher thyroid hormone concentrations.

Although iodide uptake was often inhibited in these studies, serum thyroid hormones were typically not altered, perhaps because of sufficient stored hormone. Based on these observations, the National Academy Committee to Assess the Health Implications of Perchlorate Ingestion (467) estimated that perchlorate would have to inhibit thyroid iodide uptake by about 75% for several months to cause a reduction in serum thyroid hormones. Moreover, the drinking water concentration of perchlorate required for this kind of inhibition was estimated to be over 1,000 ppb (438). Therefore, the National Academy of Sciences committee recommended a reference dose of 0.0007 mg/kg · d (467), based on the dose at which perchlorate could inhibit iodide uptake, and the EPA used this value to set a provisional drinking water standard of 15 ppb.

Considering these data and general knowledge about the thyroid system, it was unexpected that Blount *et al.* (475) would identify a positive association between urinary iodide and serum TSH in adult women in the NHANES 2001–2002 dataset. Yet several features of this dataset were consistent with a causal action of perchlorate on thyroid function. First, in the general population of adult women, urinary perchlorate was positively associated with serum TSH. In the population of adult women who also had low urinary iodide, however, urinary perchlorate was more strongly associated with serum TSH and was negatively associated with serum T_4. The strength of this association was such that the authors calculated that women at the 50th percentile of perchlorate exposure experienced a 1 μg/dl T_4 reduction (reference range = 5–12 μg/dl). Should this magnitude of reduction in serum T_4 occur in a neonate, measurable cognitive deficits would also be present (476). Finally, Steinmaus *et al.* (477), using the same NHANES dataset, showed that women with low urinary iodide who smoke had an even stronger association between urinary perchlorate and measures of thyroid function. Tobacco smoke delivers thiocyanates, which also inhibit NIS-mediated iodide uptake (446).

The NHANES dataset suggests that perchlorate exposures of 0.2–0.4 μg/kg · d (440) are associated with depressed thyroid function, even when urinary iodide is not reduced. This is a considerably lower dose than the 7 μg/kg · d dose required to suppress iodide uptake in the Greer *et al.* (438) study or the 500 μg/kg · d the NAS estimated would be required for several months to actually cause a decline in serum T_4. Therefore, it is reasonable to question whether these associations represent a causative relationship between perchlorate and thyroid function.

A number of epidemiological studies have been published to test for a relationship between perchlorate exposure and thyroid function. Early work used neonatal screening data for T_4 as a measure of thyroid function, and the city of birth (Las Vegas, NV, compared with Reno, NV) as a proxy measure of exposure (478, 479). The reported findings were negative, but we now know that all Americans are exposed to perchlorate, so there was considerable misclassification of exposure, and no relationship should have been observed. Several additional studies using similar flawed designs also found no relationship between proxy measures of perchlorate exposures and clinical outcomes (480–484).

A recent study of the neonatal screening data from 1998 in California identified a strong association between neonatal TSH and whether or not the mother resided in a contaminated area (485). This study included over 497,000 TSH measurements and 800 perchlorate measurements. In addition, they used as a cutoff a variety of TSH levels (as opposed to the 99.9th percentile used for the diagnosis of congenital hypothyroidism), indicating that perchlorate exposure is not associated with congenital hypothyroidism. Two additional studies have shown similar relationships between perchlorate and TSH levels, particularly in families with a history of thyroid disease (486, 487).

Several studies in pregnant women have failed to identify a relationship between perchlorate exposure and measures of thyroid function (488–490). Although these are important studies that need to be carefully scrutinized, they do not replicate or refute the NHANES dataset. It thus remains important to conduct additional studies exploring the relationship between background exposure to perchlorate and thyroid function in adults, pregnant women, neonates, and infants. This effort will be challenging because of the different characteristics of thyroid function and hormone action at different life stages (460). In addition, it will be important to obtain individual measurements of exposures to perchlorate and other NIS inhibitors (thiocyanate and nitrate), and iodide itself as well as individual measures of thyroid function (free and total T_4 and TSH).

If background levels of perchlorate affect thyroid function in any segment of the population, it will be challenging to explain how the high-dose, short-term experiments of Greer *et al.* (438) completely underestimated the sensitivity of the human thyroid gland to perchlorate exposure. One possibility is that physiological systems respond to short durations of robust stress with compensatory mechanisms that reset during periods of long-term stress.

When these data are examined together, several important issues are raised. First, this example illustrates the difficulties inherent in studying human populations; epidemiology yields associations, not cause-effect relationships, in many cases using surrogate markers for perchlorate, and is not able to distinguish short- *vs.* long-term exposure duration. Second, our WoE analysis suggests that there is weak evidence for low-dose effects of perchlorate; further research is needed. The relationship between low-dose perchlorate exposures and thyroid endpoints would be strengthened by the addition of studies that measure biological concentrations of perchlorate and compare them with thyroid endpoints in neonates and other vulnerable populations. Third, the published studies that reported low-dose effects of perchlorate typically examined very specific populations, with several focusing on women with low iodine intake. This observation suggests that some groups may be more vulnerable to low doses of perchlorate than others (491).

H. Low-dose summary

These examples, and the examples of low-dose effects in less well-studied chemicals (Table 3), provide evidence that low-dose effects are common in EDC research and may be the default expectation for all chemicals with endocrine activity. Many known EDCs have not been examined for low-dose effects, but we predict that these chemicals will have effects at low doses if studied appropriately. Although studies unable to detect effects at low doses have received attention, including some studies designed to replicate others that reported low-dose effects, the majority of these studies contain at least one major design flaw. Thus, a WoE approach clearly indicates that low-dose effects are present across a wide span of chemical classes and activities.

III. Nonmonotonicity in EDC Studies

A concept related to low dose is that of nonmonotonicity. As noted in *Section I.B*, in a monotonic response, the observed effects may be linear or nonlinear, but the slope does not change sign (Fig. 3, A and B). In contrast, a dose-response curve is nonmonotonic when the slope of the curve changes sign somewhere within the range of doses examined (Fig. 3C). NMDRCs are often U-shaped (with maximal responses of the measured endpoint observed at low and high doses) or inverted U-shaped (with maximal responses observed at intermediate doses) (Fig. 3C, *top panels*). Some cases are more complicated, with multiple points along the curve at which the slope of the curve reverses sign (Fig. 3C, *bottom left*). Nonmonotonicity is not synomymous with low dose, because there are low-dose effects that follow monotonic dose-response curves. Thus, it is not required that a study include doses that span from the true low-dose range to the high toxicological range to detect nonmonotonicity. The consequence of NMDRCs for toxicity testing is that a safe dose determined from high doses does not guarantee safety at lower, untested doses that may be closer to current human exposures.

Examples of NMDRCs from the cell culture, animal, and epidemiological literature will be discussed in detail in *Section III.C*. Importantly, our review of the literature finds that NMDRCs are common in the endocrine and EDC literature. In fact, it is plausible that, considering the mechanisms discussed below, NMDRCs are not the exception but should be expected and perhaps even common.

A. Why is nonmonotonicity important?

NMDRCs in toxicology and in the regulatory process for EDCs are considered controversial. In addition to discussions of whether NMDRCs exist, there is also discussion of whether those that do exist have relevance to

Figure 3.

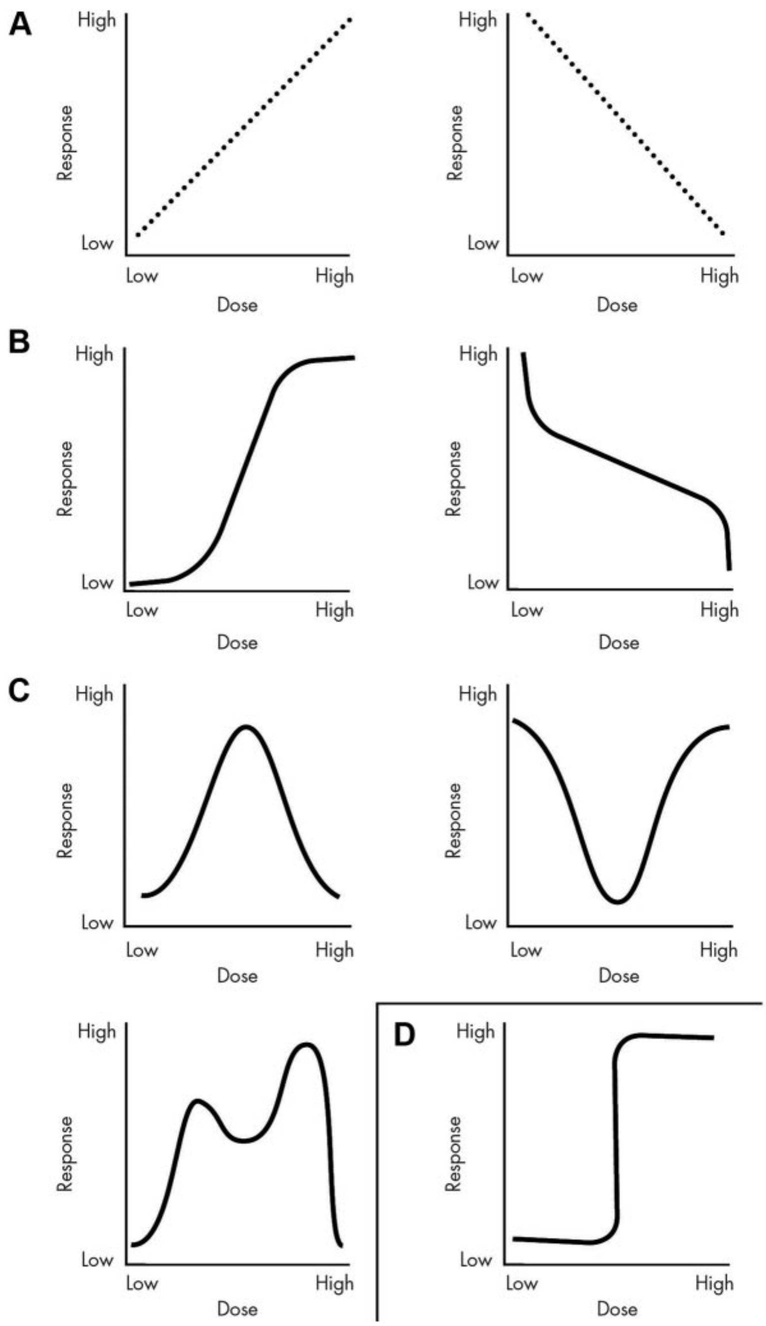

Figure 3. Examples of dose-response curves. A, Linear responses, whether there are positive or inverse associations between dose and effect, allow for extrapolations from one dose to another. Therefore, knowing the effects of a high dose permits accurate predictions of the effects at low doses. B, Examples of monotonic, nonlinear responses. In these examples, the slope of the curve never changes sign, but it does change in value. Thus, knowing what happens at very high or very low doses is not helpful to predict the effect of exposures at moderate doses. These types of responses often have a linear component within them, and predictions can be made within the linear range, as with other linear responses. C, Displayed are three different types of NMDRCs including an inverted U-shaped curve, a U-shaped curve, and a multiphasic curve. All of these are considered NMDRCs because the slope of the curve changes sign one or more times. It is clear from these curves that knowing the effect of a dose, or multiple doses, does not allow for assumptions to be made about the effects of other doses. D, A binary response is shown, where one range of doses has no effect, and then a threshold is met, and all higher doses have the same effect.

toxicological determination of putative safe exposures. In the standard practice of regulatory toxicology, the calculated safe dose, also called a reference dose, is rarely tested. In a system that is responding nonmonotonically, it is not appropriate to use a high-dose test to predict low-dose effects. Unfortunately, all regulatory testing for the effects of chemical exposures assume that this is possible. All current exposure standards employed by government agencies around the world, including the FDA and EPA, have been developed using an assumption of monotonicity (492, 493). The low-dose range, which presumably is what the general public normally experiences, is rarely, if ever, tested directly.

The standard procedure for regulatory testing typically involves a series of tests to establish the lowest dose at which an effect is observable (the LOAEL), then a dose beneath that at which no effect is observable (the NOAEL). Then a series of calculations are used to acknowledge uncertainty in the data, species differences, age differences, *etc.*, and those calculations, beginning with the LOAEL or the NOAEL, produce a reference dose that is presumed to be a safe exposure for humans (Fig. 4). Typically, the reference dose is 3- to 1000-fold lower than the NOAEL. That reference dose then becomes the allowable exposure and is deemed safe, even when it is never examined directly. For chemicals with monotonic linear dose-response curves (Fig. 3A), this may be appropriate. But for any chemicals that display nonmonotonic patterns, it is likely to lead to false negatives, *i.e.* concluding that exposure to the reference dose is safe when in fact it is not.

As described above, there are other nonlinear dose-response curves that are monotonic (Fig. 3B). These curves may also present problems for extrapolating from high doses to low doses because there is no linear relationship that can be used to predict the effects of low doses. Equally troubling for regulatory purposes are responses that have a binary response rather than a classical dose-response curve (Fig. 3D). In these types of responses, one range of doses has no effect on an endpoint, and then a threshold is met, and all higher doses have the same effect. An example is seen in the atrazine literature, where doses below 1 ppb had no effect on the size of the male larynx but doses at or above 1 ppb produced a significant decrease in size of approximately 10–15% (336). Even doses of 200 ppb, the toxicological NOEL, produce the same effect. Thus, this all-or-none effect is observed because atrazine does not shrink the larynx; instead, it removes the stimulatory agent (*i.e.* androgens). In the absence of some threshold dose of androgen, the larynx simply remains at the unstimulated (female) size. The EPA's assessment of this study and others was that the lack of a dose-dependent response negates the importance of this effect (352). The lack of a dose response for a threshold effect like larynx size does not mean that the effects are not dose dependent; thus, understanding these types of effects and their implications for risk assessments is essential for determining the safe levels of chemicals.

It is important to mention here that the appropriateness of determining NOAEL concentrations, and therefore calculating reference doses, from exposures to endogenous hormones or EDCs has been challenged by several studies (Fig. 4A) (494–496). These studies show that hormonally active agents may still induce significant biological effects even at extremely low concentrations and that presently available analytical methods or technologies might be unable to detect relatively small magnitudes of effects. Previous discussions of this topic have shown that as the dose gets lower (and approaches zero) and the effect size decreases, the number of animals needed to achieve the power to detect a significant effect would have to increase substantially (497). Even more importantly, the assumption of a threshold does not take into account situations where an endogenous hormone is already above the dose that causes detectable effects and that an exogenous chemical (whether an agonist or antagonist) will modulate the effect of the endogenous hormone at any dose above zero (Fig. 4B). There can thus be no threshold or safe dose for an exogenous chemical in this situation. Forced identification of NOAEL or threshold doses based on the assumption that dose-response curves are always monotonic without considering the background activity of endogenous hormones and the limitations of analytical techniques supports the misconception that hormonally active agents do not have any significant biological effects at low doses. Thus, the concept that a toxic agent has a safe dose that can be readily estimated from the NOAEL derived from testing high, acutely toxic doses is overly simplistic and contradicted by data when applied to EDC (5, 497, 498).

B. Mechanisms for NMDRCs

Previously, the lack of mechanisms to explain the appearance of NMDRCs was used as a rationale for ignoring these phenomena (492, 493). This is no longer acceptable because there are several mechanisms that have been identified and studied that demonstrate how hormones and EDCs produce nonmonotonic responses in cells, tissues, and animals. These mechanisms include cytotoxicity, cell- and tissue-specific receptors and cofactors, receptor selectivity, receptor down-regulation and desensitization, receptor competition, and endocrine negative FEEDBACK loops. These mechanisms are well understood, and by providing detailed biological insights at the molecular level into the etiology of NMDRCs, they strongly negate the presumption that has been central to regulatory toxicology that dose-response curves are by default monotonic.

1.Cytotoxicity

The simplest mechanism for NMDRCs derives from the observation that hormones can be acutely toxic at high doses yet alter biological endpoints at low, physiologically relevant doses. Experiments working at concentrations that are cytotoxic are incapable of detecting responses that are mediated by ligand-binding interactions. For example, the MCF7 breast cancer cell line proliferates in response to estradiol in the low-dose range (10^{-12} to 10^{-11} M) and in the pharmacological and toxicological range (10^{-11} to 10^{-6} M), but toxic responses are observed at higher doses (38). Thus, when total cell number is graphed, it displays an inverted U-shaped response to estrogen. But cells that do not contain ER, and therefore cannot be affected by the hormonal action of estradiol, also display cytotoxic responses when treated with high doses of hormone. These results clearly indicate that the effects of estradiol at high doses are toxic via non-ER-mediated mechanisms.

2. Cell- and tissue-specific receptors and cofactors

Some NMDRCs are generated by the combination of two or more monotonic responses that overlap, affecting a common endpoint in opposite ways via different pathways. For example, *in vitro* cultured prostate cell lines demonstrate a nonmonotonic response to increasing doses of androgen where low doses increase cell number and higher doses decrease cell number, thus producing an inverted U-shaped curve (499, 500). Although the parental cell expressed an inverted U-shaped dose-response curve, after a long period of inhibition, the effects on cell number could be segregated by selecting two populations of cells: one that proliferated in the absence of androgens and other cells that proliferated in the presence of high androgen levels (501). Thus, the observed inverted U-shaped response is due to actions via two independent pathways that can be separated from each other in an experimental setting (502). Similarly, estrogens have been shown to induce cell proliferation and inhibit apoptosis in several cell populations, but inhibit proliferation and induce apopto-

Figure 4.

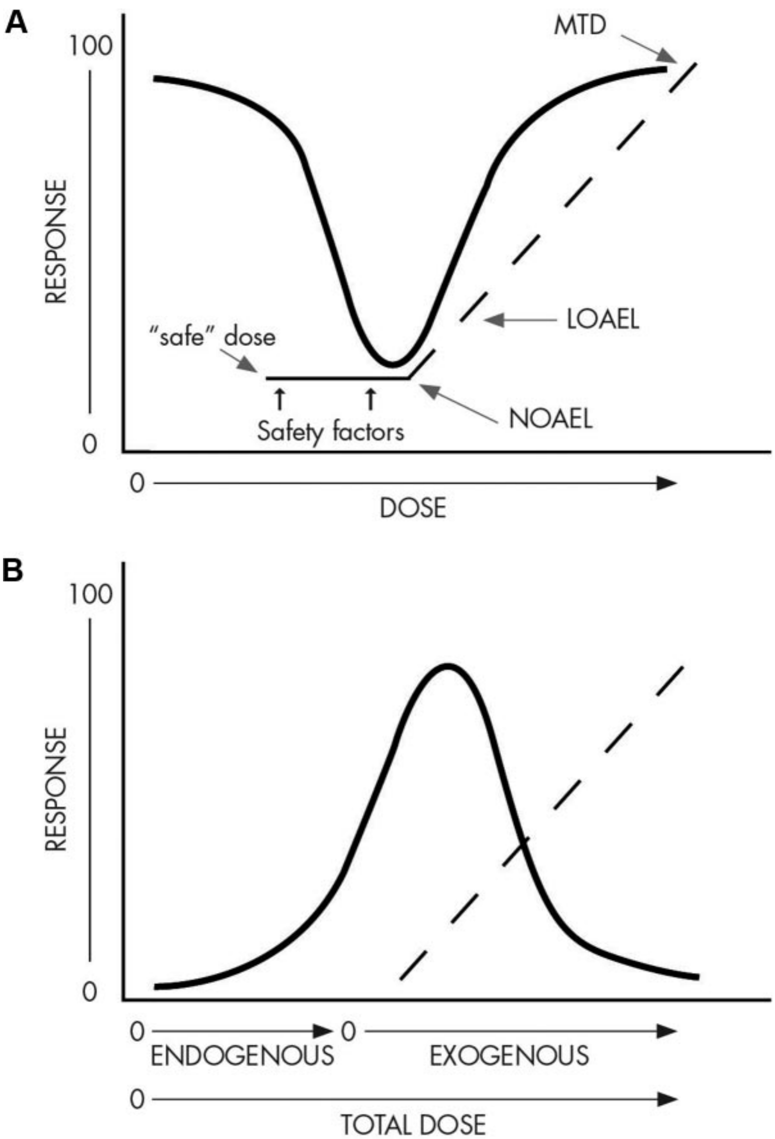

Figure 4. NOAEL, LOAEL, and calculation of a safe reference dose. A, In traditional toxicology testing, high doses are tested to obtain the maximum tolerated dose (MTD), the LOAEL, and the NOAEL. Several safety factors are then applied to derive the reference dose, *i.e.* the dose at which exposures are presumed safe. This reference dose is rarely tested directly. Yet when chemicals or hormones produce NMDRCs, adverse effects may be observed at or below the reference dose. Here, the doses that would be tested are shown by a *dotted line*, and the calculated safe dose is indicated by a *thick solid line*. The actual response, an inverted U-shaped NMDRC, is shown by a *thin solid line*. B, Experimental data indicate that EDCs and hormones do not have NOAELs or threshold doses, and therefore no dose can ever be considered safe. This is because an exogenous hormone (or EDC) could have a linear response in the tested range (*dotted line*), but because endogenous hormones are present (*thin solid line*), the effects of the exogenous hormone are always observed in the context of a hormone-containing system.

sis in others (503, 504), with the combined effect being an inverted U-shaped curve for cell number (505).

Why does one single cell type have different responses to different doses of the same hormone? The case of the prostate cell line described above is reminiscent of the results described from the transcriptome of MCF7 cells, whereby a discrete global response like cell proliferation manifests at significantly lower estrogen doses than the induction of a single marker gene (135). That a response like cell proliferation requires a significantly lower dose of hormone than the dose needed to induce a given target gene is counterintuitive but factual; it may be interpreted as consistent with the notion that metazoan cells, like cells in unicellular organisms, are intrinsically poised to divide (503, 506, 507) and that quiescence is an induced state (508, 509). The biochemical details underlying these different responses are largely unknown; however, recent studies showed that steroid receptors control only a portion of their target genes directly via promoter binding. The majority of the changes are indirect, through chromatin rearrangements (510, 511).

Why do different cell types (*in vitro* and *in vivo*) have different responses to the same hormone? One answer is that they may express different receptors, and these receptors have different responses to the same hormone. For example, some tissues express only one of the two major ER (ERα and ERβ), and actions via these receptors are important not just for responsiveness to hormone but also for cellular differentiation and cross talk between tissue compartments (512). Yet other tissues express both ERα and ERβ, and the effects of signaling via these two receptors often oppose each other; *i.e.* estrogen action via ERα induces proliferation in the uterus, but ERβ induces apoptosis (154). Complicating the situation further, different responses to a hormone can also be obtained due to the presence of different cofactors in different cell and tissue types (513, 514); these coregulators influence which genes are transcriptionally activated or repressed in response to the presence of hormone. They can also influence ligand selectivity of the receptor and DNA-binding capacity, having tremendous impact on the ability of a hormone to have effects in different cell types (105, 515, 516).

Although much of these activities occur on a biochemical level, *i.e.* at the receptor, there is also evidence that nonmonotonicity can originate at the level of tissue organization. The mammary gland has been used as a model to study inter- and intracompartmental effects of hormone treatment: within the ductal epithelium, estrogen has distinct effects during puberty, both inducing proliferation, which causes growth of the ductal tree, and inducing apoptosis, which is required for lumen formation (517, 518); in cell culture, the presence of stromal cells can also enhance the effects of estrogen on epithelial cells (519, 520), suggesting that stromal-epithelial compartmental interactions can mediate the effects of estrogen.

3. Receptor selectivity

NMDRCs can occur because of differences in receptor affinity, and thus the selectivity of the response, at low *vs.* high doses. For example, at low doses, BPA almost exclusively binds to the ER (including mER), but at high doses it can also bind weakly to other hormone receptors, like androgen receptor and thyroid hormone receptor (249, 521). This type of receptor nonselectivity is quite common for EDCs, and it has been proposed that binding to different receptors may be an explanation for the diverse patterns of disease observed after EDC exposures (522). In fact, several of the chemicals shown to have low-dose effects are known to act via multiple receptors and pathways (Table 3). Thus, the effects seen at high doses can be due to action via the binding of multiple receptors, compared with the effects of low doses, which may be caused by action via only a single receptor or receptor family.

4. Receptor down-regulation and desensitization

When hormones bind to nuclear receptors, the ultimate outcome is a change in the transcription of target genes. When the receptor is bound by ligand, an increase in response is observed; as discussed previously in this review, the relationship between hormone concentration and the number of bound receptors, as well as the relationship between the number of bound receptors and the biological effect, is nonlinear (38). After the nuclear receptor is bound by hormone and transcription of target genes has occurred (either due to binding of the receptor at a DNA response element or the relief of a repressive event on the DNA), the reaction eventually must cease; *i.e.* the bound receptor must eventually be inactivated in some way. Thus, nuclear hormone receptors are ubiquitinated and degraded, usually via the proteasome (523). Importantly, the role of the hormone in receptor degradation differs depending on the hormone; binding of estrogen, progesterone, and glucocorticoid mediates the degradation of their receptors (524–526), whereas the presence of hormone may actually stabilize some receptors and prevent degradation (527), and other receptors are degraded without ligand (528). As hormone levels rise, the number of receptors being inactivated and degraded also rises, and eventually the number of receptors being produced cannot maintain the pace of this degradation pathway (523). Furthermore, the internalization and degradation of receptors can also influence receptor production, leading to an even stronger down-regulation of receptor (529). In the animal, the role of receptor down-regulation is actually quite complex, because signaling from one hormone receptor can influence protein levels of another receptor; *i.e.* ER signaling can promote degradation of the glucocorticoid receptor by increasing the expression of enzymes in the proteasome pathway that degrade it (530).

There is also the issue of receptor desensitization, a process whereby a decrease in response to a hormone is not due to a decrease in the number of available receptors but instead due to the biochemical inactivation of a receptor (531). Desensitization typically occurs when repeated or continuous exposure to ligand occurs. Normally seen with membrane-bound G protein-coupled receptors, the activation of a receptor due to ligand binding is quickly followed by the uncoupling of the activated receptor from its G proteins due to phosphorylation of these binding partners (532). Receptor desensitization has been observed for a range of hormones including glucagon, FSH, human chorionic gonadotropin, and prostaglandins (533). Importantly, desensitization and down-regulation can occur in the same cells for the same receptor (534), and therefore, both can play a role in the production of NMDRCs.

5. Receptor competition

Mathematical modeling studies suggest that the mixture of endogenous hormones and EDCs establishes a natural environment to foster NMDRCs. Using mathematical models, Kohn and Melnick (42) proposed that when EDC exposures occur in the presence of endogenous hormone and unoccupied hormone receptors, some unoccupied receptors become bound with the EDC, leading to an increase in biological response (*i.e.* increased expression of a responsive gene, increased weight of an organ, *etc.*). At low concentrations, both the endogenous hormone and the EDC bind to receptors and activate this response, but at high doses, the EDC can outcompete the natural ligand. The model predicts that inverted U-shaped curves would occur regardless of the binding affinity of the EDC for the receptor and would be abolished only if the concentration of natural hormone were raised such that all receptors were bound.

6. Endocrine negative FEEDBACK loops

In several cases, the control of hormone synthesis is regulated by a series of positive- and negative feedback loops. Several hormones are known to control or influence their own secretion using these feedback systems. In one example, levels of insulin are known to regulate glucose uptake by cells. Blood glucose levels stimulate insulin production, and as insulin removes glucose from circulation, insulin levels decline. Thus, NMDRCs can occur as the free/available ligand and receptor concentrations are influenced by one another. In another example, thyroid hormone secretion is stimulated by TSH, and thyroid hormone suppresses TSH; thus, feedback between these two hormones allows thyroid hormone to be maintained in a narrow dose range.

Several studies indicate that these negative feedback loops could produce NMDRCs when the duration of hormone administration is changed (535). For example, short exposures of estrogen induce proliferation in the uterus and pituitary, but longer hormone regimens inhibit cell proliferation (236, 536). Thus, the outcome is one where exposure to a single hormone concentration stimulates an endpoint until negative feedback loops are induced and stimulation ends (537).

7. Other downstream mechanisms

Removing the variability that can come from examining different cell types, or even single cell types in the context of a tissue, studies of cultured cells indicate that different gene profiles are affected by low doses of hormone compared with higher doses. In a study of the genes affected by low *vs.* higher doses of estrogen, researchers found that there were a small number of genes in MCF7 breast cancer cells with very high sensitivity to low doses of estradiol (10 pM) compared with the total number of genes that were affected by higher (30 or 100 pM) exposures (538). But the surprising finding was the pattern of estradiol-induced *vs.* estradiol-suppressed gene expression at high and low doses; when 10 pM was administered, the number of estradiol-suppressible genes was approximately three times higher than the number of estradiol-inducible genes. However, the overall profile of the number of estradiol-suppressible genes was approximately half the total number of estradiol-inducible genes. This observation suggests that low doses of estrogen selectively target a small subset of the total number of estrogen-sensitive genes and that the genes affected by low doses are most likely to be suppressed by that treatment. The mechanisms describing how low doses of estrogen differently affect the expression of genes compared with higher doses have yet to be elucidated, but low doses of estradiol inhibit expression of apoptotic genes (539), indicating that which genes are affected by hormone exposure is relevant to understand how low doses influence cellular activities.

C. Examples of nonmonotonicity

1. Examples of NMDRCs from cell culture

A tremendous amount of theoretical and mathematical modeling has been conducted to understand the production of nonlinear and nonmonotonic responses (42, 540). These studies and others suggest that the total number of theoretical response curves is infinite. Yet this does not mean that the occurrence of NMDRCs is speculative; these types of responses are reported for a wide variety of chemicals. Cell culture experiments alone provide hundreds of examples of nonmonotonic responses (see Table 6 for examples). In the natural hormone category, many different hormones produce NMDRCs; this is clearly not a phenomenon that is solely attributable to estrogen and androgen, the hormones that have been afforded the most attention in the dose-response literature. Instead, NMDRCs are observed after cells are treated with a range of hormones, suggesting that this is a fundamental and general feature of hormones.

Chemicals from a large number of categories with variable effects on the endocrine system also produce NMDRCs in cultured cells. These chemicals range from components of plastics to pesticides to industrial chemicals and even heavy metals. The mechanisms for nonmonotonicity discussed in *Section III.B* are likely explanations for the NMDRCs reported in a range of cell types after exposure to hormones and EDCs. Table 6 provides only a small number of examples from the literature, and it should be noted that because these are studies of cells in culture, most of these studies typically examined only a few types of outcomes: cell number (which could capture the effects of a chemical on cell proliferation, apoptosis, or both), stimulation or release of another hormone, and regulation of target protein function, often examined by measuring the phosphorylation status of a target.

2. Examples of NMDRCs in animal studies

Some scientists suggest that nonmonotonicity is an artifact of cell culture, however, a large number of NMDRCs have been observed in animals after administration of natural hormones and EDCs, refuting the hypothesis that this is a cell-based phenomenon only. Similar to what has been observed in cultured cells, the NMDRCs observed in animals also span a large range of chemicals, model organisms, and affected endpoints (Table 7). These results underscore the biological importance of the mechanisms of nonmonotonicity that have been largely worked out *in vitro*.

Although NMDRCs attributable to estrogen treatment are well documented, the induction of NMDRCs is again observed to be a general feature of hormone treatment; a wide range of hormones produce these types of responses in exposed animals. Importantly, a number of pharmaceutical compounds with hormone-mimicking or endocrine-disrupting activities also produce NMDRCs. Finally, as expected from the results of cell culture

TABLE 6. Examples of NMDRCs in cell culture experiments

Chemicals by chemical class	Nonmonotonic effect	Cell type	Refs.
Natural hormones			
17β-Estradiol	Cell number	MCF7 breast cancer cells	135, 716
	Dopamine uptake	Fetal hypothalamic cells (primary)	717
	pERK levels, prolactin release	GH3/B6/F10 pituitary cells	41, 718, 719
	β-Hexosaminidase release	HMC-1 mast cells	720
	Cell number	Vascular smooth muscle cells	721
	Production of L-PGDS, a sleep-promoting substance	U251 glioma cells	722
5α-Dihydrotestosterone	Cell number	LNCaP-FGC prostate cancer cells	499
	Cell number, kinase activity	Vascular smooth muscle cells	721
5α-Androstenedione	Cell number	LNCaP-FGC prostate cancer cells	499
Corticosterone	Mitochrondrial oxidation, calcium flux	Cortical neurons (primary)	723
Insulin	Markers of apoptosis (in absence of glucose)	Pancreatic β-cells (primary)	724
Progesterone	Cell number	LNCaP-FGC prostate cancer cells	499
Prolactin	Testosterone release	Adult rat testicular cells (primary)	725
hCG	Testosterone release	Adult rat testicular cells (primary)	725
T_3	Rate of protein phosphorylation	Cerebral cortex cells (primary, synaptosomes)	726
	LPL mRNA expression	White adipocytes (rat primary)	727
GH	*IGF-I* expression	Hepatocytes (primary cultures from silver sea bream)	728
Pharmaceutical hormones			
DES	Cell number	MCF7 breast cancer cells	716
	Prolactin release	GH3/B6/F10 pituitary cells	41
Ethinyl estradiol	CXCL12 secretion	MCF7 breast cancer cells, T47D breast cancer cells	729
R1881 (synthetic androgen)	Cell number	LNCaP-FGC cells	499
Trenbolone	Induction of micronuclei	RTL-W1 fish liver cells	730
Plastics			
BPA	Cell number	MCF7 breast cancer cells	135, 716
	Dopamine efflux	PC12 rat tumor cells	40
	pERK levels, intracellular Ca^{2+} changes, prolactin release	GH3/B6/F10 pituitary cells	41, 718
	Cell number	LNCaP prostate cancer cells	731
DEHP	Number of colonies	*Escherichia coli* and *B. subtilis* bacteria	732
Di-*n*-octyl phthalate	Number of colonies	*E. coli* and *B. subtilis* bacteria	732
Detergents, surfactants			
Octylphenol	Cell number	MCF7 breast cancer cells	716
	Dopamine uptake	Fetal hypothalamic cells (primary)	717
	pERK levels	GH3/B6/F10 pituitary cells	718
	hCG-stimulated testosterone levels	Leydig cells (primary)	733
Propylphenol	pERK levels	GH3/B6/F10 pituitary cells	718
Nonylphenol	pERK levels, prolactin release	GH3/B6/F10 pituitary cells	41, 718
	β-Hexosaminidase release	HMC-1 mast cells	720
	Cell number	MCF7 breast cancer cells	135
PAH			
Phenanthrene	All-trans retinoic acid activity	P19 embryonic carcinoma cells	734, 735
Benz(a)acridine	All-trans retinoic acid activity	P19 embryonic carcinoma cells	734
Naphthalene	hCG-stimulated testosterone	Pieces of goldfish testes	736
Β-naphthoflavone	hCG-stimulated testosterone	Pieces of goldfish testes	736
Retene	hCG-stimulated testosterone	Pieces of goldfish testes	736
Heavy metals			
Lead	Estrogen, testosterone, and cortisol levels	Postvitellogenic follicles (isolated from catfish)	737
Cadmium	Expression of angiogenesis genes	Human endometrial endothelial cells	738

(*Continued*)

TABLE 6. Continued

Chemicals by chemical class	Nonmonotonic effect	Cell type	Refs.
Phytoestrogens and natural antioxidants			
Genistein	Cell number	Caco-2BBe colon adenocarcinoma cells	739
	CXCL12 secretion, cell number	T47D breast cancer cells	729
	Cell number, cell invasion, MMP-9 activity	PC3 prostate cancer cells	740
	pJNK levels, Ca^{2+} flux	GH3/B6/F10 pituitary cells	719
Coumesterol	Prolactin release, pERK levels	GH3/B6/F10 pituitary cells	719
Daidezin	Prolactin release, pERK levels	GH3/B6/F10 pituitary cells	719
	Cell number	MCF7 breast cancer cells	135
	Cell number	LoVo colon cancer cells	741
Resveratrol	Expression of angiogenesis genes	Human umbilical vein endothelial cells	742
Trans-resveratrol	pERK levels, Ca^{2+} flux	GH3/B6/F10 pituitary cells	719
Artelastochromene	Cell number	MCF7 breast cancer cells	743
Carpelastofuran	Cell number	MCF7 breast cancer cells	743
Biochanin A	Induction of estrogen-sensitive genes in the presence of testosterone	MCF7 breast cancer cells	744
Licoflavone C	Induction of estrogen-sensitive genes	Yeast bioassay	745
Quercetin	Aromatase activity	H295R adrenocortical carcinoma cells	746
	Cell number	SCC-25 oral squamous carcinoma cells	747
Dioxin			
TCDD	Cell number, gene expression	M13SV1 breast cells	748
PCB			
PCB-74	Cell viability, GnRH peptide levels	GT1-7 hypothalamic cells	749
PCB-118	Cell viability, GnRH peptide levels	GT1-7 hypothalamic cells	749
Aroclor 1242 (PCB mixture)	β-Hexosaminidase release	HMC-1 mast cells	720
POP mixture	Apoptosis of cumulus cells	Oocyte-cumulus complexes (primary, isolated from pigs)	750
Herbicides			
Glyphosphate-based herbicide (Round-Up)	Cell death, aromatase activity, ERβ activity	HepG2 liver cells	751
Atrazine	Cell number	IEC-6 intestinal cells	752
Insecticides			
Endosulfan	Cell number	IEC-6 intestinal cells	752
	β-Hexosaminidase release	HMC-1 mast cells	720
	ATPase activity of P-glycoprotein	CHO cell extracts	753
Diazinon	Cell number	IEC-6 intestinal cells	752
Dieldrin	β-Hexosaminidase release	HMC-1 mast cells	720
DDT	Cell number	MCF7 breast cancer cells	144
DDE	β-Hexosaminidase release	HMC-1 mast cells	720
	Prolactin release	GH3/B6/F10 pituitary cells	41
3-Methylsulfonyl-DDE	Cortisol and aldosterone release, expression of steroidogenic genes	H295R adrenocortical carcinoma cells	754
Fungicides			
Hexachlorobenzene	Transcriptional activity in the presence of DHT	PC3 prostate cancer cells	755
Prochloraz	Aldosterone, progesterone, and corticosterone levels; expression of steroidogenic genes	H295R adrenocortical cells	756
Ketoconazole	Aldosterone secretion	H295R adrenocortical cells	757
Fungicide mixtures	Aldosterone secretion	H295R adrenocortical cells	757
PBDE			
PBDE-49	Activation of ryanodine receptor 1	HEK293 cell (membranes)	758
PBDE-99	Expression of *GAP43*	Cerebral cortex cells (primary)	759

Due to space concerns, we have not elaborated on the shape of the curve (U, inverted U, or other nonmonotonic shape) or the magnitude of observed effects in this table. CXCL12, Chemokine (C-X-C motif) ligand 12; DEHP, bis(2-ethylhexyl) phthalate; DHT, dihydrotestosterone; hCG, human chorionic gonadotropin; MMP, matrix metalloproteinase; PAH, polyaromatic hydrocarbons; PBDE, polybrominated diphenyl ethers; PCB, polychlorinated biphenyl; pERK, phospho-ERK; PGDS, prostaglandin-D synthase; pJNK, phospho-c-Jun N-terminal kinase.

TABLE 7. Examples of NMDRCs in animal studies

Chemicals by chemical class	Nonmonotonic effect	Organ/sex/animal	Refs.
Natural hormones			
17β-Estradiol	Morphological parameters	Mammary gland/female/mice	138, 541
	Accumulation of cAMP	Pineal/female/rats	760
	Prostate weight	male/mice	689
	Uterine weight	female/mice	761
	Antidepressant effects, measured by immobility assay	Behavior/male/mice	762
	Nocturnal activity, gene expression in preoptic area	Brain and behavior/female/mice	763
Corticosterone	Spatial memory errors	Behavior/male/rats	764
	Cholinergic fiber loss in cortex after treatment with neurodegenerative drugs	Brain/male/rats	765
	Mitochondrial metabolism	Muscle/male/rats: strain differences	766
	Contextual fear conditioning	Behavior/male/rats	767
	Locomotor activity	Behavior/male/captive Adelie penguins	768
Glucocorticoid	Na^+/K^+-ATPase activity	Brain/tilapia (fish)	769
Testosterone	Na^+/K^+-ATPase activity	Brain/tilapia (fish)	769
	Gonadotropin subunit gene expression	Pituitary/sexually immature goldfish	770
11β-Hydroxyandrosterone	Gonadotropin subunit gene expression	Pituitary/sexually immature goldfish	770
T_4	Bone growth	Tibia/male/rats with induced hypothyroidism	771
Leptin	Insulin production (in the presence of glucose)	Pancreas/male/rats	560
Oxytocin	Infarct size, plasma LDH levels, creatine kinase activity after ischemia/ reperfusion injury	Brain and blood/male/rats	772
	Memory retention	Behavior/male/mice	773
Melatonin	Brain infarction and surviving neuron number after injury	Brain/female/rats	774
Dopamine	Memory	Brain/both/rhesus monkey	775
	Neuronal firing rate	Brain/male/rhesus monkey	776
Pharmaceutical			
DES	Sex ratio, neonatal body weight, other neonatal development	Mice	777
	Adult prostate weight	Male/mice	689
	Uterine weight	Female/mice	761
	Expression of PDGF receptor	Testes/male/rats	778
	Morphological parameters	Mammary gland/male and female/ mice	779
Estradiol benzoate	Dorsal prostate weight, body weight	Male/rats	780
	Sexual behaviors, testes morphology	Male/zebra finches (birds)	781
Ethinyl estradiol	GnRH neurons	Brain/zebrafish	782
Tamoxifen	Uterine weight	Female/mice	761
Fluoxetine (antidepressant)	Embryo number	*Potamopyrgus antipodarum* (snails)	783
Fadrozole (aromatase inhibitor)	Aromatase activity	Ovary/female/fathead minnows	784
Plastics			
BPA	Fertility	Reproductive axis /female/mice	316
	Reproductive behaviors	Behavior/male/rats	785
	Protein expression	Hepatopancreas/male/*Porcellio scaber* (isopod)	786
	Timing of vaginal opening, tissue organization of uterus	Reproductive axis/female/mice	577
	Expression of receptors in embryos	Brain and gonad/both/ mice	787
DEHP	Aromatase activity	Hypothalamus/male/rats	788
	Cholesterol levels	Serum/male/rats	569
	Timing of puberty	Reproductive axis /male/rats	789
	Body weight at birth, vaginal opening, and first estrous	Female/rats	790
	Seminal vesicle weight, epididymal weight, testicular expression of steroidogenesis genes	Male/rats	791
	Responses to allergens, chemokine expression	Skin/male/mice	792

(*Continued*)

TABLE 7. Continued

Chemicals by chemical class	Nonmonotonic effect	Organ/sex/animal	Refs.
Detergents, surfactants			
Nonylphenol ethoxylate	Fecundity	*Biomphalaria tenagophila* (snails)	793
Octylphenol	Embryo production	*P. antipodarum* (snails)	794
	Spawning mass and egg numbers	*Marisa cornuarietis* (snails)	795
Semicarbazide	Timing of preputial separation, serum DHT	Male/rats	796
Antimicrobial			
Triclocarban	Fecundity	*P. antipodarum* (snails)	797
PCB			
Mixture of PCB	Corticosterone levels	Male/kestrels (birds)	798
Environmental PCB mixture	Corticosterone levels	Female/tree swallows (birds)	799
UV filters			
Octyl methoxycinnamate	Activity, memory	Behavior/both/rats	800
Aromatic hydrocarbons			
Β-naphthoflavone	Testosterone	Plasma/male/goldfish	736
Toluene	Locomotor activity	Behavior/male/rats	801
Dioxins			
TCDD	Cell-mediated immunity	Immune system/male/ rats	802
	Proliferation after treatment with chemical carcinogen	Liver/female/rats	803
Heavy metals			
Cadmium	Expression of metallothionein, *pS2/TFF1*	Intestine and kidney/ female/rats	804
	Activity of antioxidant enzymes	Earthworms	805
	Size parameters, metamorphic parameters	*Xenopus laevis*	806
Lead	Growth, gene expression	*Vicia faba* seedlings (plant)	807
	Retinal neurogenesis	Eye and brain/female/rats	808
Selenium	DNA damage, apoptotic index	Prostate/male/dogs	809
	Hatching failure	Eggs/red-winged blackbirds (wild population)	810
Phytoestrogens			
Genistein	Aggressive, defensive behaviors	Behavior/male/mice	811
	Retention of cancellous bone after ovariectomy	Tibia bones/female/rat	812
	Expression of *OPN*, activation of Akt	Prostate/male/mice	740
Resveratrol	Angiogenesis	Chorioallantoic membrane/chicken embryos	742
	Ulcer index after chemical treatment, expression of gastroprotective genes	Stomach/male/mice	813
Phytochemicals			
Phlorizin	Memory retention	Behavior/male/mice	814
Herbicides			
Atrazine	Time to metamorphosis	Thyroid axis/*Rhinella arenarum* (South American toad)	815
	Survivorship patterns	Four species of frogs	363
	Growth parameters	*Bufo americanus*	816
Pendimethalin	Expression of *AR*, *IGF-I*	Uterus/female/mice	817
Commercial mixture with mecoprop, 2,4-dichlorophenoxyacetic acid and dicamba	Number of implantation sites, number of live births	Female/mice	818
Simazine	Estrous cyclicity	Reproductive axis/female/rat	819
Insecticides			
Permethrin	Dopamine transport	Brain/male/mice	820
Heptachlor	Dopamine transport	Brain/male/mice	820
DDT	Number of pups, sex ratios, neonatal body weight, male anogenital distance	Mice	777
Methoxychlor	Number of pups, anogenital distance (males and females), neurobehaviors (males and females)	Mice	777
Chlorpyrifos	Body weight	Male/rats	821
	Antioxidant enzyme activity	*Oxya chinensis* (locusts)	822
Malathion	Antioxidant enzyme activity	*O. chinensis* (locusts)	822

(*Continued*)

TABLE 7. Continued

Chemicals by chemical class	Nonmonotonic effect	Organ/sex/animal	Refs.
Fungicides			
Carbendazim	Liver enzymes, hematology parameters	Blood and liver/male/rats	823
Chlorothalonil	Survival, immune response, corticosterone levels	Several amphibian species	686
Vinclozolin	Protein expression	Testes/male/*P. scaber* (isopod)	786

Due to space concerns, we have not elaborated on the shape of the curve (U, inverted U, or other nonmonotonic shape) or the magnitude of observed effects in this table. DEHP, Bis(2-ethylhexyl) phthalate; DHT, dihydrotestosterone; LDH, lactate dehydrogenase; PCB, polychlorinated biphenyl; PDGF, platelet-derived growth factor.

experiments, chemicals with many different modes of action generate NMDRCs in treated animals.

Perhaps most striking is the range of endpoints affected, from higher-order events such as the number of viable offspring (which could be due to alterations in the reproductive tissues themselves or the reproductive axis), to behavioral effects, to altered organ weights, and to lower-order events such as gene expression. The mechanisms responsible for these nonmonotonic phenomena may be similar to those studied in cell culture systems, although additional mechanisms are likely to be operating *in vivo* such as alterations in tissue organization (541) and the interactions of various players in the positive and negative feedback loops of the endocrine system.

3. Examples of NMDRCs in the epidemiology literature

Perhaps not surprisingly, natural hormones produce NMDRCs in human populations as well (Table 8). Although the methods needed to detect NMDRCs in humans are specific to the field of epidemiology, these results sup-

TABLE 8. NMDRCs for natural hormones identified in the epidemiology literature

Hormone	Affected endpoint	NMDRC	Study subjects	Refs.
Testosterone (free)	Incidence of coronary events	Incidence of 25% at extremes of exposure, 16% at moderate exposure	Rancho Bernardo Study participants, women aged 40+ (n = 639)	824
	Depression	Hypo- and hypergonadal had higher depression scores than those with intermediate free testosterone	Androx Vienna Municipality Study participants, manual workers, men aged 43–67 (n = 689)	825
PTH	Mortality	~50% excess risk for individuals with low or high iPTH	Hemodialysis patients (n = 3946)	826
	Risk of vertebral or hip fractures	~33% higher for low or high iPTH compared to normal levels	Elderly dialysis patients (n = 9007)	827
TSH	Incidence of Alzheimer's disease	About double the incidence in lowest and highest tertile in women (no effects observed in men)	Framingham Study participants (elderly) (n = 1864, 59% women)	828
Leptin	Mortality	Mortality ~10% higher for lowest and highest leptin levels	Framingham Heart Study participants (elderly) (n = 818, 62% women)	563
Insulin	Coronary artery calcification	Higher for low and high insulin area under the curve measures.	Nondiabetic patients with suspected coronary heart disease, cross-sectional (n = 582)	829
	Mortality (noncardiovascular only)	Relative risk ~1.5 for highest and lowest fasting insulin levels	Helsinki Policemen Study participants, men aged 34–64 (n = 970)	830
Cortisol	BMI, waist circumference	Low cortisol secretion per hour for individuals with highest and lowest BMI, waist circumference	Whitehall II participants, adults, cross-sectional (n = 2915 men; n = 1041 women)	831
	Major depression (by diagnostic interview)	Slight increases at extremes of cortisol	Longitudinal Aging Study Amsterdam participants, aged 65+, cross-sectional (n = 1185)	832

BMI, Body mass index; iPTH, intact PTH; PTH, parathyroid hormone.

port the idea that NMDRCs are a fundamental feature of hormones. Importantly, it should be noted that most of the individuals surveyed in studies examining the effects of natural hormones have a disease status or are elderly. This of course does not mean that natural hormones induce NMDRCs in only these select populations but may instead be a reflection of the types of individuals available for these studies (for example, there are very few clinical events in younger people).

NMDRCs observed in the epidemiology literature from human populations exposed to EDCs are now starting to receive attention (Table 9). Here, most reports of NMDRCs come from studies of healthy individuals exposed to persistent organic pollutants POPs, chemicals that do not easily degrade and consequently bioaccumulate in human and animal tissues (542). These POPs do encompass a range of chemical classes including components of plastics, pesticides, and industrial pollutants. A large number of these studies have focused on endpoints that are relevant to metabolic disease, and together, these studies show that there is a recurring pattern of NMDRCs related to POPs and disease. Of course, not every study of POPs shows NMDRCs, and this is probably due to the distribution of EDCs in the populations examined.

In addition to the studies that show strong evidence for NMDRCs in human populations, there is also a subset of studies that provide suggestive evidence for nonmonotonic relationships between EDCs and human health endpoints (Table 9). In fact, the authors of many of these papers clearly identify U- or inverted U-shaped dose-response curves. However, when authors do not perform the appropriate statistical tests to verify the presence of a NMDRC, there is some ambiguity in their conclusions. The usual cross-sectional *vs.* prospective design dichotomy in epidemiology also is a factor that can influence the strength of a NMDRC, or prevent the detection of one at all. This disjunction in design is often incongruous with EDC exposure studies because we often know very little about clearance rates of the chemical, interactions with adiposity, and changes to these factors with age and gender. Yet regardless of any possible weaknesses in these studies, they provide supportive evidence that NMDRCs are observed in human populations.

Because these reports of NMDRCs in human populations are relatively new, few mechanisms have been proposed for these phenomena. Why would risk curves be nonmonotonic over the dose distribution observed in human populations? Why would individuals with the highest exposures have less severe health outcomes compared with individuals with more moderate exposures? One plausible explanation is that the same mechanisms for NMDRCs in animals and cell cultures operate in human populations: chronic exposures to high doses can activate negative feedback loops, activate receptors that promote changes in different pathways that diverge on the same endpoint with opposing effects, or produce some measure of toxicity. Accidental exposures of very large doses may not behave the same as background doses for a variety of reasons, including the toxicity of high doses; these large doses tend to occur over a short time (and therefore more faithfully replicate what is observed in animal studies after controlled administration).

Another explanation is that epidemiology studies, unlike controlled animal studies, examine truly complex mixtures of EDCs and other environmental chemicals. Some chemical exposures are likely to be correlated due to their sources and their dynamics in air, water, soil, and living organisms that are subsequently eaten. Therefore, intake of these chemicals may produce unpredicted, likely nonlinear outcomes whether the two chemicals act via similar or different pathways.

The design of observational epidemiological studies is fundamentally different from studies of cells or animals, in that the EDC exposure distributions are given, rather than set by the investigator. In particular, as shown in Fig. 5, different epidemiological populations will have different ranges of exposure, with the schematic example showing increasing risk in a population with the lowest exposures (labeled group A), an inverted U-shaped risk in a moderate dose population (labeled group B), and an inverse risk in a population with the highest exposures (labeled group C). An additional example is provided (labeled group D) in which an industrial spill shows high risk, but the comparison with the entire unaffected population with a wide variety of risk levels due to differential background exposure could lead to a high- or a low-risk reference group and a wide variety of possible findings.

It is reasonable to suggest that even though epidemiological studies are an assessment of exposures at a single time point, many of these pollutants are persistent, and therefore a single measure of their concentration in blood may be a suitable surrogate for long-term exposures. The movement of people from relatively low- to higher-exposure groups over time depend on refreshed exposures, clearance rates, and individual differences in ability to handle exposures (*i.e.* due to genetic susceptibilities, amount of adipose tissue where POPs can be stored, *etc.*).

Figure 5 therefore further illustrates that observational epidemiological studies yield the composite effect of varying mixtures of EDCs at various exposure levels for various durations, combining acute and chronic effects. These studies are important, however, in that they are the only way to study EDC effects in the long term in intact humans, as opposed to studying signaling pathways, cells,

TABLE 9. NMDRCs for EDCs identified in the epidemiology literature

Chemicals by chemical class	Affected endpoint	NMDRC	Study subjects	Refs.
Insecticides				
Trans-nonachlor	Diabetes incidence	Highest risk in groups with intermediate exposures (quartile 2)	CARDIA participants, case-control study (n = 90 cases and n = 90 controls)	833
	Telomere length in peripheral leukocytes	Increased length in intermediate exposures (quintile 4)	Adults aged 40+ (Korea, n = 84)	591
p,p′-DDE	BMI, triglyceride levels, HDL cholesterol	Highest risk in groups with intermediate exposures (quartile 3)	CARDIA participants (n = 90 controls from nested case control study)	590
	Risk of rapid infant weight gain	For infants born to women of normal weight prepregnancy, risk is highest with intermediate exposures.	Infants from Childhood and the Environment project, Spain (n = 374 from normal prepregnancy weight mothers; n = 144 from overweight mothers)	834
	Telomere length in peripheral leukocytes	Increased length with intermediate exposures (quintile 4)	Adults aged 40+ (Korea, n = 84)	591
Oxychlordane	Bone mineral density of arm bones	With low exposures, fat mass had inverse associations with bone mineral density; with high exposures, fat mass had positive associations with bone mineral density.	NHANES 1999–2004 participants, aged 50+ (n = 679 women, n = 612 men)	835
Plastics				
Mono-methyl phthalate (MMP)	Atherosclerotic plaques	Increased risk in intermediate exposure groups (quintiles 2–4)	Adults aged 70, living in Sweden (n = 1016)	836
Perfluorinated compounds				
PFOA	Arthritis (self-reported)	Increased risk in intermediate exposure groups (quartile 2)	NHANES participants, aged 20+ (both sexes, n = 1006)	837
Fire retardants				
PBB-153	Blood triglyceride levels	Increased risk in intermediate exposure groups (quartile 2)	NHANES participants, aged 12+ (n = 637)	604
PBDE-153	Prevalence of diabetes,	Prevalence of diabetes highest in intermediate groups (quartiles 2–3 relative to individuals with undetectable levels)	NHANES participants, aged 12+ (n = 1367)	604
	Prevalence of metabolic syndrome, levels of blood triglycerides	Prevalence of metabolic syndrome highest in intermediate exposure groups (quartile 2 relative to individuals with undetectable levels); blood triglycerides highest in low exposure groups (quartile 1 relative to individuals with undetectable levels)	NHANES participants, aged 12+ (n = 637)	604
PCB				
PCB-74	Triglyceride levels	Lowest levels are observed in intermediate groups (quartile 2)	CARDIA participants (n = 90 controls from nested case-control study)	590
PCB-126	Bone mineral density in right arm	With low exposures, fat mass had inverse associations with bone mineral density; with high exposures, fat mass had positive associations with bone mineral density	NHANES participants, aged <50 (n = 710 women, n = 768 men)	835
PCB-138	Bone mineral density in right arm	With low exposures, fat mass had inverse associations with bone mineral density; with high exposures, fat mass had positive associations with bone mineral density	NHANES participants, women aged 50+ (n = 679 women, n = 612 men)	835
PCB-153	Telomere length in peripheral leukocytes	Increased length with intermediate exposure groups (quintile 4)	Adults aged 40+ (Korea, n = 84)	591
PCB-170	Diabetes incidence	Highest risk in groups with intermediate exposures (quartile 2)	CARDIA participants, case-control study (n = 90 cases and n = 90 controls)	833
	Endometriosis	Decreased risk in groups with intermediate exposures (quartile 3)	Participants from the Women at Risk of Endometriosis (WREN) study, 18–49 yr old, case-control study (n = 251 cases; n = 538 controls)	838
PCB-172	DNA hypomethylation (by Alu assay)	Highest levels of hypomethylation in groups with lowest and highest exposures	Adults aged 40+ (Korea, n = 86)	839
PCB-180[a]	BMI	Highest BMI with intermediate exposures (quartile 2)	CARDIA participants (n = 90 controls from nested case control study)	590
PCB-187[a]	HDL cholesterol levels	Lowest levels with intermediate exposures (quartile 2)	CARDIA participants (n = 90 controls from nested case control study)	590
PCB 196–203	Diabetes incidence	Highest risk in groups with intermediate exposures (quartile 2)	CARDIA participants, case-control study (n = 90 cases and n = 90 controls)	833
PCB-196	Endometriosis	Decreased risk in groups with intermediate exposures (quartile 3)	Participants from the Women at Risk of Endometriosis (WREN) study, 18–49 yr old, case-control study (n = 251 cases; n = 538 controls)	838

(*Continued*)

TABLE 9. Continued

Chemicals by chemical class	Affected endpoint	NMDRC	Study subjects	Refs.
PCB-199[a]	Triglyceride levels	Highest risk in groups with intermediate exposures (quartiles 2–3)	CARDIA participants (n = 90 controls from nested case control study)	590
PCB-201	Endometriosis	Decreased risk in groups with intermediate exposures (quartiles 2–3)	Participants from the Women at Risk of Endometriosis (WREN) study, 18–49 yr old, case-control study (n = 251 cases, n = 538 controls)	838
Heavy metals				
Selenium	Fasting glucose levels (by modeled exposure)	Intermediate exposures have highest fasting glucose levels	NHANES 2003- 2004 participants, aged 40+ (n = 917)	840
	Glycosylated hemoglobin (by modeled exposure)	Intermediate exposures have highest % glycosylated hemoglobin	NHANES 2003- 2004 participants, aged 40+ (n = 917)	840
	Diabetes incidence (by modeled exposure)	Intermediate exposures have highest risk for diabetes	NHANES 2003- 2004 participants, aged 40+ (n = 917)	840
	Blood triglyceride levels	Intermediate exposures have highest triglyceride levels	NHANES participants, aged 40+ (n = 1159)	841
Arsenic	Cytokines in umbilical cord blood	Lower inflammatory markers at intermediate exposures (quartile 2)	Pregnant women in Bangladesh (n = 130)	842
Manganese	Mental development scores in infants and toddlers	Intermediate exposures had highest mental development scores at 12 months of age; association lost in older toddlers	12-month-old infants, Mexico (n = 301)	843
	Sperm count, motility and morphology	Intermediate doses had lowest sperm counts and motility; intermediate doses also had the worst sperm morphologies	Men aged 18–55 (infertility clinic patients, n = 200)	844
Mixtures				
31 POP	Diabetes incidence	Highest incidence in intermediate groups (sextiles 2–3)	CARDIA participants, case-control study (n = 90 cases and n = 90 controls)	833
16 POP	Diabetes incidence	Highest incidence in intermediate groups (sextiles 2–3)	CARDIA participants, case-control study (n = 90 cases and n = 90 controls)	833
Non-dioxin-like PCB (mix)	Metabolic syndrome	Highest incidence in intermediate groups (quartile 3)	NHANES 1999–2002 participants, aged 20+ (n = 721)	845
Dioxin-like PCB (mix)	Triacylglycerol levels by quartile of exposure	Highest levels in intermediate groups (quartile 3)	NHANES 1999–2002 participants, aged 20+ (n = 721)	845
		Additional supportive evidence for NMDRC in the epidemiology literature		
Insecticides				
Heptachlor epoxide	Prevalence of newly diagnosed hypertension	Highest risk in intermediate groups (quartile 2); other endpoints do not have NMDRC	NHANES participants, women aged 40+, cross-sectional (n = 51 cases, n = 278 total)	826
β-Hexachloro-cyclohexane	Triacylglycerol levels by quartile of exposure	Highest risk in intermediate group (quartile 2)	NHANES participants, aged 20+ (n = 896 men, 175 with metabolic syndrome)	845
Plastics				
Mono-*N*-butyl phthalate (MBP)	BMI, age-specific effects	Effects seen only in elderly participants (age 60–80); risk is lowest in quartile 3	NHANES male participants (n = 365; age 60–80)	470
Mono-benzyl phthalate (MBzP)	BMI, age-specific effects	Effects seen only in young participants (age 6–11); risk is highest in quartiles 2–3	NHANES participants (both sexes, n = 329 males; n = 327 females)	470
Flame retardants				
PFOA	Thyroid disease (self-reported)	Lowest risk in intermediate groups (quartile 3)	NHANES 1999–2000, 2003–2006 participants, males aged 20+ (n = 3974)	837
Dioxin and related compounds				
TCDD	Age at natural menopause	Highest for intermediate exposure group (quintile 4)	Highly exposed women; Seveso Women's Health Study participants (n = 616)	468
HCDD	Bone mineral density in right arm by quintile of fat mass	With low exposures, fat mass had inverse associations with bone mineral density; with high exposures, fat mass had positive associations with bone mineral density	NHANES participants, women aged 50+ (n = 679 women, n = 612 men)	835
Heavy metals				
Selenium	Prevalence of peripheral artery disease	Disease prevalence decreased in intermediate doses, then increased gradually with higher doses	NHANES participants, aged 40+ (n = 2062)	469

BMI, Body mass index; HCDD, hexachloro-dibenzo-p-dioxin; HDL, high-density lipoprotein. PCB, polychlorinated biphenyls; PFOA, perfluorooctanoic acid; PBB, polybrominated biphenyl; PBDE, polybrominated diphenyl ethers; POP, persistent organic pollutants

[a] In many cases, multiple chemicals in the same class had similar effects. A few chemicals were selected to illustrate the observed effect. This list is not comprehensive.

organs, or animal models over limited periods of time. Causal inference is not done directly from the epidemiological study results; instead, it is done via combining information from the epidemiological observations with findings from the detailed studies of pathways and animals.

We have suggested that NMDRCs are a fundamental and general feature of hormone action in cells and animals.

Figure 5.

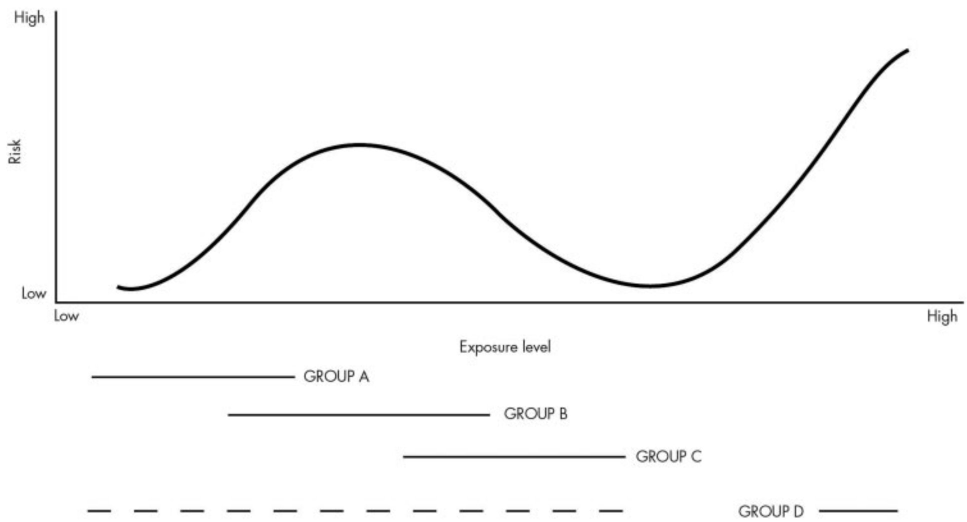

Figure 5. Example of a NMDRC in humans and the sampling populations that could be examined in epidemiology studies. This schematic illustrates a theoretical NMDRC in a human population. If a study were to sample only group A, the conclusion would be that with increasing exposures, risk increases monotonically. Sampling group B would allow researchers to conclude that there is a nonmonotonic relationship between exposure level and risk. If a study included only group C, the conclusion would be that with increasing exposures, there is decreased risk of disease. Group D represents a population that was highly exposed, *i.e.* due to an industrial accident. This group has the highest risk, and there is a monotonic relationship between exposures and risk, although risk is high for all individuals. In the group D situation, there is generally a background population with which high-dose exposure is compared (*dotted line*); relative risk for group D would depend on whether that background population resembles group A, B, or C. From this example, it is clear that the population sampled could strongly influence the shape of the dose-response curve produced as well as the conclusions reached by the study.

It is therefore worth asking whether NMDRCs are expected in the epidemiology literature. The endpoints assessed in epidemiology studies are typically integrated effects, rather than short-term effects; therefore, the various cell- or organ-specific effects may cancel each other, particularly if they are NMDRCs (because they are unlikely to all have nonmonotonicity at the same dose and direction). Thus, NMDRCs are likely to be rarer in the epidemiology literature compared with studies examining the effects of a wide range of doses of an EDC on animals and cultured cells. Yet it is also important to ask what can be concluded if a NMDRC is detected in one epidemiology study but not in others examining the same chemical and outcome. There are several factors that must be considered. The first is that differences in the populations examined between the two studies could explain why a monotonic relationship is observed in one group and a nonmonotonic relationship in another (see Fig. 5). The second is that one or more studies may not be statistically designed to detect NMDRCs. Finally, it is plausible that the NMDRC is an artifact due to residual confounding or some other factor that was not considered in the experimental design. As more becomes known about the mechanisms operating in cells, tissues, and organs to generate NMDRCs, our ability to apply this information to epidemiology studies will increase as well.

4. Tamoxifen flare, a NMDRC observed in cells, animals, and human patients

Although there is controversy in toxicology and risk assessment for endocrine disruptors, NMDRCs are recognized and used in current human clinical practice, although under a different specific term, flare. Flare is often reported in the therapy of hormone-dependent cancers such as breast and prostate cancer. Clinically, failure to recognize the NMDRC that is termed a flare would be considered malpractice in human medicine.

Tamoxifen flare was described and named as a transient worsening of the symptoms of advanced breast cancer, particularly metastases to bone associated with increased pain, seen shortly after the initiation of therapy in some patients (543). If the therapy could be continued, the patients showing tamoxifen flare demonstrated a very high likelihood of subsequent response to tamoxifen, including arrest of tumor growth and progression of symptoms for some time.

The subsequent mechanism of the flare was described in basic lab studies in athymic mouse models of human hormone-dependent breast cancer xenografts (544) and in tissue culture of hormone-dependent human breast cancer cells (545–547). In these models, it was observed that although high, therapeutic concentrations of tamoxifen inhibited estrogen-stimulated proliferation of breast cancer cells, lower concentrations of tamoxifen actually stimulated breast can-

Figure 6.

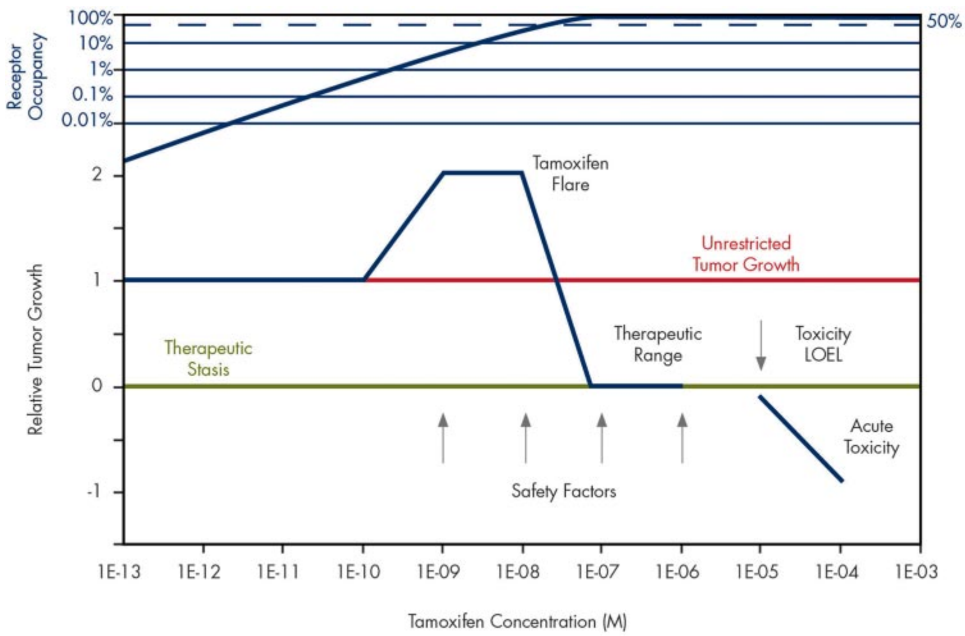

Figure 6. Dose-response ranges for tamoxifen in breast cancer therapy. This figure demonstrates the NMDRC, also called flare, in tamoxifen treatments. As the circulating dose of tamoxifen increases when treatment starts, patients initially experience flare, *i.e.* growth of the tumor (546), followed by a decrease in tumor size as the circulating levels of tamoxifen rise into the therapeutic range (676, 677). High doses of tamoxifen are acutely toxic (546). Starting from the highest concentrations, where acute toxicity is observed, and going to lower concentrations on the X-axis, the acute toxicity diminishes towards zero growth, *i.e.* therapeutic stasis (*green* baseline). This occurs at approximately 1E-05 m, the lowest observed effect level (LOEL) for toxicity. The vertical arrows show the results of applying three or four 10-fold safety factors to the LOEL for the high-dose toxicity of tamoxifen, and would calculate a safe or reference dose for tamoxifen in the region of flare, the least safe region of exposure in actual practice. Above the diagram of dose response ranges is estimated ER occupancy by tamoxifen. This was calculated from the affinity constant of tamoxifen for ERs determined in human breast cancer cells (Ki = 29.1 nM; Ref 678); flare appears to correspond to low receptor occupancy (*blue axis*), therapeutic range with mid and upper-range receptor occupancy, and acute toxicity well above 99% receptor occupancy. (678).

cer cell growth as long as the cells were estrogen dependent (548). Tamoxifen was also shown to disrupt tissue organization of the mammary gland, with specific effects on the stroma that may contribute to the observed effects on proliferation of epithelial cells (549, 550).

Tamoxifen therapy is administered as 10 mg twice per day (20 mg/d; approx 0.3 mg/kg body weight per day), but the target circulating levels are in the near submicromolar range (0.2–0.6 μM); these levels are reached slowly, after approximately 2 wks of therapy (551). In the initial period, where tamoxifen flare is observed, the circulating concentrations are ascending through lower concentrations, in the range below therapeutic suppression of growth, where breast cancer cell proliferation is actually stimulated by the drug, both in tissue culture, in animal xenograft studies, and in human patients (reviewed in Ref. 548). The recognition of this dual dose-response range for tamoxifen (low-dose, low-concentration estrogenic growth-stimulatory and higher-dose, higher-concentration estrogenic growth-inhibitory responses) led to the definition of the term selective estrogen response modulator, or SERM, activity (552–554). This SERM activity has since been observed for many or even most estrogenic EDCs, including BPA (3, 555–557).

These observations defined three separate dose-response ranges for the SERM tamoxifen in human clinical use. The lowest dose-response range, the range of flare, stimulated breast cancer growth and symptoms in some patients with hormone-dependent cancer. The next higher dose-response range is the therapeutic range where tamoxifen inhibits estrogen-dependent tumor growth. The highest dose range causes acute toxicity by the SERM (see Fig. 6).

Tamoxifen provides an excellent example for how high-dose testing cannot be used to predict the effects of low doses. For tamoxifen (as for other drugs), the range of acute human toxicity for tamoxifen was determined in phase I clinical trials. Phase I trials also defined an initial therapeutic range, the second dose-response range, as a dose below which acute toxicity was not observed. The therapeutic dose range was tested and further defined in phase II and later clinical trials to determine efficacy (see for example Ref. 558). Standard toxicological testing from

Figure 7.

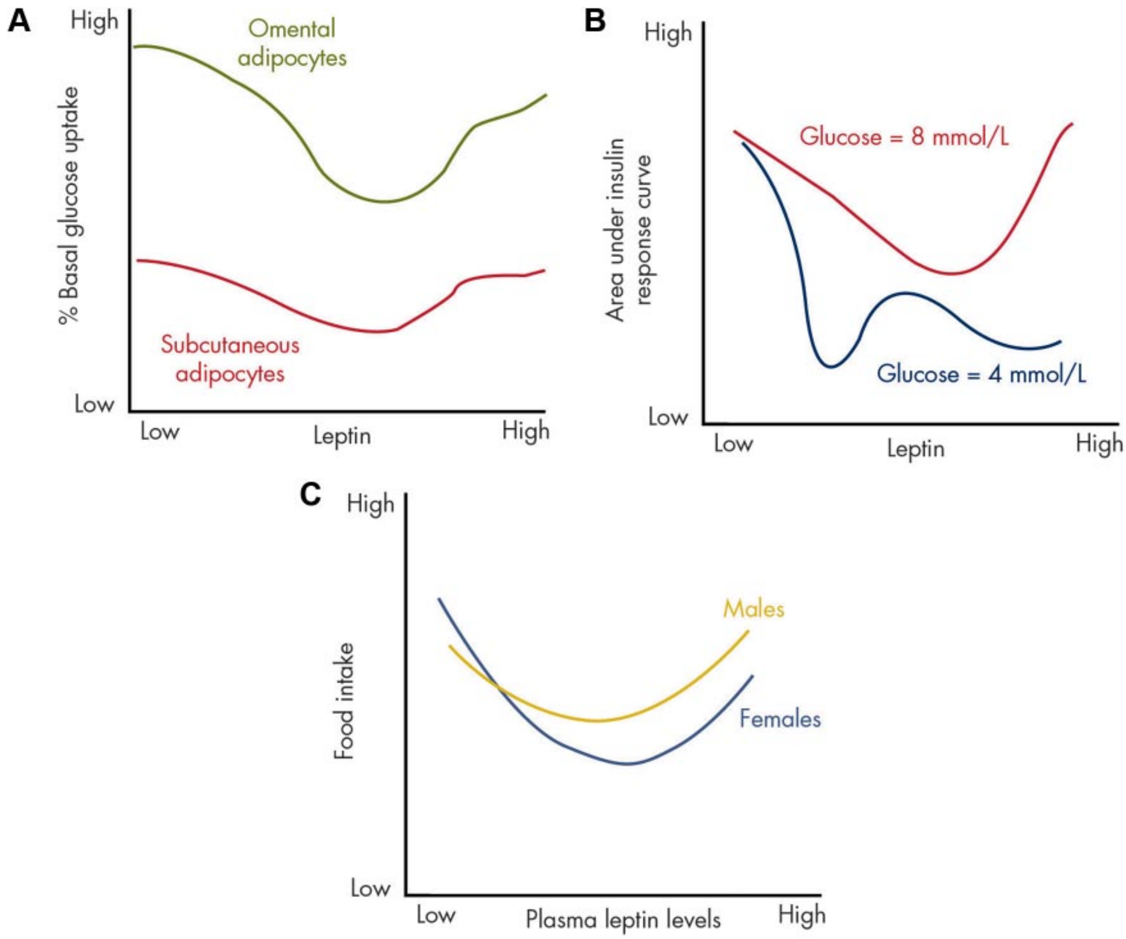

Figure 7. Leptin as an example of a NMDRC. Several studies report NMDRCs in response to leptin treatments. A, NMDRCs are observed in cultured primary adipocytes after leptin exposure. This graph illustrates the relationship between administered leptin dose and glucose uptake in two types of adipocytes, those isolated from omental tissue (*green*) and others from sc fat (*purple*) (schematic was made from data in Ref. 559). These data are on a log-linear plot. B, *Ex vivo* rat pancreas was treated with leptin and various doses of glucose, and the insulin response curves were examined. Area under the curve is a measure of the ability of the pancreas to bring glucose levels under control. Different dose-response curves were observed depending on the amount of glucose administered: a U-shaped curve when 8 mmol/liter was included (*pink*) or a multiphasic curve with 4 mmol/liter (*blue*) (schematic made from data in Ref. 560). These data are on a linear-linear plot. C, U-shaped NMDRCs were also observed when food intake was compared with leptin levels in the blood of rats administered the hormone. This response was similar in males (*orange*) and females (*cyan*) (schematic made from data in Ref. 562). These data are on a linear-linear plot.

high doses to define a LOAEL or NOAEL are equivalent to the phase I clinical testing, and in risk assessment, a safe dose or reference dose is calculated from these tests. However, the lowest dose range, with the highly adverse effects termed flare, was not detected in the phase I trials and was determined only for tamoxifen in breast cancer therapy at the therapeutic doses (543). The implication for risk assessment is that NMDRCs for EDCs, particularly those already identified as SERMs, would likely not be detected by standard toxicological testing at high doses. That is, the consequence of high-dose testing is the calculation of a defined but otherwise untested safe dose that is well within the range equivalent to flare, *i.e.* a manifestly unsafe dose of the EDC (Fig. 6).

5. Similarities in endpoints across cell culture, animal, and epidemiology studies: evidence for common mechanisms?

There are common trends in some findings of NMDRCs in cell, animal, and human studies and therefore evidence for related mechanisms for NMDRCs at various levels of biological complexity. Tamoxifen flare, discussed in *Section III.C.4*, is an informative example. Another illustrative example is that of the effect of the hormone leptin (Fig. 7). In cultured primary adipocytes, NMDRCs are observed after leptin exposure; moderate doses of leptin significantly reduce insulin-mediated glucose intake, whereas low and high doses maintain higher glucose intake in response to insulin (559). The rat pancreas shows a similar response to leptin; the amount of secreted insulin has an inverted U-shaped response to leptin (560, 561). Even more striking is the relationship between leptin and food intake. Rats administered moderate doses of leptin consume less food compared to rats dosed with low or high levels of leptin (562); mechanistically, this lower food intake could be due to higher circulating glucose levels in these animals due to ineffective insulin action. And finally, in a human study, leptin levels were found to correlate with body mass index but have a U-shaped relationship with mortality (563). These results suggest that hormones can produce similar responses at several levels of biological complexity (cell, organ, animal, and population).

A large number of epidemiology studies with NMDRCs have found relationships between EDC exposures like POPs and metabolic diseases including obesity and diabetes (Table 9) (see also Ref. 564 for a review), and the mechanisms for these relationships have begun to be explored. Human and animal cells treated with EDCs in culture display NMDRCs that are relevant to these diseases: BPA has nonmonotonic effects on the expression of adipocyte proteins in preadipocytes and the release of adiponectin from mature adipocytes (565–567). Similarly, in female rodents, low doses but not high doses of BPA increased adipose tissue weight and serum leptin concentrations (568), and intermediate doses of phthalates decrease serum cholesterol levels (569). Thus, although understanding the mechanisms operating at the cellular level of organization has not yet led to definitive knowledge of the mechanisms producing NMDRCs in human populations, there appear to be strong similarities in cells, animals, and humans that support a call for continued work focusing on metabolic disease endpoints at each level of biological organization.

D. NMDRC summary

We have demonstrated that nonmonotonicity is a common occurrence after exposures to hormones and EDCs in cell culture and animals and across human populations. Because of the abundance of examples of NMDRCs, we expect that if adequate dose ranges are included in animal and cell culture studies, including the use of negative and well-chosen positive controls, NMDRCs may be observed more often than not. Here, we have focused mainly on studies that examined a wide range of doses, including many that examined the effects of doses that span the low-dose and toxicological ranges. We also discussed several mechanisms that produce NMDRCs. Each of these mechanisms can and does operate at the same time in a biological system, and this cooperative action is ultimately responsible for NMDRCs.

Understanding nonmonotonicity has both theoretical and practical relevance. When a chemical produces monotonic responses, all doses are expected to produce similar effects whose magnitude varies with the dose, but when a chemical produces a NMDRC, dissimilar or even opposite effects will be observed at different doses. Thus, monotonic responses can be modeled using the assumption that each step in a linear pathway behaves according to the law of mass action (43, 570); high doses are always expected to produce higher responses. In contrast, NMDRCs are not easy to model (although they are quite easy to test for), requiring detailed knowledge of the specific mechanisms operating in several biological components. From a regulatory standpoint, information from high doses cannot always be used to assess whether low doses will produce a biological effect (38).

IV. Implications of Low-Dose Effects and Nonmonotonicity

Both low-dose effects and NMDRCs have been observed for a wide variety of EDCs as well as natural hormones. Importantly, these phenomena encompass every level of biological organization, from gene expression, hormone production, and cell number to changes in tissue architecture to behavior and population-based disease risks. One conclusion from this review is that low-dose effects and NMDRCs are often observed after administration of environmentally relevant doses of EDCs. For both hormones and EDCs, NMDRCs should be the default assumption absent sufficient data to indicate otherwise. Furthermore, there are well-understood mechanisms to explain how low-dose effects and NMDRCs manifest *in vitro* and *in vivo*. Accepting these phenomena, therefore, should lead to paradigm shifts in toxicological studies and will likely also have lasting effects on regulatory science. Some of these aspects are discussed below. Additionally, we have briefly explored how this knowledge should influence future approaches in human and environmental health.

At a very practical level, we recommend that researchers publishing data with low-dose and nonmonotonic effects include key words in the abstract/article that identify them as such specifically. This review was unquestionably impeded because this has not been standard practice. We also strongly recommend that data showing nonmonotonic and binary response patterns not be rejected or criticized because there is no dose response.

A. Experimental design

1. Dose ranges must be chosen carefully

To detect low-dose effects or NMDRCs, the doses included for testing are of utmost importance. Most of the studies we examined here for nonmonotonicity tested doses over severalfold concentrations. Unfortunately, regulatory guidelines only require that three doses be tested. Both low-dose effects and NMDRCs can be observed when examining only a few doses, but some studies may detect significant results purely by luck, because a small shift in dose can have a large impact on the ability to observe differences relative to untreated controls.

In the multitude of chemicals that have never been tested at low doses, or in the development of new chemicals, to determine whether a chemical has low-dose effects in laboratory animals, we suggest setting the NOAEL or LOAEL from traditional toxicological studies as the highest dose in experiments specifically designed to test endocrine-sensitive endpoints. We suggest setting the lowest dose in the experiment below the range of human exposures, if such a dose is known. Several intermediate doses overlapping the range of typical human exposures should be included also, bringing the total number in the range of five to eight total doses tested. Importantly, although the levels of many environmental chemicals in human blood and/or urine have been reported by the CDC and other groups responsible for population-scale biomonitoring, it is often not known what administered doses are needed to achieve these internal exposure levels in animals (4, 253); thus, toxicokinetic studies are often needed before the onset of low-dose testing. This is important because the critical issue is to determine what effects are observed in animals when circulating levels of an EDC match what is measured in the typical human. Due to differences in metabolism, route of exposure, and other factors, a relatively high dose may need to be administered to a rodent to produce blood concentrations in the range of human levels; however, this should not be considered a high-dose study.

It has also been suggested that animal studies that are used to understand the potential effects of a chemical on humans should use a relevant route of administration to recapitulate human exposures (571, 572) because there may be differences in metabolism after oral and nonoral administration. Many chemicals that enter the body orally undergo first-pass metabolism and are then inactivated via liver enzymes, whereas other routes (*i.e.* sc) can bypass these mechanisms and lead to a higher concentration of the active compound in circulation (573). Studies indicate, however, that inactivation of chemicals via first-pass metabolism is not complete and also that deconjugation of metabolites can occur in some tissues allowing the re-release of the active form (574, 575). Additionally, for some chemicals, it is clear that route of administration has little or no impact on the availability of the active compound in the body (241, 384), and other studies show that route of administration has no impact on the biological effects of these chemicals; *i.e.* regardless of how it enters the body, dioxin has similar effects on exposed individuals (384), and comparable results have been observed for BPA (141). Although understanding the typical route of human exposure to each environmental chemical is an important task, it has been argued that any method that leads to blood concentrations of a test chemical in the range they are observed in humans is an acceptable exposure protocol, and this is especially true with gestational exposures, because fetuses are exposed to chemicals only via their mothers' blood (31, 576).

2. Timing of exposures is important

Rodent studies indicate that EDC exposures during development have organizational effects, with permanent effects that can manifest even in late adulthood, whereas exposures after puberty are for the most part activational, with effects that are abrogated when exposures cease. For example, the adult uterus requires relatively large doses of BPA (in the parts-per-million range) to induce changes associated with the uterotrophic assay (555, 577), whereas parts-per-trillion and ppb exposures during the fetal period permanently and effectively alter development of the uterus (279, 310, 578). Thus, the timing of exposures is profoundly important to detect low-dose effects of EDCs.

Human studies also support this conclusion. The 1976 explosion of a chemical plant in Seveso, Italy, which led to widespread human exposure to large amounts of TCDD, a particularly toxic form of dioxin, and the deposition of this chemical on the land surrounding the chemical plant, provided evidence in support of the organizational and activational effects of endocrine-active chemicals in humans (579). Serum TCDD concentrations showed correlations between exposure levels and several disease outcomes including breast cancer risk, abnormal menstrual cycles, and endometriosis (580–582), but individuals who were either infants or teenagers at the time of the explosion were found to be at greatest risk for developing adult diseases (583, 584). Importantly, many scientists have argued that organizational effects can occur during puberty, *i.e.* that the period where hormones have irreversible effects on organ development extends beyond the fetal and neonatal period (585), and for some endpoints this appears to be the case (586, 587).

It has also been proposed that the endocrine system maintains homeostasis in the face of environmental insults (210). The adult endocrine system does appear to provide some ability to maintain a type of homeostasis; when the pharmaceutical estrogen DES is administered to pregnant mice, the circulating estradiol concentrations in the dam respond by decreasing linearly (224). In contrast, fetal concentrations of estradiol respond nonmonotonically in a way that is clearly not correlated with maternal levels. Similarly, there is evidence that BPA can induce aromatase and therefore increase estradiol levels *in situ* in the fetal urogenital sinus (588). This is an example of a feed-forward positive-feedback effect rather than a homeostatic response. The effects of EDCs on adult subjects, both animal and people, suggest that diseases often result from low-dose adult exposures (589–595); this argues against a view of the endocrine system as a means to maintain homeostatic control. Instead, individuals can be permanently changed, in an adverse way, after EDC exposures.

In one example, pregnant mice were exposed to low concentrations of BPA, and their male offspring had altered pancreatic function at 6 months of age (158). Surprisingly, however, the mothers (exposed only during pregnancy) were also affected, with altered metabolic machinery and body weight at 4 months postpartum, long after exposures had ended. The increased incidence of breast cancer in women that took DES during pregnancy also illustrates this point (596, 597). These studies suggest that even the adult endocrine system is not invariably capable of maintaining a so-called homeostatic state when exogenous chemicals affecting the endocrine system are present. Thus, although adult exposures to EDCs have been given some attention by bench scientists (29), more work of this kind is needed to better understand whether and how EDCs can have permanent organizational effects on adult animals.

At the beginning of this review, we justified the need to critically examine the low-dose literature because of recent epidemiological findings linking EDC exposures and diseases. Yet there is inherent difficulty in examining neonatal exposures to EDCs and their connection to diseases due to the length of time needed for these studies; thus, many studies of this type have examined high doses of pharmaceuticals (*i.e.* DES) or accidental exposures to industrial chemicals (*i.e.* dioxin) (66, 398, 399, 581, 597–601).

Only recently, with the availability of biomonitoring samples from large reference populations, have lower doses begun to receive widespread attention from epidemiologists. Many recent studies have examined adult exposures to EDCs and correlated exposures with disease statuses (see for example Refs. 15, 16, and 602–604). Human studies examining fetal/neonatal exposures to low-dose EDCs and early life effects have also begun to be studied (6, 333, 605–607), although studies linking these early life exposures to adult diseases are likely to be decades away. More than anything, these studies support our view that the effects of low-dose exposures should be considered when determining chemical safety.

3. Importance of endpoints being examined

Traditional toxicology testing, and in particular those studies performed for the purposes of risk assessment, typically adhere to guideline studies that have been approved by international committees of experts (608). The endpoints assessed in these guideline-compliant studies are centered around higher-order levels, including death, weight loss, mortality, and changes in organ weight, and a limited number of histopathological analyses (609, 610). When pregnant animals are included in toxicological assessments, the endpoints measured typically include the ability to maintain pregnancies, the number of offspring delivered, sex ratios of surviving pups, and measures regarding maternal weight gain and food/water intake (610).

Yet low-dose EDCs are rarely toxic to the point of killing adult animals or causing spontaneous abortions, and traditional tests such as the uterotrophic assay have been shown to be relatively insensitive (72, 577). It has been argued that this type of testing is insufficient for understanding the effects of EDCs (31, 70, 495, 611). Many EDC studies have instead focused on examining newly developed, highly sensitive endpoints that span multiple levels of biological organization, from gene expression to tissue organization to organ systems to the whole animal (612), which may not be rapidly lethal but which nonetheless have enormous importance for health, including mortality. Thus, for example, studies designed to examine the effects of chemicals on obesity no longer focus on body weight alone but also analyze gene expression; fat content in adipose cells and the process of adipogenesis; inflammation, innervation, and vascularization parameters in specific fat pads; conversion rates of white and brown adipose tissues; systemic hormone levels and response to glucose and insulin challenges; and food intake and energy expenditures, among others (314, 613–615). As our knowledge of EDCs and the endocrine system continue to grow, the most sensitive endpoints should be used to determine whether a chemical is disrupting the development of organisms (70).

In moving beyond traditional, well-characterized health-related endpoints like mortality and weight loss, an important question has been raised: how do we define endpoints as adverse? This is an important point, because it has been suggested that the creative endpoints examined in independent EDC studies are not validated and may not represent adverse effects (609). There is also debate over whether the mechanism (or mode) of action must be explained for each effect to determine whether a relevant pathway is present in humans (616, 617). Yet, when originally assessing the low-dose literature, the NTP expert panel chose to examine all effects of EDC exposure, regardless of whether the endpoint could be deemed adverse (2). From the perspective of developmental biology, any change in development should be seen as adverse, even if the change itself is not associated with a disease or dysfunction. Some of these developmental changes, in fact, may increase sensitivity or susceptibility to disease later on in life but will otherwise appear normal. Furthermore, studies of heavy metals have shown that small shifts in parameters like IQ may not have drastic effects on individuals but can have serious repercussions on the population level (618), and therefore changes in the variance/observable range of a phenotype should also be considered adverse (52).

4. Importance of study size

National Institutes of Health guidelines require that the number of vertebrate animals used in experiments be as small as possible to show statistically significant effects based on power analysis. Yet many traditional toxicology studies have used large numbers of animals to draw conclusions about chemical safety. When the endpoints being assessed have binary outcomes (*i.e.* animal has a tumor *vs.* animal does not have a tumor) and the incidence of the phenotype is not high, a large number of animals is required to reveal statistically significant effects. In contrast, many of the endpoints examined in the field of endocrine disruption are more complex and are not binary; thus, power analysis allows researchers to determine how many animals are needed to observe statistically significant (and biologically relevant) differences between control and exposed populations. For this reason, arbitrary numbers set as cutoffs for determining whether a study is acceptable or unacceptable for risk assessments are not appropriate. Instead, the number of animals required for a study to be complete is dependent on the effect size, precision/variance, minimal meaningful difference to be considered between populations, and the α-value set in statistical tests.

B. Regulatory science

For decades, regulatory agencies have tested, or approved testing, of chemicals by examining high doses and then extrapolating down from the NOAEL, NOEL, and LOAEL to determine safe levels for humans and/or wildlife. As discussed earlier, these extrapolations use safety factors that acknowledge differences between humans and animals, exposures of vulnerable populations, interspecies variability, and other uncertainty factors. These safety factors are informed guesses, not quantitatively based calculations. Using this traditional way of setting safe doses, the levels declared safe are never in fact tested. Doses in the range of human exposures are therefore also unlikely to be tested. This has generated the current state of science, where many chemicals of concern have never been examined at environmentally relevant low doses (see Table 4 for a small number of examples).

Assumptions used in chemical risk assessments to estimate a threshold dose below which daily exposure to a chemical is estimated to be safe are false for EDCs. First, experimental data provide evidence for the lack of a threshold for EDCs (619). More broadly, the data in this review demonstrate that the central assumption underlying the use of high doses to predict low-dose effects will lead to false estimates of safety. The use of only a few high doses is based on the assumption that all dose-response relationships are monotonic and therefore that it is appropriate to apply a log-linear extrapolation from high-dose testing to estimate a safe reference dose (Fig. 4). The Endocrine Society issued a position statement on EDCs (620) and urged the risk assessment community to use the expertise of their members to develop new approaches to chemical risk assessments for EDCs based on principles of endocrinology. Undertaking this mission will represent a true paradigm shift in regulatory toxicology (79). The Endocrine Society statement was then supported in March 2011 by a letter to *Science* from eight societies with relevant expertise representing over 40,000 scientists and medical professionals (621).

Studies conducted for the purposes of risk assessment are expected to include three doses: a dose that has no effects on traditional toxicological endpoints (the NOAEL), a higher dose with effects on traditional endpoints (the LOAEL), and an even higher dose that shows toxicity. Although reducing the number of animals used for these types of studies is an important goal, more than three doses are often needed for a true picture of a chemical's toxicity. The examination of a larger number of doses would allow for 1) the study of chemicals at the reference dose, *i.e.* the dose that is calculated to be safe; 2) examination of doses in the range of actual human exposures, which is likely to be below the reference dose; and 3) the ability to detect NMDRCs, particularly in the low-dose range. The impact of testing more doses on the numbers of animals required can be mitigated by use of power analysis, as suggested above. Because no amount of research will ever match the diversity and reality of actual human experience, there should be ongoing epidemiological study of potential adverse effects of EDCs even after safe levels are published, with periodic reevaluation of those safe levels.

One issue that has been raised by regulatory agencies is whether animal models are appropriate for understanding the effects of EDCs on humans. These arguments largely center around observed differences in hormone levels during different physiological periods in rodents and humans (57), and differences in the metabolic machinery and excretion of chemicals between species (622). To address the first issue, it should be noted that the FDA uses animals to test pharmaceuticals and other chemicals before any safety testing in humans because it is widely recognized that, although animals and humans do not have exactly the same physiologies, there is evolutionary conservation among vertebrates and specifically among mammals (62). Furthermore, animal studies proved to be highly predictive of the effects of DES on women, indicating that rodents are sufficiently similar to humans to reliably forecast affected endpoints in the endocrine system (64, 623). Thus, the default position must be that animal data are indicative of human effects until proven otherwise.

With regard to the second issue, BPA researchers in particular have examined species-specific differences in metabolism of this EDC. Interestingly, the pharmacokinetics of BPA in rodents, monkeys, and humans appear to be very similar (624), and regulatory agencies have subsequently concluded that rodents are appropriate models to assess the effects of this chemical (625, 626). Thus, researchers should select animal models that are sensitive to low doses of hormones and select appropriate species for the endpoints of interest. As the scope of our knowledge has broadened about how chemicals can alter the endocrine system, well beyond estrogens, androgens, and the thyroid, it is imperative that considerable thought be given to how to apply this for regulatory purposes.

C. Human health

As discussed several times throughout this review, there is now substantial evidence that low doses of EDCs have adverse effects on human health. Thus, although many epidemiological studies originally focused on occupationally exposed individuals and individuals affected by accidental exposures to high doses of environmental chemicals, these recent studies have suggested wide-ranging effects of EDCs on the general population.

Importantly, human exposures are examples of true mixtures; dozens if not hundreds of environmental chemicals are regularly detected in human tissues and fluids (91), yet very little is known about how these chemicals act in combination (627). Several studies indicate that EDCs can have additive or even synergistic effects (143, 323, 628–630), and thus these mixtures are likely to have unexpected and unpredictable effects on animals and humans. The study of mixtures is a growing and complex field that will require considerable attention in the years ahead as knowledge of EDCs in the laboratory setting are applied to human populations (631, 632).

How much will human health improve by testing chemicals at low, environmentally relevant doses and using the results to guide safety determinations? Current testing paradigms are missing important, sensitive endpoints; because they are often unable to detect NMDRCs, they cannot make appropriate predictions about what effects are occurring at low doses. At this time, it is not possible to quantify the total costs of low-dose exposures to EDCs. However, current epidemiology studies linking low-dose EDC exposures to a myriad of health problems, diseases, and disorders suggest that the costs of current low-dose exposures are likely to be substantial.

The weight of the available evidence suggests that EDCs affect a wide range of human health endpoints that manifest at different stages of life, from neonatal and infant periods to the aging adult. As the American population ages, healthcare costs continue to rise, and there are societal costs as well, with decreased quality of life concerns, decreases in work productivity due to illness or the need for workers to care for affected family members, and the psychological stresses of dealing with some outcomes like infertility. Thus, it is logical to conclude that low-dose testing, followed by regulatory action to minimize or eliminate human exposures to EDCs, could significantly benefit human health. This proposal effectively calls for greatly expanded research to give human communities feedback about themselves. It emanates from a view that human society benefits greatly from the many chemical compounds it uses but that extensive epidemiological surveillance and other focused research designs are needed to assure that the balance of risk/benefit from those chemicals is acceptable.

How much would human health benefit by a reduction in the use of EDCs? For some chemicals, minor changes in consumer habits or industrial practices can have drastic effects on exposures (633–636). Other chemicals like DDT that have been regulated in the United States for decades continue to be detected in human and environmental samples; the persistent nature of many of these agents suggests they may impact human health for decades to come. Even less-persistent chemicals like BPA are likely to remain in our environment long after a ban is enacted because of the large amounts of plastic waste leaching BPA (and other estrogenic compounds) from landfills into water sources (637) and its presence on thermal receipt paper and from there into recycled paper (638–640). Yet, despite these challenges, reducing human exposure to EDCs should be a priority, and one way to address that priority is to decrease the production and use of these chemicals. The Endocrine Society has called for such a reduction and the use of the precautionary principle, *i.e.* action in the presence of concerning information but in the absence of certainty to eliminate or cut the use of questionable chemicals even when cause-effect relationships are not yet established (620).

D. Wildlife

Much of the recent focus on EDCs has been on the impact of these chemicals on human health. Yet the earliest studies of EDCs that focused on the impact of these chemicals on wildlife should not be forgotten. Rachel Carson's work on DDT and other pesticides provided some of the earliest warning signs that there were unintended consequences of chemical use. Carson's work was ahead of its time; she understood that exceedingly small doses of these chemicals produced adverse effects, that the timing of exposures was critical, and that chemical mixtures produced compounded effects (641). Now, decades after some of the most dangerous EDCs have been regulated, they continue to be measured in environmental samples as well as the bodies of wildlife animals.

Furthermore, it should be pointed out that humans, like wildlife, are not insulated from the environment, and effects in wildlife, including nonmammalian species, are indicative of and mirror effects in humans. For example, BPA has estrogen-like effects in fish (642–644), amphibians (645, 646), and reptiles (647, 648). A recent review showed that demasculinizing and feminizing effects of atrazine have been demonstrated in fish, amphibians, reptiles, birds, and mammals, *i.e.* every vertebrate class examined (326); and in fact, the first report to suggest that atrazine induced aromatase was conducted in reptiles (649). Similarly, perchlorate affects fish (650–653), amphibians (654–658), and birds (659–661) via mechanisms consistent with those described for humans, and some of the earliest reports on perchlorate's effects on thyroid function were conducted in amphibians (661, 662). Finally, ecological studies of dioxin and dioxin-like chemicals reveal effects on a range of exposed wildlife including birds (663, 664), fish (665, 666), and invertebrates (667). Although these studies have highlighted some of the species-specific effects of dioxin (389), and orders of magnitude differences in toxic equivalency factors between species (668), they also indicate the conservation of mechanisms for the effects of dioxin on a range of biological endpoints in wildlife, laboratory animals, and humans (384). In fact, in many cases, nonmammalian species are much more sensitive to EDC effects, and wildlife species serve as sentinels for environmental and public health (669–673). Thus, the effects of these chemicals on wildlife populations are likely to continue; for this reason, the low-dose effects of these chemicals are particularly worth understanding (674, 675).

V. Summary

In conclusion, we have provided hundreds of examples that clearly show that NMDRCs and low-dose effects are common in studies of hormones and EDCs. We have examined each of these issues separately and provided mechanistic explanations and examples of both. These topics are related, but they must be examined individually to be understood. The concept of nonmonotonicity is an essential one for the field of environmental health science because when NMDRCs occur, the effects of low doses cannot be predicted by the effects observed at high doses. In addition, the finding that chemicals have adverse effects on animals and humans in the range of environmental exposures clearly indicates that low doses cannot be ignored.

In closing, we encourage scientists and journal editors to publish data demonstrating NMDRCs and low-dose effects, even if the exact mechanism of action has not yet been elucidated. This is important because the study of EDC is a growing specialty that crosses many scientific fields, and scientists that work on or regulate EDCs should appreciate and acknowledge the existence of NMDRCs and low-dose effects and have access to this important information. We further recommend greatly expanded and generalized safety testing and surveillance to detect potential adverse effects of this broad class of chemicals. Before new chemicals are developed, a wider range of doses, extending into the low-dose range, should be fully tested. And finally, we envision that the concepts and empirical results we have presented in this paper will lead to many more collaborations among research scientists in academic and government laboratories across the globe, that more and more sophisticated study designs will emerge, that what we have produced herein will facilitate those making regulatory decisions, that actions taken in light of this information will begin to abate the use of EDCs, and ultimately that health impacts in people and in wildlife will be averted.

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Air

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Report to Congress on Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas

HYDROGEN SULFIDE REPORT TO CONGRESS -- EXECUTIVE SUMMARY

Under section 112(n)(5) of the Clean Air Act (CAA), as amended, Congress required the Administrator of the United States Environmental Protection Agency (EPA) to carry out a study to assess the hazards to public health and the environment resulting from the emission of hydrogen sulfide (H_2S) associated with the extraction of oil and natural gas. The assessment must include a review of existing State and industry control standards, techniques, and enforcement. This report, developed in fulfillment of section 112 (n)(5), evaluates the hazards to the public and the environment posed by these emissions.

This study was added to the CAA by the Committee on Environment and Public Works, chaired by the late Senator Quentin N. Burdick of North Dakota, because of concern about the health and environmental hazards associated with H_2S emissions from oil and gas wells. Witnesses testified before Congress that these emissions resulted in deterioration of air quality, death and injury to livestock, and evacuation and hospitalization of residents located near the release point of such emissions.

Congress considered listing H_2S as a hazardous air pollutant (HAP) under section 112(b) of the CAA, which regulates industrial sources of routine emissions of HAPs. On the basis of information contained in accident records, it was determined that H_2S is a concern from an accidental release standpoint and it would be listed under the accidental release provisions in section 112(r) of the Act, and not under section 112(b). Substances regulated under 112(r) are known or may be anticipated to cause death, injury, or serious adverse effects to human health or the environment upon accidental release.

Hydrogen sulfide is produced in nature primarily through the decomposition of organic material by bacteria. It develops in stagnant water that is low in oxygen content, such as bogs, swamps, and polluted water. The gas also occurs as a natural constituent of natural gas, petroleum, sulfur deposits, volcanic gases, and sulfur springs. Natural sources constitute approximately 90 percent of the atmospheric burden of H_2S. Ambient air concentrations of H_2S due to natural sources are estimated to be between 0.11 and 0.33 ppb (0.15 and 0.46 $\mu g/m^3$).

H_2S is a colorless gas with an offensive odor characteristic of rotten eggs. H_2S is flammable and highly corrosive to metals. It is toxic and care should be exercised in its presence. There have been several incidences in the United States of deaths of workers exposed to H_2S gases. Other symptoms of exposure include irritation, breathing disorders, nausea, vomiting, diarrhea, giddiness, headaches, dizziness, confusion, rapid heart rate, sweating, weakness, and profuse salivation. Levels above 1.5×10^5 ppb are considered life threatening. Few studies exist measuring effects of natural or accidental exposure of wildlife to H_2S; however, wildlife deaths have been reported in connection with blowouts (a sudden expulsion of gas or oil well fluids with great velocity).

Natural gas and oil formations may be composed of many gases. The largest volume and most beneficial gases in this composition are generally the light hydrocarbons (methane, ethane, propane, and butane). H_2S is the most common impurity in hydrocarbon gases. If an oil and gas formation contains H_2S, it is said to be "sour." Although a sour well's oil and gas can be sweetened by removing the H_2S after extraction, the well is always considered sour once H_2S is present.

Certain areas of the United States are especially prone to contain H_2S in oil and gas reservoirs at varying depths underground. Vulnerability zones have been characterized as 14 major H_2S prone areas found in 20 States. Texas has four discrete H_2S prone areas. Concentrations as high as 42 percent H_2S (by volume) have been found in gas from central Wyoming.

In the oil and gas industry, H_2S may be emitted or released during exploration, development, extraction, crude treatment and storage, transportation (e.g., pipeline), and refining. This report focuses on potential hazards of routine emissions and accidental releases of H_2S from the extraction and storage of crude oil and natural gas at well sites. Potential sources of emissions include flares/vapor incinerators, heater-treaters (an oil/water/gas separation device), storage tanks, equipment (valves, flanges, etc.), and both active and abandoned wells.

When H_2S is released to the air from an oil or gas well, several factors determine its possible effects on surrounding residents and the environment. Accidental releases of sour gas, such as from a well blowout or pipe rupture, are usually at high pressure and will entrain surrounding air. This causes significant, immediate dilution of the H_2S and other components of the gas, thereby reducing the potential magnitude of the consequences of the release. Factors such as chemical composition of the expelled gas, release rate, release orientation, topography and meteorological conditions also determine the effects of such a release.

Human fatalities from H_2S exposure from oil wells in the United States have virtually all been work-related. Significant public impacts are rare although evacuations have been initiated in response to accidental releases and at least one case of loss of consciousness has been reported as a result of exposure.

Eighteen states have developed ambient air quality guidelines for H_2S. Most, however, do not collect continuous data but rather only monitor for H_2S when a complaint is made. These guidelines range from 160 ppb per 24-hr averaging time to 14 ppb per 24-hr averaging time. Little data exist to determine actual levels of H_2S near oil and gas extraction sites. North Dakota was the only State found to have a continuous record of H_2S atmospheric levels at several sites. Exceedences of the North Dakota air quality standard have been minimal in recent years at these monitoring locations. No specific H_2S environmental (i.e., ecological) protection standards were found to exist. Some States require notification of the regulatory authority upon accidental release of H_2S from oil and gas wells but few maintain an inventory of such incidences. Reporting of routine emissions (emissions of small quantities from equipment, pipelines, flares, and storage tanks) was not required by the States reviewed in this report.

H_2S is regulated under a number of United States statutes. It is listed as a hazardous substance under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA). It is listed under the Emergency Planning and Community Right-to-Know Act (EPCRA) for emergency planning and preparedness, community right-to-know reporting, and toxic chemical release reporting. The Occupational Safety and Health Administration (OSHA) has established General Industry Standards that list worker exposure concentration limits, and Respirator Standards. The National Institute for Occupational Safety and Health (NIOSH) has produced a criteria document containing recommendations for safe worker exposure levels and work practices. The United States EPA has the potential for regulation of new oil and gas well sources through the Prevention of Significant Deterioration (PSD) program and, as mentioned previously, H_2S is listed under the CAA section 112(r) accidental release provisions.

Other standards for worker and public protection from H_2S emissions come from the Bureau of Land Management, Minerals Management Service, and the American Conference of Governmental Industrial Hygienists.

The oil and gas production industry has guidelines for safe practices regarding H_2S. The American Petroleum Institute, an industry-wide technical organization, has published six documents regarding H_2S in the industry. They pertain to safety practices for drilling, operation, and equipment.

Findings and Recommendations

As a result of this study, EPA finds that the potential for human and environmental exposures from routine emissions of H_2S from oil and gas wells exists, but insufficient evidence exists to suggest that these exposures present any significant threat. On the other hand, an accidental release of H_2S from an oil or gas well could have severe consequences because of its toxicity and its potential to travel significant distances downwind under certain circumstances. The likelihood (and thus the risk) of an accidental release of H_2S or any other hazardous substance, can be greatly reduced if facility owners/operators exercise the general duty and responsibility to design and operate safe facilities and if they comply with existing industry standards and practices, existing regulations, and future guidance and regulations. Such actions should result in: (1) the safe management of H_2S and other hazardous substances with an emphasis on accident prevention; (2) the preparedness to properly and quickly respond to chemical emergencies and to provide specialized medical treatment if necessary; and (3) community understanding of the risks involved. Industry should ensure that H_2S is safely handled and that accidental releases are prevented; that any releases that do occur are quickly discovered, controlled, and mitigated; and that workers and the community are informed and prepared to properly respond to a H_2S emergency.

From the limited data available, there appears to be no evidence that a significant threat to public health or the environment exists from routine emissions from sour oil and gas wells. States and industry are encouraged to evaluate existing design, construction, and operation principles within the framework of process safety management. EPA recommends no further legislation pertaining to routine H_2S emissions or accidental releases from oil and gas wells at this time. However, the Agency does recommend that the owner/operators of oil and gas extraction conduct drills and exercises with workers, the community, first responders, and others to test mitigation, response, and medical treatment for a simulated H_2S accident. Sour oil and gas extraction facilities should be able to rapidly detect, mitigate, and respond to accidental releases in order to minimize the consequences. The Agency will continue to investigate the need for additional rulemaking under the accidental release prevention provisions of the Clean Air Act.

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CHAPTER I
INTRODUCTION

STATUTORY REQUIREMENTS

Section 112(n)(5) of the Clean Air Act (CAA or Act), as amended in 1990, requires the Environmental Protection Agency (EPA) "to assess the hazards to the public and the environment resulting from the emissions of hydrogen sulfide (H_2S) associated with the extraction of oil and natural gas resources." This assessment must reflect consultation with the States and shall include a review of State and industry control standards, techniques, and enforcement. To avoid duplication of work by other EPA offices, the assessment must build upon a report from the Office of Solid Waste conducted under Section 8002(m) of the Solid Waste Disposal Act. The Section 8002(m) study is a three-volume report to Congress entitled *Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy* (1987).

The EPA Administrator is required by the Act to report to Congress with the findings of the assessment along with any recommendations. Moreover, under Section 112(n)(5) (or 42 U.S.C.7412(n)5), the Administrator "shall, as appropriate, develop and implement a control strategy for emissions of hydrogen sulfide to protect human health and the environment."

This study was added to the Act by the Committee on Environment and Public Works chaired by the late Senator Quentin N. Burdick of North Dakota. The study was included in the Act because of concern about the health and environmental hazards associated with H_2S emissions from oil and gas wells. In 1987, Congress received testimony in which witnesses urged that H_2S should be listed as a hazardous air pollutant under the provisions of Section 112 of the Clean Air Act. The witnesses testified that lack of emission controls resulted in significant deterioration of air quality. There was also testimony that H_2S releases from oil and gas facilities caused death and injury to livestock and required the evacuation and hospitalization of residents from affected areas.

Congress considered listing H_2S as a hazardous air pollutant (HAP) under Section 112(b), which regulates industrial sources for routine emissions of HAPs. On the basis of information contained in accident records, it was determined that H_2S is a concern from an accidental release standpoint and should be listed under the accidental release provisions in Section 112(r) of the Act. The substances regulated under Section 112(r) are known or may be anticipated to cause death, injury, or serious adverse effects to human health or the environment from accidental releases. Under the provisions of Section 112(r) of the Act, the EPA must develop a list of at least 100 substances that pose the greatest risk from accidental releases. The Act listed 16 chemicals, including H_2S, which must be included in the Section 112(r) list.

A clerical error led to the inadvertent addition of H_2S to the Section 112(b) list of HAPs. However, a Joint Resolution to remove H_2S from the Section 112(b) list was passed by the Senate on August 1, 1991, and the House of Representatives on November 25, 1991. The Joint Resolution was approved by the President on December 4, 1991. It should be emphasized that the purpose of this report is not to examine whether or not H_2S should be included in the Section 112(b) list.

SCOPE OF REPORT

The scope of this report is determined by the Congressional directive found in Section 112(n)(5), which is quoted in its entirety in Exhibit 1. For clarity, the Agency has designed the report to respond to specific items in the directive within separate chapters or sections of chapters. It is important to note that although all issues relevant to this study have been weighed in arriving at the conclusions and recommendations of this report, no single issue has a determining influence on the conclusions and recommendations.

The directive in Section 112(n)(5) is expanded upon in the paragraphs below. Detailed methodologies used to analyze and respond to the directive can be found later in this report and in the supporting documentation and appendices. The principal components of the Congressional mandate are:

1. Review existing State and industry control standards, techniques, and enforcement programs.

Currently, there are no Federal ambient air quality standards for H_2S. Most oil- and gas-producing States have their own regulations and enforcement programs. Some States, such as some hosting major producers, have large H_2S programs in place. However, the risk may exist in States that do not have large programs simply because of the lack of State regulatory overview. Although Occupational Safety and Health Administration (OSHA) standards exist that are applicable to oil and gas production, there are no industry-specific standards. However, the industry has developed recommended practices and technologies to reduce the potential for H_2S emissions.

Current State regulations regarding H_2S emissions from the extraction of oil and gas are summarized in this report, with emphasis on four oil-producing States—California, Michigan, Oklahoma, and Texas. Industry safety procedures as well as regulations promulgated and proposed by OSHA and other Federal regulatory programs are reviewed.

2. Assess the hazards to public health and the environment resulting from the emission of H_2S associated with extraction of oil and natural gas resources.

Hydrogen sulfide is a colorless gas almost as toxic as hydrogen cyanide and 5 to 6 times more toxic than carbon monoxide. The principal threat of H_2S gas to human life is poisoning by inhalation (Dosch and Hodgson, 1986). Over the years, there have been

112(n)(5) **Hydrogen Sulfide.**– The Administrator is directed to assess the hazards to public health and the environment resulting from the emission of hydrogen sulfide associated with the extraction of oil and natural gas resources. To the extent practicable, the assessment shall build upon and not duplicate work conducted for an assessment pursuant to section 8002(m) of the Solid Waste Disposal Act and shall reflect consultation with the States. The assessment shall include a review of existing State and industry control standards, techniques, and enforcement. The Administrator shall report to the Congress within 24 months after the date of enactment of the Clean Air Act Amendments of 1990 with the findings of such assessment, together with any recommendations, and shall, as appropriate, develop and implement a control strategy for emissions of hydrogen sulfide to protect human health and the environment, based on the findings of such assessment, using authorities under this Act including sections 111 and this section.

Exhibit 1. 1990 Clean Air Act Amendments: Mandate for a Report to Congress on H_2S Emissions Associated with Oil and Gas Extraction.

incidents involving exposure to H_2S resulting from accidental releases from oil and gas extraction facilities that have caused death or injury to humans or animals (Layton, D.W., et al; Texas Oil and Gas Pipeline Corporation).

Oil and gas extraction, as defined in this study (see Appendix A), includes only the activities involved in removing oil and/or gas from an established (developed) well. This report includes not only a review of oil and gas extraction, but also other associated components of oil and gas extraction such as piping to a separator, separation, and storage. <u>However, in following the Congressional mandate to address extraction, this report does not cover activities primarily associated with exploration or well development, nor does it cover sources such as gas processing plants</u>. It is noteworthy that these plants are potential sources of H_2S releases since one of their functions is to remove impurities such as produced water, H_2S and/or carbon dioxide. Personnel at these plants are trained in H_2S safety. However, this operation falls outside the definition of extraction.

In addition to assessing the sources of H_2S emissions in the extraction industry, this report discusses related control technologies as well as the health and environmental effects associated with exposure to accidental H_2S releases and routine H_2S emissions during extraction and closely associated production activities. When possible, monitored ambient air concentrations of H_2S and cases of death or injury to humans, wildlife, and/or livestock from exposure to H_2S releases and emissions are documented.

The report culminates with a hazard assessment of H_2S routine emissions and accidental releases from oil and gas extraction activities based on information obtained in the efforts described in the previous paragraphs. Past and potential hazards from both routine emissions and accidental releases are identified, the degree of hazard is assessed, and potentially exposed human and ecological populations are identified.

3. **Recommend and, as appropriate, develop and implement a control strategy for H_2S emissions to protect human health and the environment, based on the findings of such assessment, using authorities under this act including sections 111 and 112.**

As stated in a 1987 Senate report on the Clean Air Act Amendments, "Although many State [H_2S regulatory] programs are implemented conscientiously, in some instances concerns have been raised that some oil- and gas-producing States may not be enforcing their regulatory programs sufficiently or may have deficient regulatory programs. The purpose of this subsection is to assess the effectiveness and the level of enforcement of various hydrogen sulfide control programs. The assessment should assure more uniform application of control technology, standards and enforcement. The Administrator should examine in particular means of preventing accidental releases of hydrogen sulfide at remote facilities" (U.S. Senate, 1987). [EPA identifies and reviews current State and Federal regulatory programs and industry-recommended procedures to reduce routine emissions and accidental releases. However, the ability to assess the effectiveness of these programs is limited by the lack of available emissions-monitoring data and the limited information available on accidental release incidents.]

In this report, EPA makes recommendations regarding the release of H_2S from oil and gas extraction activities. The recommendations presented in this report do not constitute a regulatory determination. The Agency is, in several important areas, presenting optional approaches involving further research and consultation with the States and other affected parties.

ORGANIZATION OF REPORT

This report addresses two forms of H_2S losses to the atmosphere: routine emissions and accidental releases. (These terms are defined in the Glossary and examples are provided in Chapter II.)

Chapter II provides an overview of H_2S formation in oil and natural gas deposits and its presence in numerous industries. Potential sources of routine emissions and accidental releases from the oil and natural gas extraction industry are identified along with their causes. Chapter III is a hazard assessment of H_2S losses from oil and gas wells. It contains information on the nature of hydrogen sulfide's hazardous properties; exposure and consequence analyses for routine emissions and accidental releases; protective guidelines, prevention, mitigation, and emergency response procedures; and a characterization of land use around wells and of affected human populations and environmental settings. Chapter IV reviews and evaluates current State, Federal, and industry-recommended procedures related to H_2S in the oil and natural gas extraction industry. At the end of both Chapters III and IV are lists of findings to provide the reader with a condensed summary of key information identified during the development of this report. Chapter V completes the report with EPA recommendations regarding routine emissions and accidental releases of H_2S from oil and gas extraction operations.

This report contains a glossary of terms commonly used, and three appendices providing:

- background information on oil and gas production;
- subjects of State H_2S regulations and guidelines; and
- atmospheric dispersion calculations for accidental H_2S releases.

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CHAPTER II
HYDROGEN SULFIDE FORMATION AND ITS ROLE IN OIL AND GAS PRODUCTION

OVERVIEW

Petroleum oil and natural gas originate in organic-rich sedimentary source rocks composed of decayed marine algae and bacteria and terrestrial plants. In rock formations, temperature increases with depth. The organic matter (kerogen) in sedimentary rock is thermally converted to oil and gas at a specific temperature and migrates from the source rock formation into a reservoir, or trap, formed by less porous cap rock, usually shale. Once the well has been drilled into the reservoir, the oil and gas flow through the interconnected pore spaces to the well.

Natural gas may be composed of many gases. Only a few of these gases are typically found in large concentrations. The largest volume and most beneficial gases in natural gas are the light hydrocarbons (methane, ethane, propane and butane). Other gases that may occur in large concentrations are carbon dioxide, nitrogen, and hydrogen sulfide. H_2S is the most common impurity in hydrocarbon gases.

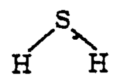
H_2S is generated under reducing conditions from high-sulfur kerogens or oils and is most commonly formed in sedimentary rock formations such as limestone (calcite or calcium carbonate). H_2S can also be generated from hydrocarbon reactions with sulfates in carbonate rock formations containing anhydrites. Oil and gas formations that do not contain H_2S are called "sweet." Oil and gas formations that contain H_2S are described as "sour." Sour gas is defined by the U.S. EPA as natural gas with an H_2S concentration greater than 0.25 grains per 100 cubic feet (GRI, 1990). Others have defined sour gas as having H_2S concentrations greater than 1.0 grain per 100 cubic feet (Amyx, Bass, and Whiting, 1960) or greater than 2 percent (Curtis and Showalter, 1989). The American Petroleum Institute recommends special practices (described in Chapter IV) for sour gas when the natural gas's total pressure is greater than or equal to 65 psia (448 kPa) and the partial pressure of H_2S in the gas is greater than 0.05 psia (0.34 kPa) (API, 1987). It is not known how many sour wells exist in the United States. Sweet oil wells can become sour due to the introduction of sulfur-reducing bacteria during enhanced oil recovery injection. Once an oil or gas field becomes sour, it cannot be made sweet again. However, after extraction from the well, the oil and gas can be sweetened by processing to remove H_2S, and this is a common procedure.

In relatively low concentrations, H_2S has a strong rotten-egg odor (Landes, 1953). However, the sense of smell rapidly becomes fatigued and cannot be relied on to warn of the continuous presence of H_2S. In fact, high concentrations of H_2S may cause a loss of smell. Concentrations of H_2S in crude oil vary greatly. In California alone, the Shiells Canyon oil field measures only 6×10^4 ppb of H_2S, while the Santa Maria Valley oil field has reported H_2S concentrations of 2.7×10^7 ppb (27 percent by weight) (Dosch and Hodgson, 1986).

Table II-1. Physical/Chemical Properties of H_2S

Chemical Formula: H_2S

Molecular Structure:



Molecular Weight: 34.08

Boiling Point: -60.33 °C (-76.59 °F)

Specific Gravity ($H_2O=1$): 0.916 at -60 °C (-76 °F) (Liquid) 1.54 g/L vapor at 0 °C (32 °F)

Vapor Pressure: 20 atmospheres at 25.5 °C (77.9 °F)

Melting Point: -85.49 °C (-121.9 °F)

Vapor Density (AIR=1): 1.19

Solubility in Water: 1 gram dissolves in 242 mL at 20 °C (68 °F)

Flammable Limits: Lower Explosive Limit – (4.3×10^7 ppb)
Upper Explosive Limit – (45.5×10^8 ppb)

Odor Threshold: 20 ppb[a]

Olfactory Fatigue Level: 1×10^5 ppb[a]

Conditions or Materials to Avoid: Avoid physical damage to containers; sources of ignition; and storage near nitric acid, strong oxidizing materials, and corrosive liquids or gases (NFPA, 1978). Hydrogen sulfide is incompatible with many materials, including strong oxidizers, metals (NIOSH/OSHA, 1978, p. 112), strong nitric acid, bromine pentafluoride, chlorine trifluoride, nitrogen triiodide, nitrogen trichloride, oxygen difluoride, and phenyl diazonium chloride (NFPA, 1978).

Hazardous Decomposition or Byproducts: When heated, it emits highly toxic fumes of oxides of sulfur (Sax, 1984, p. 1552)

Source: U.S. EPA, 1993.
[a]NIOSH, 1977.

Hydrogen sulfide is also called hydrosulfuric acid, sulfurated hydrogen, sulfur hydride, rotten-egg gas, swamp gas, and stink damp. Table II-1 lists some of the chemical and physical properties of H_2S. It is colorless, has a very low odor threshold, and being more dense than air, it tends to settle to the ground when released to the atmosphere as a pure gas (NIOSH, 1977). H_2S oxidizes to form sulfur dioxide (SO_2).

Exposure to H_2S is one potential health and environmental concern associated with extraction and related operations. H_2S is found in Paleozoic carbonates in the Rockies, Mid-Continent, Permian Basin, and Michigan and Illinois Basins (GRI, 1990). Figure II-1 shows the areas of naturally occurring H_2S. The Gas Research Institute reported in 1990 that H_2S can often occur in association with carbon dioxide (CO_2) within the deep portions of a basin and can comprise more than 30 percent of the composition.

Among the natural gas deposits in the United States, large deposits in central and north-central Wyoming, in western Texas, in southeastern New Mexico, and in Arkansas were singled out as rich in H_2S. The Health Effects Research Laboratory (HERL) also reported that H_2S concentrations as high as 42 percent may be present in gas from central Wyoming. According to the *Wyoming State Review* (1991), released by the Interstate Oil and Gas Compact Commission (IOGCC), gas reserves in Wyoming were estimated to be approximately 11 trillion cubic feet. The IOGCC also reported that the reserves of liquid hydrocarbons found in western Wyoming are approximately 5 percent H_2S. Fifty percent of the oil produced in Wyoming in 1989 was reported to be sour.

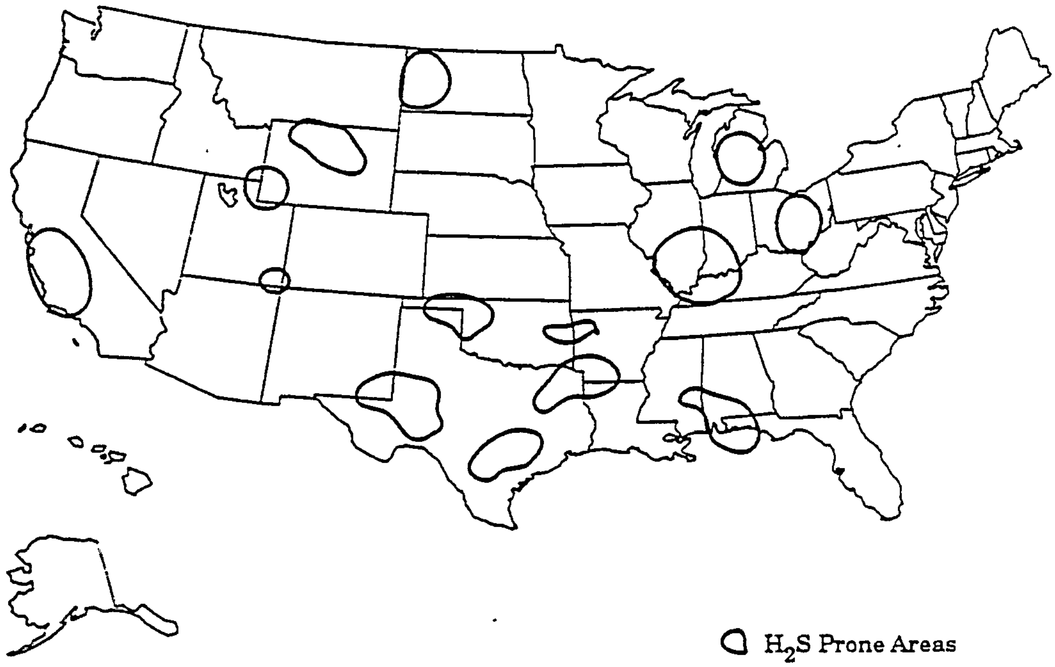
HYDROGEN SULFIDE IN INDUSTRY

Hydrogen sulfide has been cited as a potential hazard for approximately 125,000 employees in 73 industries (U.S. EPA, 1993). Industries with a potential exposure are listed in Table II-2. The health effects of H_2S were recognized in the petroleum industry more than 50 years ago with the discovery of large deposits of high-sulfur oil in the United States (Davenport, 1945). In the oil and gas industry, H_2S may be emitted or released during exploration, development, extraction, crude treatment and storage, transportation (e.g., pipeline transmission), and refining. This report focuses on potential hazards of H_2S routine emissions and accidental releases from the extraction and storage of crude oil and natural gas.

POTENTIAL H_2S EMISSION SOURCES IN THE OIL AND NATURAL GAS EXTRACTION INDUSTRY

Appendix A provides a general overview of the oil and gas extraction industry. Both the exploration/development and extraction sectors of the industry are described along with production data for recent years.

Hydrogen sulfide (H_2S) complicates oil and gas extraction operations because of its toxic effects and its corrosive properties. H_2S exists as a gas at atmospheric pressure, but it



Source: Gas Research Institute. 1990.

Figure II-1. Major H_2S prone areas.

Table II-2. Occupations with Potential H_2S Exposure

Animal fat and oil processors
Animal manure removers
Artificial-flavor makers
Asphalt storage workers
Barium carbonate makers
Barium salt makers
Blast furnace workers
Brewery workers
Bromide-brine workers
Cable splicers
Caisson workers
Carbon disulfide makers
Cellophane makers
Chemical laboratory workers, teachers, students
Cistern cleaners
Citrus root fumigators
Coal gasification workers
Coke oven workers
Copper-ore sulfidizers
Depilatory makers
Dyemakers
Excavators
Felt makers
Fermentation process workers
Fertilizer makers
Fishing and fish-processing workers
Fur dressers
Geothermal-power drilling and production workers
Gluemakers
Gold-ore workers
Heavy-metal precipitators
Heavy-water manufacturers
Hydrochloric acid purifiers
Hydrogen sulfide production and sales workers
Landfill workers
Lead ore sulfidizers
Lead removers
Lithographers
Lithopone makers
Livestock farmers
Manhole and trench workers
Metallurgists
Miners
Natural gas production and processing workers
Painters using polysulfide caulking compounds
Papermakers
Petroleum production and refinery workers
Phosphate purifiers
Photoengravers
Pipeline maintenance workers
Pyrite burners
Rayon makers
Refrigerant makers
Rubber and plastics processors
Septic tank cleaners
Sewage treatment plant workers
Sewer workers
Sheepdippers
Silk makers
Slaughterhouse workers
Smelting workers
Soapmakers
Sugar beet and cane processors
Sulfur spa workers
Sulfur products processors
Synthetic-fiber makers
Tank gagers
Tannery workers
Textiles printers
Thiophene makers
Tunnel workers
Well diggers and cleaners
Wool pullers

Source: NIOSH, 1977.

is soluble in oil and water. As a result of this solubility, H_2S can enter the environment by a variety of pathways. It can enter the atmosphere as a result of releases of gas containing H_2S or as a result of venting tanks or vessels which contain or have contained oil or water with significant concentrations of H_2S. Waters in the general environment can become contaminated with H_2S by contact with either gaseous plumes or waters that contain H_2S.

The potential sources of H_2S emissions associated with oil and gas extraction are summarized in Table II-3.

Routine emission sources may include—

- inefficient air emission control devices
- tank venting due to diurnal temperature changes;
- volatilization;
- generation by sulfur-reducing bacteria in oil deposits; and
- migration through poorly plugged wells.

Potential accidental release sources include —

- equipment failures, e.g., valves, flanges;
- piping ruptures due to corrosion, embrittlement, or stress; and
- venting due to unanticipated pressure changes.

Background information on these potential sources is provided in Appendix A.

The crude oil and natural gas industries use a large number of similar yet distinct industrial processes that together serve a common purpose: to remove hydrocarbons from subterranean deposits of oil and gas and to produce marketable products for industrial, commercial, and residential use. Figure II-2 shows the basic components of a typical oil and gas production operation. From the wellhead, the oil/gas mixture is piped to an oil/gas separator. Oil/water emulsions and mixtures are then transferred to a heater-treater, which separates the oil from the water. The treated crude oil is next piped to storage tanks, and the produced water is piped to a holding tank prior to further treatment and/or disposal. An emergency pit (a wastewater basin) is also provided. Each of these operations, as well as other equipment found at a well site, may be a source of H_2S in sour oil and gas operations.

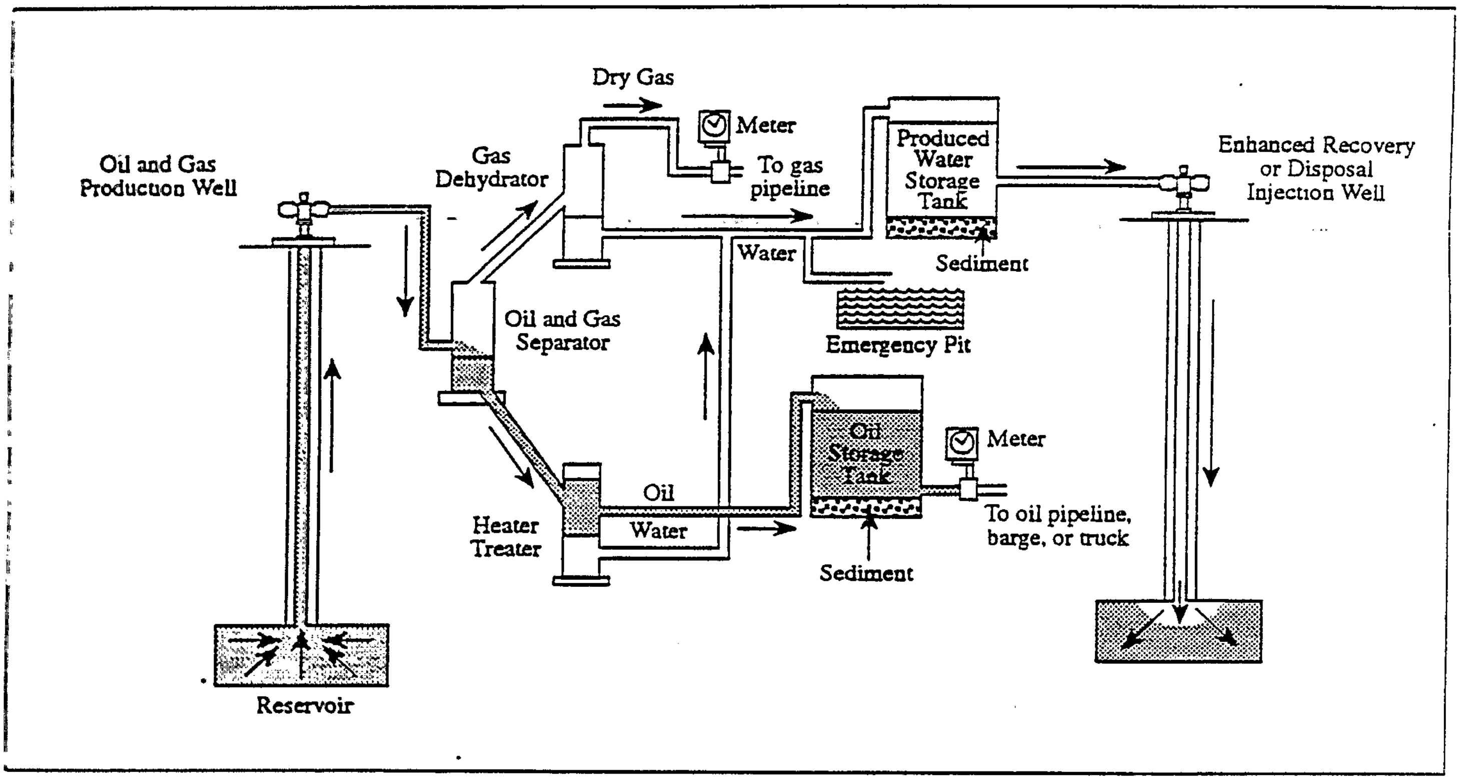
Oil and Gas Production Operations

Crude Oil

In the crude oil production process, releases or emissions of H_2S to the environment may occur from a variety of sources, including wellheads, piping, flares, separation devices, storage vessels, and pumps.

Table II-3. Examples of Potential Routine H_2S Emission Sources and Accidental H_2S Release Sources from Sour Oil and Gas Extraction

Source	Mechanism	Cause
Flares/vapor incinerators	Incomplete combustion	Design; lack of maintenance
Heater-treaters	Pressure change, high pressure	Pressure above design specifications
Crude oil storage tanks	Diurnal temperature change; filling operations; volatilization	Lack of controls; design
Water storage vessels	Volatilization; sulfur-reducing bacteria	Lack of controls; design
Equipment (valves, flanges, etc.) Oil/gas separator	Corrosion and embrittlement	Reaction of water with metal and H_2S; lack of maintenance; poor materials
Well plugging	Migration from well bore to atmosphere	Improper plugging



Source: U.S. EPA. 1987.

Figure II-2. Typical extraction operation showing separation of oil, gas, and water.

Flares are connected to points in the system where gas might be directed in case of an operating problem. Subject to regulatory approval, flares may also burn gases that cannot be sold. The gases are vented up a tall vertical pipe and then ignited at the top of the pipe, releasing heat and combustion products. Flares are connected to production vessel pressure-relief valves, rupture disks, and tank vents, among other places. Few data are available on the efficiency of flares used in a crude oil production setting; however, the operating efficiency of a common flare, regardless of industry application, is about 95 to 99 percent (personal communication, Donelson, Texaco, 12/9/92). The combustion product of H_2S is sulfur dioxide (SO_2). Incomplete combustion from flares is one possible source of H_2S emissions, and actual pollutant emissions vary depending on the combustion efficiency of the flare.

Devices, such as heater-treaters, break down water/oil emulsions or mixtures. These devices operate under pressure and do not normally emit H_2S. However, H_2S may be released in accidental situations when the vessel becomes subjected to pressures above design specifications. The pressure relief valve or a rupture disk will open in a high-pressure situation, and the gas will be sent through these openings via pipeline to a flare (personal communication, Donelson, Texaco, 12/9/92).

H_2S can potentially be emitted by two processes from vessels used to store water produced during extraction:

- Dissolved H_2S may be contained in the produced water and brought up from the reservoir. Pressure reductions from subsurface to surface change the solubility of H_2S in water and can release some H_2S from solution.
- H_2S may be produced by the action of sulfate-reducing bacteria in some aqueous and oil media. Biocides are used to kill these bacteria and eliminate H_2S formation.

Tanks storing crude oil are another potential source of H_2S emissions. H_2S can be discharged to the atmosphere from a storage tank as a result of diurnal temperature change, filling operations, and volatilization. The process of filling oil-transport vessels is another potential source of H_2S emissions. As the crude oil is loaded, gases containing the pollutant are displaced to the atmosphere. If the gas amounts do not warrant repressuring into the gas sales line, a flare may operate to burn the gas given off (personal communication, Donelson, Texaco, 12/9/92). There have been several accidents involving tanks that have H_2S in them. This is typically a worker safety issue.

Pumps that move the oil during the extraction process can leak oil at the seals between the moving shaft and the stationary casing, causing a possible release of H_2S.

Natural Gas

Two additional items in natural gas extraction can contribute emissions and releases of sulfur compounds into the atmosphere: (1) equipment failure (e.g., leaks and ruptured pipes) due to corrosion or embrittlement, and (2) improperly plugged wells.

Equipment Failure. H_2S can attack the crystalline matrix of the steel, leading to embrittlement and cracking of the steel, which could, in turn, lead to possible leakage of H_2S. This embrittlement is invisible and can occur in a short period of time. Corrosion, which is caused by chemical reactions of metal with water and H_2S, can also cause H_2S leakage. Because of the corrosive nature of H_2S in the presence of water, oil and gas operations take precautions to remove water from gas streams containing H_2S. The National Association of Corrosion Engineers has a "Standard Material Requirement" entitled "MR-0175-92, Sulfide Stress Cracking Resistant Metallic Materials for Oil Field Equipment" which describes corrosion prevention measures. Corrosion resistant materials, coatings, and chemical corrosion inhibitors may be used to prevent equipment failure and gas releases where H_2S and other corrosives are known to be present (personal communication, Donelson, Texaco, 12/9/92). This type of accidental release is discussed in greater detail in Chapter III.

Well Plugging. Improper well plugging may also be a potential source of H_2S emissions. After all of the recoverable natural resources have been removed from a well, it must be properly plugged to avoid degradation of groundwater and surface water. Plugging involves placing cement within a wellbore at specific intervals to permanently block the possible migration of formation fluids containing H_2S. Improper plugging may allow H_2S (if present) to migrate out of the wellbore and into the atmosphere. Well plugging is regulated by the individual states. Plugging bonds are posted and procedures are subject to the regulatory agency's approval and on-site witness (personal communication, Donelson, Texaco, 12/9/92). This type of accidental release is also discussed in Chapter III.

Stripper Wells

Stripper wells are defined in Appendix A as producing at most 10 barrels of oil per day or 100 thousand cubic feet of gas per day. The owners or operators of these wells are typically smaller producing companies. Although stripper wells are often in remote areas, many are not completely isolated from the public. The potential exists for livestock, wildlife, or humans to come into contact with high levels of H_2S from stripper wells due to routine emissions and accidental releases. Although these wells are a potential hazard, no data were available on the number of sour stripper wells in the United States.

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CHAPTER III
HAZARD ASSESSMENT OF OIL AND GAS WELLS

INTRODUCTION

Objective

The objective of this chapter is to evaluate the potential hazards to public health and the environment resulting from routine emissions and accidental releases of hydrogen sulfide (H_2S) from oil and gas production, i.e., extraction; piping to a separator; oil, gas, and water separation; and associated storage.

Focus of Assessment

This hazard assessment was performed in two parts. First, existing H_2S ambient air monitoring data were compared to studies of human health and environmental effects to determine whether the H_2S concentrations measured from routine emissions have potentially harmful effects. Second, the threat of accidental releases was assessed by identifying past accidents and their impacts, reviewing atmospheric dispersion analyses (i.e., modeling) of accidental release scenarios in the literature, and conducting additional analyses. The result is an assessment of whether routine emissions and accidental releases are at levels that would require a national control strategy. In addition, this assessment identifies the hazards of H_2S, recommended protective levels, and the areas of the United States potentially vulnerable to routine emissions and accidental releases of H_2S.

Scope and Limitations

This hazard assessment addresses hydrogen sulfide emissions and releases that may potentially originate from a range of sources beginning with oil and gas wells (after well development) up through their associated treatment processes, storage units, and piping. However, it does not include gas processing or oil refining plants. For the potential H_2S emission sources described in Chapter II, non-occupational health impacts are considered along with environmental impacts (i.e., wildlife, livestock, and vegetation). For wildlife and livestock, the assessment includes animals that may be exposed to H_2S when they wander onto the well site.

For routine H_2S emissions, this hazard assessment is limited by the lack of data available on ambient air quality around well sites. Only a small amount of ambient monitoring data collected by States was identified. In addition, no national statistics on the health and environmental effects of chronic H_2S exposure exist. Nor are national statistics on the frequency and severity of accidental H_2S emissions or releases available. Only case records were located for the assessment of accidental releases. Therefore, the conclusions drawn from this assessment are based primarily on predictive modeling of accidental releases and on a semi-quantitative comparison of ambient monitoring data and non-specific health effects data.

Hazard Assessment Steps

This hazard assessment was divided into three major parts:

- Hazard Identification
- Exposure Analysis
- Consequence Analysis

Figure III-1 displays the various components of this assessment.

The first step in this assessment was hazard identification. It entailed collecting information on the physical and chemical properties of H_2S and its location in the United States as it occurs (1) naturally in petroleum deposits, and (2) where it has been generated by sulfur-reducing bacteria that are introduced by enhanced oil recovery processes. The primary component of hazard identification is determining hydrogen sulfide's hazardous properties: ignitability, corrosivity, explosivity, and toxicity to human health and the environment.

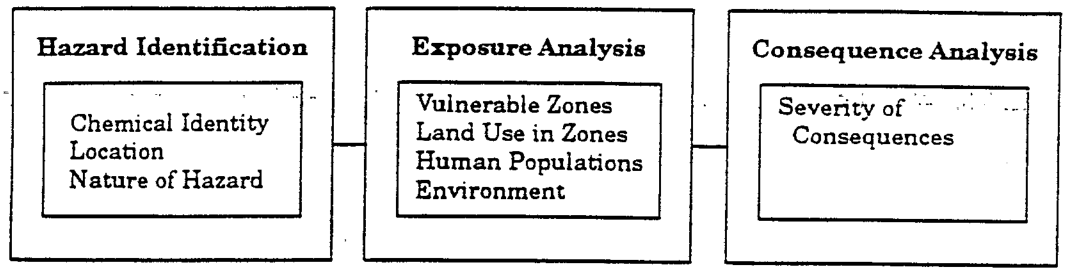
The second step, exposure analysis, included identification of the H_2S prone areas for H_2S exposure in the United States and the human and ecological populations expected to be in these zones. The final part of the assessment, consequence analysis, was an examination of H_2S routine emissions and accidental releases occurring at oil and gas wells and the severity of the consequences.

Since this report examines routine emissions and accidental releases separately, this chapter first presents hazard identification, which is the same for both routine and accidental releases. Next, routine exposure and its consequences are discussed. Finally, exposure to accidental releases and its consequences are presented.

HAZARD IDENTIFICATION

Chemical Identity

Hydrogen sulfide is a colorless, flammable gas which, in low concentrations, has a characteristic odor of rotten eggs. It is a frequent component of crude oil and natural gas. Hydrogen sulfide gas has the Chemical Abstracts Services (CAS) registry number 7783-06-4; its physical and chemical properties are summarized in Table II-1.



Adapted from: U.S. EPA, 1987.

Figure III-1. Components of the hazard assessment exercise.

Location

H_2S is found at varying depths in the earth's geological formations. Underground sources of the gas are often referred to as pockets of H_2S. Other natural sources of H_2S include volcanic gases, sulfur deposits, sulfur springs, and swamp gas from anaerobic decay. Approximately 90 percent of the air emissions of H_2S are produced by natural sources (U.S. EPA, 1993). A portion of this 90 percent results from the routine emissions and accidental releases resulting from the extraction of oil and gas containing H_2S. Figure II-1 shows major H_2S-prone areas of the United States.

Nature of Hazard

Exposure Routes, Absorption, Metabolism, and Elimination

As described in previous chapters, the most rapid route of exposure to H_2S is through the air. Although eye irritation is the basis for the OSHA Permissible Exposure Limit (PEL), inhalation is the quickest lethal exposure to humans and wildlife. The solubility of H_2S in water decreases as temperature increases; however, drinking groundwater has been found with noticeable H_2S concentrations.

Sullivan and Krieger's *Hazardous Materials Toxicology* (1992) summarizes the effects of H_2S exposure as follows:

> In environmental and occupational exposures, the lung rather than the skin is the primary route of absorption (Burgess, 1979; Yant, 1930). The dermal absorption of H_2S is minimal (Laug and Draize, 1942). Results from animal inhalation studies indicate that H_2S is distributed in the body to the brain, liver, kidneys, pancreas, and small intestine (Voigt and Muller, 1955). Within the body, H_2S is metabolized by oxidation, methylation, and reaction with metallo-or disulfide-containing proteins. Orally, intraperitoneally, and intravenously administered H_2S is primarily oxidized and directly excreted as either free sulfate or conjugated sulfate in the urine (Curtis et al., 1972). The importance of methylation in the detoxification processes of H_2S, however, is unknown (Weisiger and Jakoby, 1980). The reaction of H_2S with vital metalloenzymes such as cytochrome oxidase is the likely toxic mechanism of H_2S (NRC, 1979; Smith and Gosselin, 1979). Reaction with nonessential proteins may also serve as a detoxification pathway (Smith, Kroszyna, and Kruszyna, 1976; Smith and Gosselin, 1964). Systemic poisoning occurs when the amount of H_2S absorbed exceeds that which can be detoxified and eliminated (Yant, 1930; Milby, 1962). Because of its rapid oxidation in the blood, H_2S is not considered a cumulative poison (Yant, 1930; Ahlborg, 1951; Haggard, 1925)....

There are no animal data available regarding the exhalation of H_2S after inhalation exposure. In animals, the excretion of H_2S by the lungs is minimal after peritoneal administration of H_2S (Evans, 1967; Gunina, 1957; Susman et al., 1978). However, because rescue personnel have developed H_2S poisoning shortly after starting mouth-to-mouth resuscitation on victims who had been poisoned, it is likely that significant H_2S is excreted from the lungs (Kleinfeld, Giel, and Rosso, 1964).

Acute Human Toxicity

The odor perception threshold for H_2S is very low. At concentrations between 3 and 20 ppb, the characteristic rotten egg odor is detectable. However, higher concentrations of H_2S in the 1.5×10^5 to 2.5×10^5 ppb range can cause olfactory paralysis. At these concentrations, the olfactory sense may be lost and exposed persons may be unaware of the presence of the toxic gas. Thus, odor cannot be relied upon as a warning sign of possible exposure to H_2S. Pulmonary edema, resulting from inhalation of levels between 3×10^5 and 5×10^5 ppb, can be fatal. (See Table III-1.) Inhaling levels between 5×10^5 and 1×10^6 ppb can cause a stimulation of the respiratory system, and rapid breathing (hyperpnea) will occur followed by cessation of breathing (apnea). The effect of inhaling levels above 1×10^6 ppb is immediate respiratory paralysis followed by death.

Inhalation of levels above 2.5×10^5 ppb can damage organs and the nervous system. Much of this damage is a result of a lack of oxygen (anoxia) caused by the depression of cellular metabolism which can occur at 2.5×10^5 ppb. Instances of permanent neurological damage in humans resulting from acute exposure have been described. Furthermore, animal data have revealed that changes in the tissues of the brain, lungs and heart can occur from exposure to the gas.

Irritation of the respiratory tract and eyes is another major effect of H_2S exposure. The gas is readily absorbed through the nasal and lung mucosa. It is very irritating to the respiratory tract and eyes and can cause serious eye injury above 5×10^4 ppb. The gas can affect the epithelium of the eye causing inflammation and lacrimation. The Integrated Risk Information System (IRIS) (U.S. EPA, 1992) lists several signs and symptoms of H_2S exposure including painful conjunctivitis, sensitivity to light, tearing, and clouding of vision. In addition, permanent scarring of the cornea can occur. At high, and potentially lethal concentrations, the mucous membranes can be anesthetized so that irritation effects cannot be relied upon to warn individuals of H_2S exposure.

In addition to irritation, IRIS lists other signs and symptoms of H_2S exposure including labored breathing and shortness of breath, profuse salivation, nausea, vomiting, diarrhea, giddiness, headache, dizziness, confusion, rapid breathing, rapid heart rate, sweating, and weakness.

Table III-1. Effects of Exposure in Humans at Various Concentrations in Air

Clinical Effect	Level of Hydrogen Sulfide ppb	mg/m^3	Reference
Odor perception threshold	3-20	0.004 - 0.028	Indiana Air Pollution Control Board (1964)
Offensive odor (rotten eggs)	$<3x10^4$	<42	Ahlborg (1951)
Offensive odor (sickening sweet)	$>3x10^4$	>42	National Research Council (1977)
Occupational Exposure Limit (OEL)	$1x10^4$	14	National Research Council (1977)
Serious eye injury	$5x10^4$ - $1x10^5$	70 - 140	National Research Council (1977)
Olfactory paralysis	$1.5x10^5$ - $2x10^5$	210 - 350	National Research Council (1977)
Pulmonary edema, threat to life	$3x10^5$ - $5x10^5$	420 - 700	National Research Council (1977)
Strong stimulation of respiration	$5x10^5$ - $1x10^6$	700 - 1400	National Research Council (1977)
Respiratory paralysis, collapse and death	$1x10^6$ - $2x10^6$	1400 - 2800	National Research Council (1977)

Source: U.S. EPA, 1993.

Hydrogen sulfide may also decrease the body's ability to withstand infection. A toxicological study exposed rats to 4.5 x 10^4 ppb of hydrogen sulfide for 2, 4, or 6 hours, followed by a challenge with an aerosol of *staphylococcus epidermis* (Rogers and Ferin, 1981). A significant dose-response effect was seen in the number of colonies formed, when the exsanguinated lungs were harvested from the rats at 30 minutes, 3 hours and 6 hours post-challenge, and homogenized and grown in a selective growth medium for staphylococci. Rats exposed to hydrogen sulfide for 4 hours had a 6.5-fold greater percent of colony-forming units than controls, while those exposed to hydrogen sulfide for 6 hours had a 52-fold greater percent of colony-forming units. The conclusion reached was that hydrogen sulfide significantly affected the antibacterial system of the rats by impairing alveolar macrophages.

However, Higashi et al. (1983), in a cross-sectional study of viscose rayon textile workers exposed to hydrogen sulfide (average concentration, 3 x 10^3 ppb) and carbon disulfide, found no difference between exposed employees and controls in respiratory and spirometric variables. Similarly, Kangas et al. (1984) found no increased prevalence of subjective symptoms among cellulose mill workers exposed to hydrogen sulfide concentrations of up to 2 x 10^4 ppb and methyl mercaptan levels as high as 1.5 x 10^4 ppb, and much smaller amounts of dimethyl disulfide.

<u>Chronic Human Toxicity</u>

The toxicological data based was reviewed and an inhalation reference concentration (RfC) was verified by the U.S. EPA Reference Dose (RfD)/RfC Work Group on June 21, 1990. The documentation is available via the Integrated Risk Information System (IRIS) (U.S. EPA, 1991). The Integrated Risk Information System is an on-line data base containing EPA risk assessment results and regulatory information. An RfC is defined as an estimate, with uncertainty spanning perhaps an order of magnitude, of a daily exposure to the human population (including sensitive subgroups) which is likely to be without adverse effects during a lifetime (U.S. EPA, 1990). The derivation of the RfC is based on a complete review of the toxicological literature and encompasses adjustments for exposure duration and dosimetry. It utilizes uncertainty factors to account for specific extrapolations between the population in which the effect was observed and the human population. The critical, usually the most sensitive, effect is the focus of the RfC derivation; for this effect the no-observed-adverse-effect level (NOAEL), or lowest-observed-adverse-effect level (LOAEL) if a NAOEL is not available, is identified. Detailed discussion concerning these issues can be found in U.S. Environmental Protection Agency, 1990.

The RfC for H_2S is 9 x 10^{-4} mg/m^3 (6.7 x 10^{-1} ppb) and was derived from the NOAEL for inflammation of the nasal mucosa in mice (Toxigenics, 1983). The subchronic study revealed a lowest-observed-adverse-effect level (LOAEL) of 110 mg/m^3 (8 x 10^4 ppb) and a no-observed-adverse-effect level (NOAEL) of 42.5 mg/m^3 (3.05 x 10^4 ppb). Since the RfC may change due to evaluation of additional data, the reader is referred to IRIS for the most current information regarding the RfC for H_2S.

The extrapolation of the NOAEL to the RfC follows several steps. First, the NOAEL is adjusted to account for the daily length of exposure in the study; and second, it is extrapolated to humans, and a human equivalent concentration (HEC) is calculated. Finally an uncertainty factor is applied. The RfC for hydrogen sulfide is derived using an uncertainty factor of 1000. The 1000 reflects a factor of 10 to protect sensitive individuals, 10 to adjust from subchronic studies to a chronic study (a subchronic study is carried out over a shorter period of time and may not accurately reflect cumulative effects), and 10 to adjust for interspecies conversions and database deficiencies.

Very little data exist on whether H_2S can cause carcinogenic, mutagenic, reproductive or developmental effects in humans or animals. Because of a lack of adequate test data, H_2S is currently placed in Group D, based on the weight-of-evidence criteria in the EPA's Carcinogen Risk Assessment Guidelines issued in August 1986. A Group D ranking means that the available data are inadequate to assess a chemical's human carcinogenic potential. Furthermore, data are inadequate to state that H_2S is mutagenic or that it causes reproductive effects. Limited animal data do suggest that H_2S appears to have potential to alter normal developmental processes. No data on human developmental effects of inhaled H_2S have been located (U.S. EPA, 1993).

Ecological Effects

Data on the ecological effects of H_2S are limited (Table III-2). McCallan, Hartzell, and Wilcoxon (1936) and Benedict and Breem (1955) conducted high-exposure fumigation studies, which noted that young, growing plants were the most susceptible to injury from exposure to H_2S. However, they noted that temperature, soil moisture, and species differences were important factors affecting the results. Heck, Daines, and Hindawi (1970) noted that mature leaves were unaffected while damage to the young shoots and leaves consisted of scorching. Among the plants determined to be sensitive to H_2S are clover, soybean, tomatoes, tobacco, and buckwheat.

According to the EPA *Health Assessment Document for H_2S* (U.S. EPA, 1993), few studies exist that evaluate natural or accidental exposure of wildlife and/or domestic animals to H_2S. However, H_2S has been determined to be highly toxic to some fish species. Animal surveys conducted after a gas well blowout in Lodgepole, Alberta, Canada (Lodgepole Blowout Inquiry Panel, 1984; Harris, 1986) revealed that large animals were exhibiting signs of mucous membrane irritation and were avoiding the geographic area. Most cattle in the exposed area were unaffected. Concentrations of H_2S as high as 1.5×10^4 ppb (sampling time unknown) were measured in the blowout area.

Flammability, Explosivity, and Corrosivity

"Hydrogen sulfide is generally stable when properly stored in cylinders at room temperature. However, in the air, it is flammable and explosive and may be ignited by static discharge. It may react with metals, oxidizing agents, and acids such as nitric acid, bromine

Table III-2. Effects of Ecological Exposure to H_2S

Studies	Species	Level			Source
Aquatic	Bluegill	LC_{50}	0.009 - 0.0478	mg/L	AQUIRE
	Rainbow Trout	LC_{50}	0.013 - 0.047	mg/L	AQUIRE
	Fathead Minnow	LC_{50}	0.007 - 0.776	mg/L	AQUIRE
Mammalian	Mouse	NOAEL	42.5 mg/m^3	($3.05x10^4$ ppb)	IRIS
		LOAEL	100 mg/m^3	($8x10^4$ ppb)	IRIS
	Rat	NOAEL	42.5 mg/m^3	($3.05x10^4$ ppb)	IRIS
		LOAEL	100 mg/m^3	($8x10^4$ ppb)	IRIS

AQUIRE Aquatic Toxicity Information Retrieval
IRIS Integrated Risk Information Service

LC_{50} Lethal Concentration 50
NOAEL No-observed-adverse-effect-level
LOAEL Lowest-observed-adverse-effect-level

pentafluoride, chlorine trifluoride, nitrogen triiodide, nitrogen trichloride, oxygen difluoride, and phenyldiazonium chloride. When heated to decomposition, it emits highly toxic sulfur oxide fumes" (Sullivan and Krieger, 1992). In pure form, its lower and upper explosive limits are 4.3 percent (4.3×10^7 ppb) and 45.5 percent (45.5×10^7 ppb), and its auto-ignition temperature is 260 °C (500 °F) (NIOSH, 1977). The National Fire Protection Association (NFPA) has classified hydrogen sulfide in the highest flammability class (NFPA, 1974).

In the presence of water, hydrogen sulfide gas is highly corrosive to metals, including high-tensile steel, which hydrogen sulfide can embrittle. These properties can lead to loss of containment and accidental releases from ruptures if not controlled. Special precautions must be taken to prevent spontaneous ignition fires when vessels that previously contained concentrated hydrogen sulfide are opened. Ignition is caused by reaction of iron sulfide with air to form iron oxide. The conversion of sulfide to oxide produces enough heat to ignite flammable vapors (Dosch and Hodgson, 1986).

ACGIH Threshold Limits

The American Conference of Governmental Industrial Hygienists (ACGIH) publishes a book of threshold limit values for chemical substances in the work environment (ACGIH, 1992). The limits are intended for use in the practice of industrial hygiene as guidelines or recommendations in the control of potential health hazards. When OSHA began setting standards for employee exposure in the 1970s, they adopted the ACGIH threshold limit values (TLV's) as their permissible exposure limits. The ACGIH standards are recommendations rather than regulations; they are updated annually and respond to current research more quickly than OSHA's regulations.

The current limits for H_2S were adopted by ACGIH in 1976. The Threshold Limit Value-Time Weighted Average (TLV-TWA) is 1×10^4 ppb or 14 mg/m^3, and the TLV short-term exposure limit (TLV-STEL) is 1.5×10^4 ppb or 21 mg/m^3. The TLV-TWA is defined as the time-weighted average concentration for a normal 8-hour workday and 40-hour workweek, to which nearly all workers may be repeatedly exposed, day after day, without adverse effect. The TLV-STEL is defined as the concentration to which workers can be exposed continuously for a short period of time without suffering from 1) irritation, 2) chronic or irreversible tissue damage, or 3) narcosis of sufficient degree to increase the likelihood of accidental injury, impair self-rescue or reduce work efficiency, also provided that the daily TLV-TWA is not exceeded. A STEL is further defined as a 15-minute TWA exposure which should not be exceeded at any time during a workday even if the TWA is within the TLV-TWA. Exposures above the TLV-TWA up to the TLV-STEL should not be longer than 15-minutes and should not occur more than 4 times a day, and should be separated by 60 minutes each.

LC_{01}

One measure of the airborne concentrations of toxic materials that might cause fatality is the LC_{01}, which is the concentration that could prove fatal to one percent of those exposed to it. The LC_{01} is related to the exposure time, t, by a relationship of the form $LC_{01} = (k/t)^{1/n}$, where k and n are constants that depend on the material in question. This relationship is a manifestation of the probit equation, which is a well-established way of presenting the relationship between concentration, exposure time, and probability of fatality.

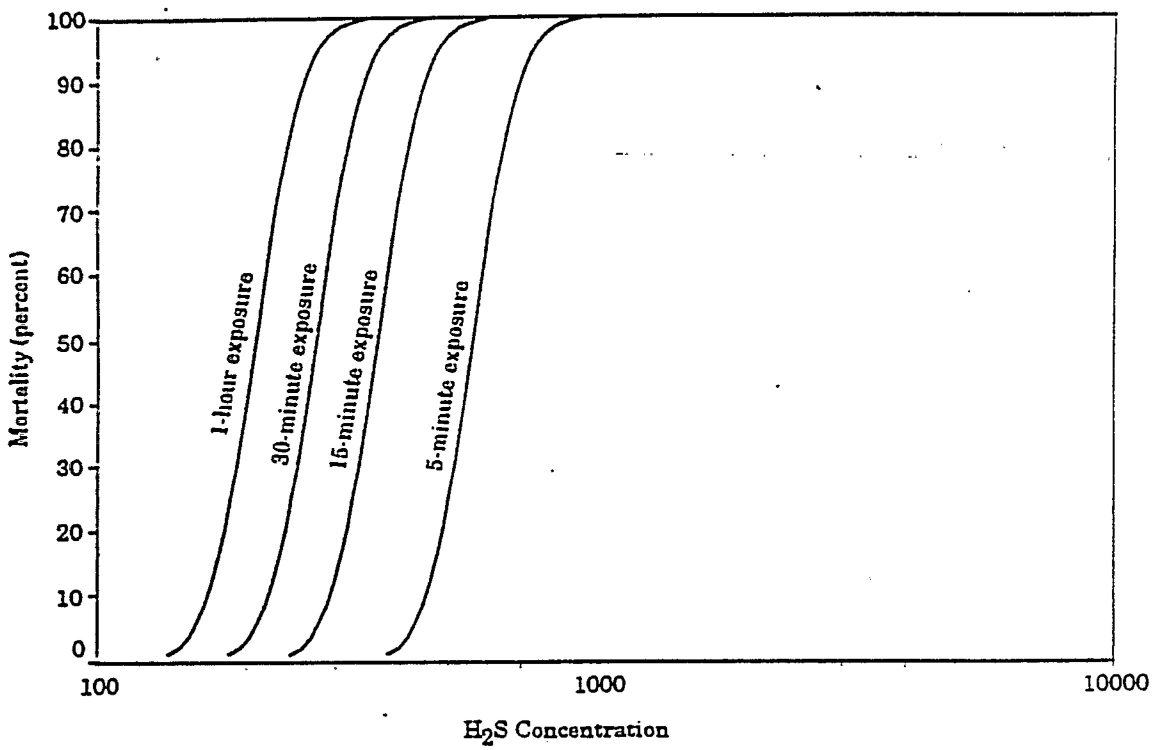
For H_2S, the Center for Chemical Process Safety of the American Institute of Chemical Engineers (AIChE) has a probit equation which gives $k = 83{,}500$ and $n = 1.43$, with C in ppb and t in minutes (AIChE, 1989). Thus, for a five minute exposure, $LC_{01} = 8.95 \times 10^5$ ppb and, for a one hour exposure, $LC_{01} = 1.6 \times 10^5$ ppb.

The Energy Resources Conservation Board (ERCB) of Alberta, Canada (Alp et al., 1990) has developed an alternative probit equation (shown in Figure III-2) which, for the LC_{01}, gives $k = 1.364 \times 10^8$ and $n = 2.5$. For a five minute exposure, this gives $LC_{01} = 3.75 \times 10^5$ ppb and for a one hour exposure gives $LC_{01} = 1.4 \times 10^5$ ppb. The ERCB values are thus more conservative.

AIHA Guidelines

The American Industrial Hygiene Association (AIHA) sets Emergency Response Planning Guidelines (ERPGs) to protect the general public in the event of an emergency release. The three ERPGs for H_2S, which are time-dependent levels for varying degrees of potential harm, are defined as follows:

- ERPG-3: 1×10^5 ppb, the maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing or developing life-threatening health effects;
- ERPG-2: 3×10^4 ppb, the maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing or developing irreversible or other serious health effects or symptoms which could impair an individual's ability to take protective action.
- ERPG-1: 100 ppb, the maximum airborne concentrations below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing other than mild, transient adverse health effects or without perceiving a clearly defined objectionable odor.



Note: Concentrations intentionally left in ppm.
Source: Alp et al., 1990.

Figure III-2. ERCB H_2S probit relations.

For hydrogen sulfide, the ERPG-3 is based on human experience, while the ERPG-2 is based on animal studies and the ERPG-1 is based on the fact that the objectionable odor of hydrogen sulfide is distinct at 300 ppb (AIHA, 1991). For the purposes of accidental release dispersion analysis, the ERPG-2 was considered conservative and used as a threshold for emergency countermeasures.

As stated above, these ERPG values are for an exposure time of one hour. At the time of writing, there is no definitive guidance on how to extrapolate to shorter durations of exposure. However, Gephart and Moses (1989) suggest that a constant dosage extrapolation might be reasonable; that is, (ERPG in ppb)x(exposure time, t, in minutes). = constant, k. Discussions with one of the AIHA authors have suggested that, for $t < 15$ min, k should be divided by two. Thus, for H_2S, the ERPG-2 is as follows:

- 3×10^4 ppb for an exposure time of one hour
- 1.8×10^5 ppb for an exposure time of five minutes.

The reader should recognize that these extrapolations are tentative and included for purposes of illustration. They represent one of the greater sources of uncertainty in the calculations.

NAS/NRC Guidelines

For the last forty years, the NRC's Committee on Toxicology has submitted emergency exposure guidelines for chemicals of concern to the Department of Defense (DOD) (NRC, 1986). These guidelines are used in planning for sudden contamination of air during military and space operations; specifically, they are used to choose protective equipment and reponse plans after non-routine but predictable occurrences such as line breaks, spills, and fires. These guidelines are for peak levels of exposure considered acceptable for rare situations, but are not to be applied in instances of repeated exposure.

An Emergency Exposure Guidance Level (EEGL) is defined as a concentration of a substance in air (gas, vapor, or aerosol) judged by DOD to be acceptable for the performance of specific tasks by military personnel during emergency conditions lasting 1 to 24 hours. Exposure to an EEGL is not considered safe, but acceptable during tasks which are necessary to prevent greater risks, such as fire or explosion. Exposures at the EEGLs may produce transient central nervous system effects and eye or respiratory irritation, but nothing serious enough to prevent proper responses to emergency conditions.

Since the 1940's, the NRC has developed EEGLs for 41 chemicals, 15 of which are listed in Section 302 of the Emergency Planning and Community Right-to-Know Act of 1986 (EPCRA) as extremely hazardous substances (EHSs). Although acute toxicity is the primary basis for selecting EEGLs, long-term effects from a single acute exposure are also evaluated for developmental, reproductive (in both sexes), carcinogenic, neurotoxic, respiratory and other organ-related effects. The effect determined to be the most seriously debilitating, work-limiting, or sensitive is selected as the basis for deriving the EEGL. This concentration is intended to be sufficiently low to protect against other toxic effects that may occur at higher concentrations. Factors such as age of the exposed population, length of exposure, and susceptibility or sensitivity of the exposed population are also considered in determining EEGLs.

Safety factors are used in developing EEGLs to reflect the nature and quality of the data. Safety factors for single exposures may differ from those used in chronic studies. In the absence of better information, a safety factor of 10 is suggested for EEGLs (i.e., the reported toxicity value should be divided by 10) if only animal data are available and extrapolation from animals to humans is necessary for acute, short-term effects (NRC, 1986). The safety factor of 10 takes into account the possibility that some individuals might be more sensitive than the animal species tested. A factor of 10 is also suggested if the likely route of human exposure differs from the route reported experimentally (NRC, 1986), for example, if oral data are reported and inhalation is the most likely exposure route for humans.

As noted by NRC (1986, p. 7), development of an EEGL for different durations of exposure usually begins with the shortest exposure anticipated (i.e., 10-15 minutes) and works up to the longest, such as 24 hours. For H_2S, 10-minute emergency exposure guideline level (EEGL) is 5×10^4 ppb; 1×10^4 ppb is the 24-hour EEGL. The 24-hour/day, 90-day continuous exposure guide level (CEGL) for H_2S has been recommended at 1×10^3 ppb (NCCT, 1985). Under the simplest framework, Haber's law is assumed to operate, with the product of concentration (C) and time (t) as a constant (k) for all the short periods used (Ct=k) (Casarett and Doull, 1986). If Ct is 30 and t is 10, then C is 3; if Ct is 30 and t is 30, then C is 1. If detoxification or recovery occurs and data are available on 24-hour exposures, this is taken into account in modifying Ct. In some instances, the Ct concept will be inappropriate, as for materials such as ammonia that can be more toxic with high concentrations over short periods. Each material is considered in relation to the applicability of Haber's law.

Generally, EEGLs have been developed for exposure to single substances, although emergency exposures often involve complex mixtures of substances and, thus, present the possibility of toxic effects resulting from several substances. In the absence of other information, guidance levels for complex mixtures can be developed from EEGLs by assuming as a first approximation that the toxic effects are additive. When the chemical under evaluation for development of an EEGL is an animal or human carcinogen, a separate qualitative risk assessment is undertaken in recognition of the fact that even limited exposure to such an agent can theoretically increase the risk of cancer. The risk assessment is performed with the aim of providing an estimate of the acute exposure that would not lead to an excess risk of cancer greater than 1 in 10,000 exposed persons. The following mathematical approach, taken directly from NRC (1986, pp. 26-27), is applicable for EEGL computations for carcinogens:

1. If there has been computed an exposure level d (usually in ppm in air), which after a lifetime of exposure is estimated to produce some "acceptable" level of excess risk of cancer — say, 1×10^{-6} — this has been called a "virtually safe dose" (VSD). Computation of the dose d, if not already done by a regulatory agency, will be computed by the Committee on Toxicology in accordance with generally accepted procedures used by the major regulatory agencies, i.e., using the multistage no-threshold model for carcinogenesis and the appropriate body weight/surface area adjustments when extrapolating from an animal species to humans.

2. If carcinogenic effect is assumed to be a linear function of the total (cumulative) dose, then for a single 1-day human exposure an acceptable dose (to yield the same total lifetime exposure) would be d times 25,600 (there being approximately 25,600 days in an average lifetime); the allowable 1-day (24-h) dose rate would be

$$d \times 25{,}600$$

3. Because of uncertainties about which of several stages in the carcinogenic process a material may operate in, and because of the likely low age of military persons, it can be shown from data of Crump and Howe (1984) that the maximal additional risk that these considerations contribute is a factor of 2.8. As a conservative approach, the acceptable dose is divided by 2.8, i.e.,

$$\frac{d \times 25{,}600}{2.8}$$

If a lifetime excess risk, R, is established by DOD (for example, at 1×10^{-4}, as has been suggested by the International Council on Radiation Protection for nuclear power plant workers), then the appropriate extent of risk at the EEGL would be

$$\frac{d \times 25{,}600}{2.8} \times \frac{R}{\text{level of risk at d}}$$

(In the example given here, the level of risk at d was no more than 1×10^{-6}.) If R is 1×10^{-4}, then R/risk at d = $10^{-4}/10^{-6}$ = 100 (NRC, 1986).

4. If a further element of conservatism is required (for example, where animal data need to be extrapolated to estimate human risk), an additional safety factor can be used as divisor.

The NRC's Committee on Toxicology has also developed special public exposure guidelines upon request from Department of Defense. The Short-term Public Exposure Guidance Level (SPEGL) is defined as an acceptable ceiling concentration for a single, unpredicted short-term exposure to the public. The exposure period is usually calculated to be one hour or less and never more than 24 hours. SPEGLs are generally set at 0.1 to 0.5 times the EEGL. A safety factor of 2 is often used to take into account effects on sensitive subpopulations, such as children, the aged, and people with debilitating diseases. A safety factor of 10 may be used to take into account the effects of an exposure on fetuses and newborns. Effects on the reproductive capacity of both men and women are also considered. Five SPEGLs (for hydrazine, dimethylhydrazine, monomethyl hydrazine, nitrogen dioxide, and hydrogen chloride) have been developed by the NRC; all five chemicals are on the list of EHSs. (U.S. EPA, 1987).

EXPOSURE AND CONSEQUENCE ANALYSES

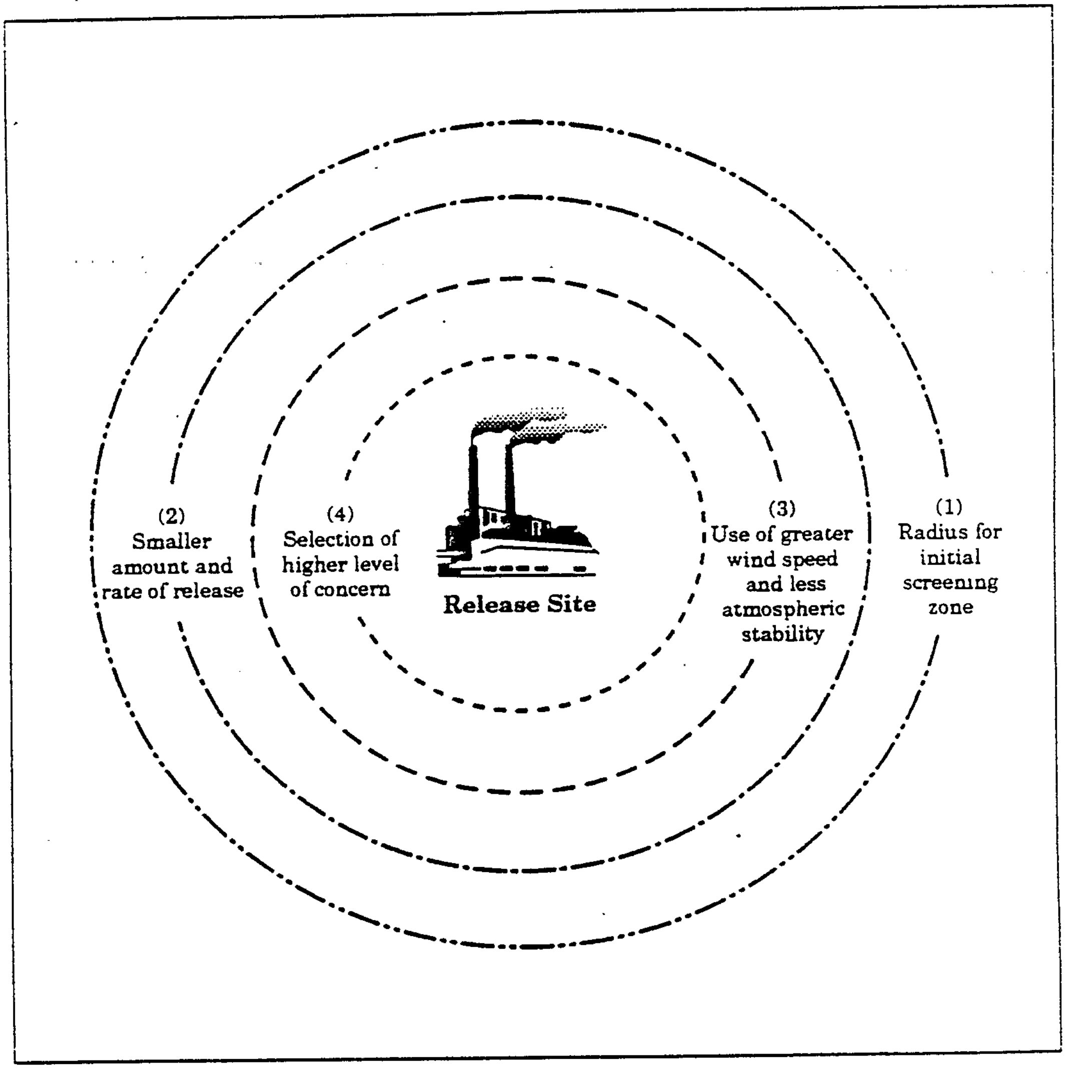
In this section, potential exposures to and consequences of exposure to H_2S from oil and gas wells are analyzed. The zones of the United States most likely to contain H_2S are identified and the potentially exposed human and ecological populations are discussed. Routine emissions and accidental releases of H_2S are characterized using monitoring records and dispersion modeling and the consequences are discussed. For accidental releases, prevention, mitigation and emergency response policies and procedures are also identified.

Vulnerability Zones

Vulnerability zones are estimated geographical areas that may be subject to concentrations of H_2S at levels that could cause irreversible acute health effects or death to human populations within the area following an accidental release. For detailed hazard analyses recommended under the Emergency Planning and Community Right-to-Know Act of 1986 (EPCRA), see Chapter IV; vulnerability zones are based on estimates of the quantity of hazardous substances released to air, the rate of release to air, airborne dispersion, and the airborne concentration that could cause irreversible health effects or death. This concept of vulnerability is used to assess regions most likely to encounter routine emissions or accidental H_2S releases from oil and gas production. This report does not use the EPCRA methodology. Rather, the basic tools of a hazard analysis are used to alert the reader to areas with potential H_2S hazards.

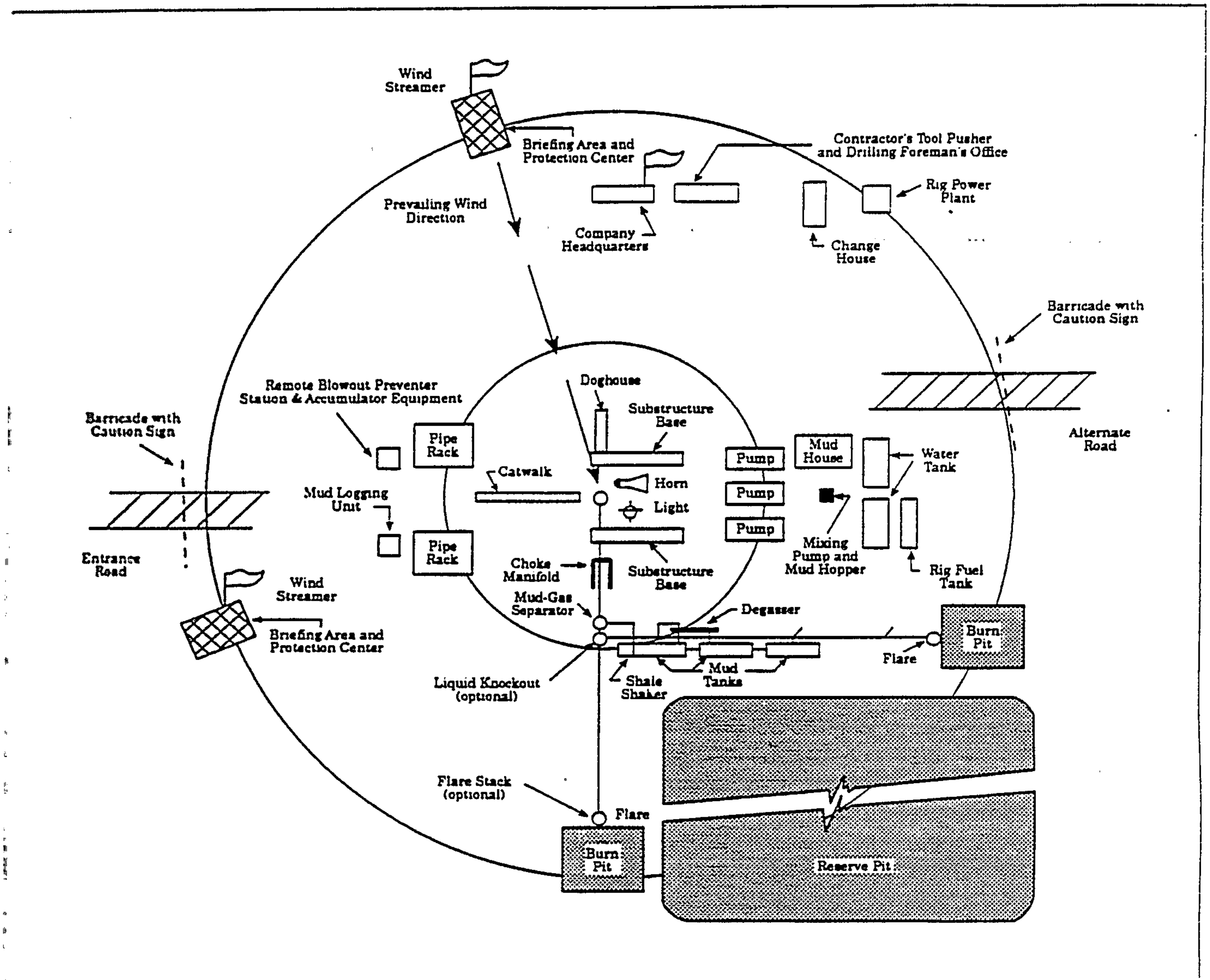
Estimated vulnerability zones are shown in Figure III-3 as circles with different radii to illustrate how changing conditions or assumptions can influence the vulnerablity zone estimate. With most atmospheric releases, the actual concentration of the airborne chemical tends to decrease as it moves further downwind from the release site because of continual mixing and dilution (i.e., dispersion).

The American Petroleum Institute (API), an industry-wide technical organization, has published several recommended practices (RP) pertaining to hydrogen sulfide in the oil and gas production industry. Figure III-4 shows API's RP 49 recommended equipment layout to minimize vulnerability zones for an unconfined area, taking the potential for H_2S releases into consideration. Confinement refers to offshore sites and some land locations confined by



Source: U.S. EPA. 1987.

Figure III-3. The effect of different assumptions on the calculation of the radius of estimated vulnerable zones.



Source: API, 1987.

Figure III-4. Example of drilling equipment layout – unconfined location.

the restriction of area, method of access, terrain, surrounding population distribution, etc. In an H_2S environment, well plot areas should be larger than usual, (i.e., larger reserve pits, turnaround room, etc.). The extra space allows for a greater margin of safety in well site activities and, in turn, a smaller vulnerability zone.

The California Division of Oil and Gas provides guidance on H_2S exposure prevention. In their report, *Drilling and Operating Oil, Gas, and Geothermal Wells in an H_2S Environment*, the State recommends calculating the well area's potential toxicity from H_2S emissions, if the volume of oil or gas produced and the concentration of the H_2S in the oil or gas are known (Dosch and Hodgson, 1986). From these data, the radius from the source to the 3×10^5 ppb and 1×10^5 ppb H_2S concentration area can be determined on dispersion-based scales. Potential sources of toxic gas emissions considered in calculating the toxicity of the well area include wells and associated production, treatment, processing, and storage facilities.

Calculating vulnerability zones for H_2S on a nationwide basis, as in EPCRA hazard analyses, is difficult because vulnerability zones are designed for site-specific studies. Therefore, this assessment will take a broader approach to identifying vulnerability zones, which will be referred to as H_2S prone areas. These areas are considered the major areas of the United States prone to natural occurrences of hydrogen sulfide. Figure II-1 identified 14 major H_2S prone areas in the United States. The 20 states having H_2S prone areas are Alabama, Arizona, Arkansas, California, Colorado, Florida, Idaho, Indiana, Illinois, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Nebraska, North Dakota, Oklahoma, Texas, Utah, and Wyoming. Texas has four discrete areas prone to H_2S. However, some States, such as Louisiana, do not drill to depths of known H_2S deposits; in Louisiana, oil and gas wells appear to be located in more shallow depths.

Exposure Analysis — Routine Emissions

Monitoring Records

Ambient air monitoring programs measure the concentration of pollutants after they have dispersed from one or more sources. These levels are recorded and tracked continuously so that the level of exposure and air quality can be assessed over the long term and under varying meteorological and emission scenarios. Ambient air monitoring is also used to determine compliance with air quality standards by measuring pollutant concentrations. With a dispersed, relatively unreactive primary pollutant such as hydrogen sulfide, often the emissions can be traced back to the specific source.

Many States require ambient air monitoring for hydrogen sulfide at gas plants and refineries; however, monitoring is not frequently required at oil and gas extraction facilities. In the preparation of this report, six States (California, Michigan, North Dakota, Oklahoma, Texas, and Wyoming) were contacted and questioned about the availability of monitoring data. California, Michigan, Oklahoma, Texas and Wyoming had not conducted pertinent ambient air monitoring.

The North Dakota State Department of Health and Consolidated Laboratories (NDSDH&CL) performs ambient monitoring for routine emissions of H_2S and has collected the data since 1980. The following discussion summarizes North Dakota's program to provide an indication of historical, routine emissions of H_2S from wells. Since no other States have such monitoring data available, this report relies on North Dakota's data to assess hazards and draw conclusions.

The North Dakota database contains site name, year/month/day monitored, and H_2S value measured. The database reflects three background and six special purpose monitors (i.e., monitors set up as a result of a complaint). Monitoring periods vary in length from months to over a decade for a total of 393 months (32.75 years) of data (personal communication, D. Harman, NDSDH&CL, 8/11/92). Table III-3 shows the North Dakota data. The data were in half-hour average concentrations up to January 1, 1988, when the averages recorded were changed to hourly, to correspond with the change in the North Dakota Ambient Air Quality Standards (NDAAQS). Some monitoring lasted less than a year; however, monitoring in the Theodore Roosevelt National Park-north unit was begun in 1980 and continues today.

North Dakota's Hydrogen Sulfide Standards - An Historical Review. At the time of the early monitoring activities, there were two NDAAQS for hydrogen sulfide, both based on half-hour averages and on odor thresholds but over different time spans. Adopted in 1970, they were based upon guidelines established in the Interstate Air Pollution Study conducted in St. Louis in the late 1960s. Those standards were 54 ppb (75 $\mu g/m^3$), 1/2-hour maximum concentration not to be exceeded more than twice per year; and 32 ppb (45 $\mu g/m^3$), 1/2-hour maximum concentration not to be exceeded more than twice in any five consecutive days. The 1/2-hour hydrogen sulfide standards were inconvenient because all of the other pollutants were being tracked on an hourly basis. To correct the situation, North Dakota developed a 1-hour standard that would afford the same degree of protection as the old 1/2-hour standards did, while still based on an odor threshold value. Statistically, they narrowed the proposed standard down to a range of concentrations between 48 ppb and 52 ppb. Montana had an existing hydrogen sulfide standard of 50 ppb for a 1-hour period, not to be exceeded more than once per year, and North Dakota decided to adopt the same standard to provide consistency on both sides of the North Dakota-Montana State border. The 50 ppb (70 $\mu g/m^3$) 1-hour hydrogen sulfide standard became effective October 1, 1987.

At the same time that the new standard became effective, a new chapter (Chapter 20) was added to North Dakota's Air Pollution Control Rules entitled "Control of Emissions from Oil and Gas Well Production Facilities." The oil companies expressed concern that the hydrogen sulfide standard was included in North Dakota's table of ambient air quality standards (NDAAQS) and, by law, exceptions could not be granted. Their position was that they could not guarantee compliance with the standard at all times, and that the standard was

Table III-3. North Dakota H_2S Monitoring Studies

Study	Location	Dates	Year	Ambient Std. (ppb)	Violation* (hours)	Maximum (ppb)
Roffler	Farmyard within 1/2 mile of well and tank battery	5/11/80 - 9/29/80	1980	32	0	13
Theodore Roosevelt National Memorial Park – North Unit	Little Missouri River Valley, near the north unit park headquarters	4/24/80 - 8/2/92 (1990 missing)	1980	32	0	4
			1981	32	1	220
			1982	32	34	500
			1983	32	31	158
			1984	32	27	415
			1985	32	35	137
			1986	32	12	87
			1987	32/50	0	73**
			1988	50	0	39
			1989	50	0	10
			1990	50/200	0	10
			1991	200	0	32
			1992	200	0	6
orgenson	Valley with several oil wells within 1 mile	10/2/80 - 5/13/82	1980	32	8	160
			1981	32	19	230
			1982	32	13	250
adrmas	Farmyard within 1 mile of several wells	6/30/82 - 10/31/83	1982	32	9	541
			1983	32	7	353
heodore Roosevelt ational Memorial ark – South Unit	Painted Canyon Rest Area	10/17/85 - 6/30/90	1985	32	0	12
			1986	32	0	16
			1987	32/50	0	18
			1988	50	0	9
			1989	50	0	10
			1990	50/200	0	0*
one Butte	Little Missouri River Valley near an oil tank battery in Little Knife Oil Field	1/17/84 - 7/11/89	1984	32	1808	1630
			1985	32	1859	2734
			1986	32	1653	2182
			1987	32/50	1130	2420
			1988	50	320	1515
			1989	50	25	122
ostwood	Lostwood National Wildlife Refuge Headquarters	12/26/85 - 1/14/91	1985	32	0	0
			1986	32	0	18
			1987	32/50	0	45
			1988	50	0	46
			1989	50	0	47
			1990	50/200	0	88
			1991	200	0	0
son	Farmyard within 1.5 miles of several wells	7/20/89 - 9/18/90	1989	50	2	88
			1990	50/200	0	73
aza	Town of Plaza, within 2 miles of several wells and tank batteries	9/4/90 - 8/3/92	1990	50/200	0	152
			1991	200	0	358
			1992	200	1	269

urce: Personal correspondence, D. Harman, NDSDH & CL, 8/11/92.

alysis of data prior to 10/1/87 based upon 32 ppb, 1/2-hour average standard, not to be exceeded more than twice in any onsecutive days.

alysis of data between 10/1/87 and 6/1/90 based upon 50 ppb 1-hour average standard, not to be exceeded more than once r year.

alysis of data after 6/1/90 based upon 200 ppb 1-hour average standard, not to be exceeded more than 1 time per month.

violation occurs the second time the standard is exceeded.

Monitor out of service much of the time period.

Exceedance defined as 2 times the standard.

not based on health-related concerns but on odor recognition levels. As a result, a joint Health Department/Industry task force was established and four new health-based standards were developed (effective June 1, 1990). These included raising the 50 ppb, 1-hr standard to a 200 ppb, 1-hr standard - a decrease in H_2S protection by a factor of four. These standards, which remain in effect today, are as follows:

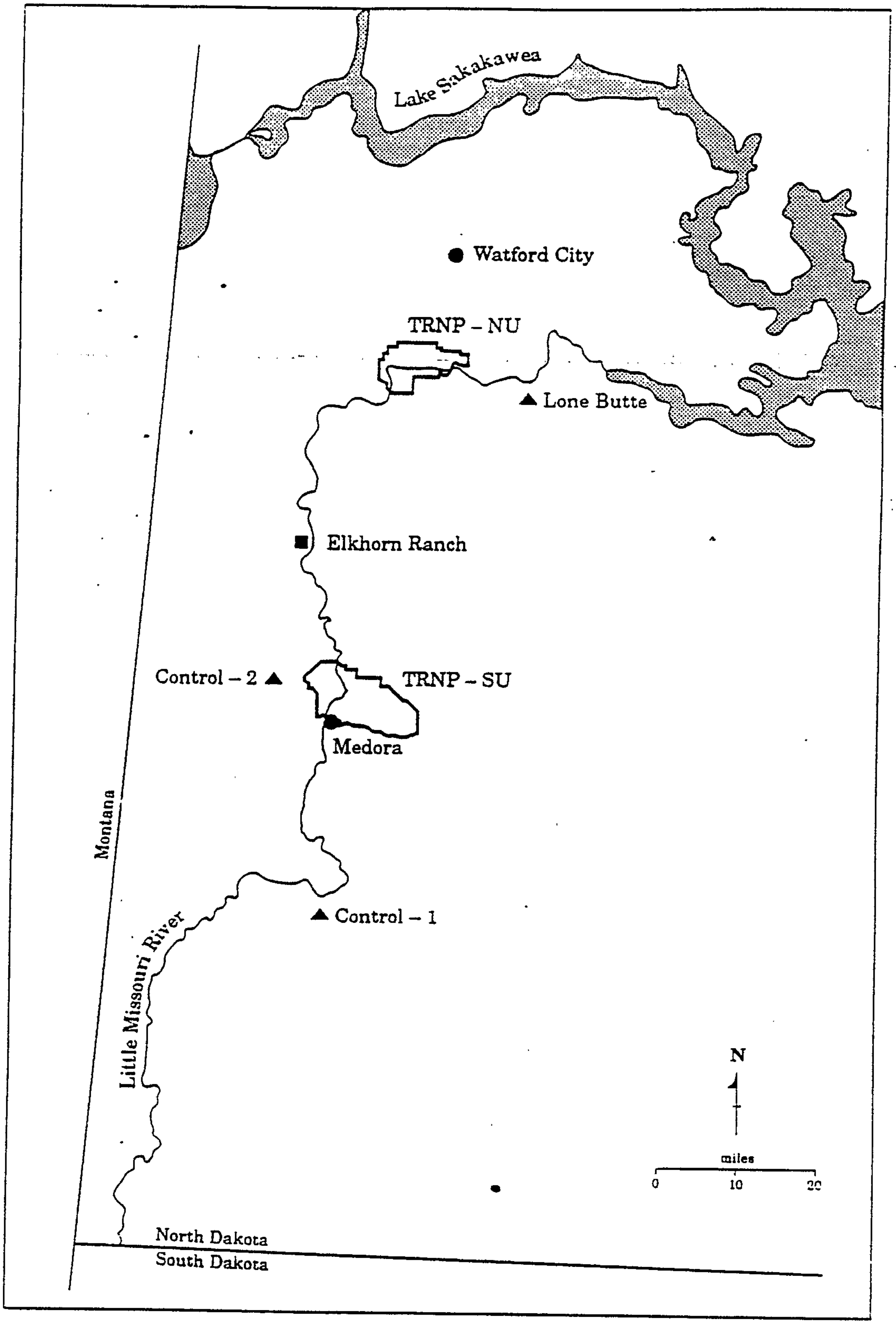
- 1×10^4 ppb or 14 mg/m^3) maximum instantaneous concentration not to be exceeded;
- 200 ppb or 280 μg/m^3) maximum 1-hour average concentration not to be exceeded more than once per month;
- 100 ppb or 140 μg/m^3) maximum 24-hour average concentration not to be exceeded more than once per year;
- 20 ppb or 28 μg/m^3) maximum arithmetic mean concentration averaged over three consecutive months (personal communication, D. Harman, NDSDH&CL, 8/11/92).

Methodology for Analysis of Monitoring Data. For the analysis of the monitoring data, only one of the standards was evaluated for each time period. Prior to October 1, 1987, the data were compared to the 32 ppb 1/2-hour average standard, not to be exceeded more than twice in any five consecutive days. After October 1, 1987, and prior to June 1, 1990, 50 ppb was the only standard in effect, not to be exceeded more than once per year. The data collected after June 1, 1990, were compared to the 200 ppb standard which was not to be exceeded more than once per month. The results of the analysis are tabulated in Table III-3.

PSD Class I Areas. Several of the North Dakota monitoring programs were conducted to monitor air quality changes resulting from the oil and gas production industry at national parks and wildlife refuges. The Federal government established the Prevention of Significant Deterioration permit program (PSD) to protect areas with good air quality. In North Dakota, the most important, or Class I, areas include the Lostwood National Wildlife Refuge and the northern, southern and Elkhorn Ranch portions of the Theodore Roosevelt National Park (see Figure III-5). Monitoring sites for hydrogen sulfide were set up at all of these locations except the Elkhorn Ranch locations.

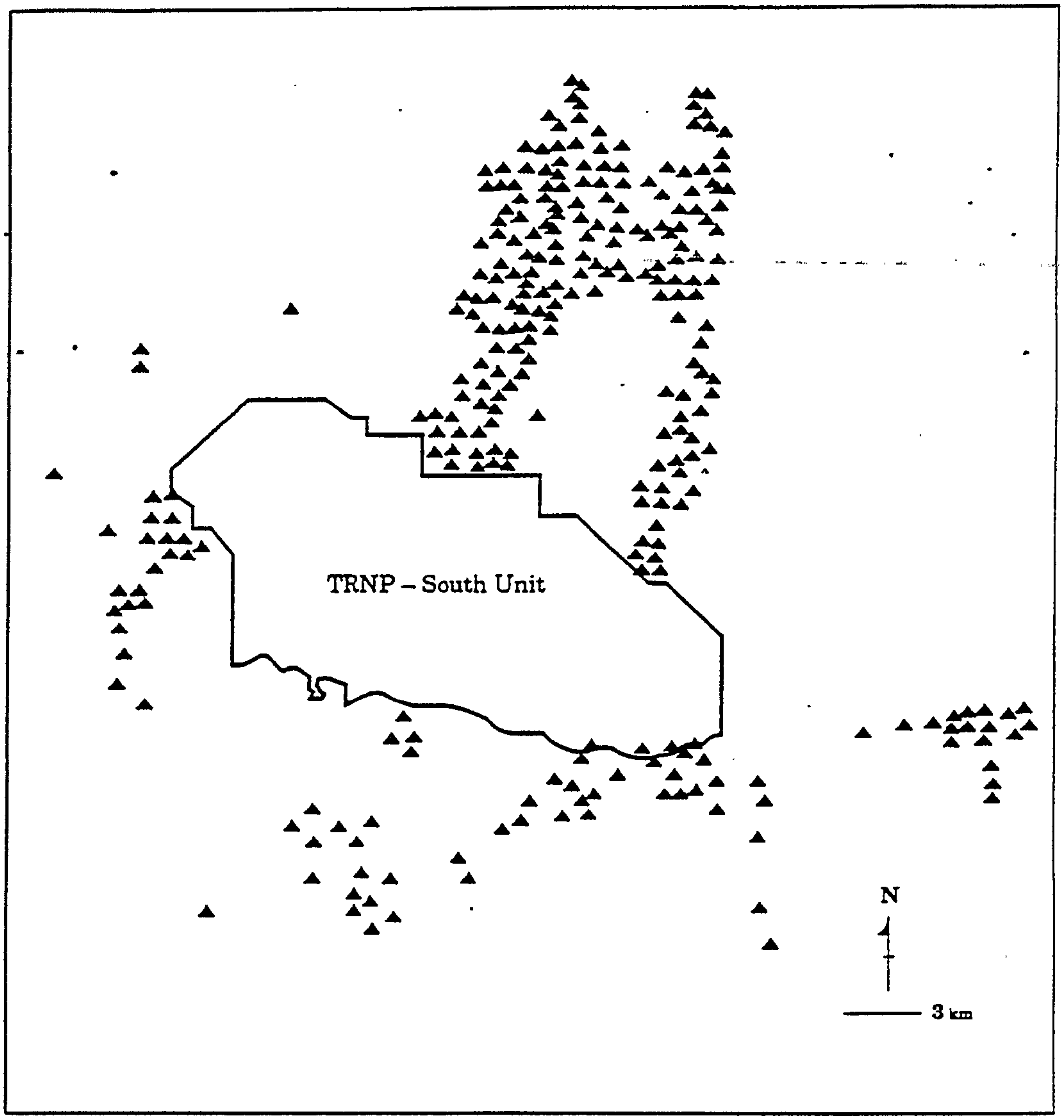
At the Lostwood Wildlife Refuge, data were obtained for the period from December 26, 1985, until January 14, 1991. Throughout the time period the maximum average concentration was 88 ppb, recorded as a 1-hour average in 1990. Overall, this was a site with acceptable air quality with respect to hydrogen sulfide because there were no NDAAQS violations.

In the Theodore Roosevelt National Park system (see Figures III-6 and III-7 for well distribution around the park), data were received by NDSDH&CL for the south unit (obtained at the Painted Canyon Rest Area) from October 17, 1985, to June 30, 1990. The air quality was very good, with no NDAAQS violations, and a maximum half-hour average



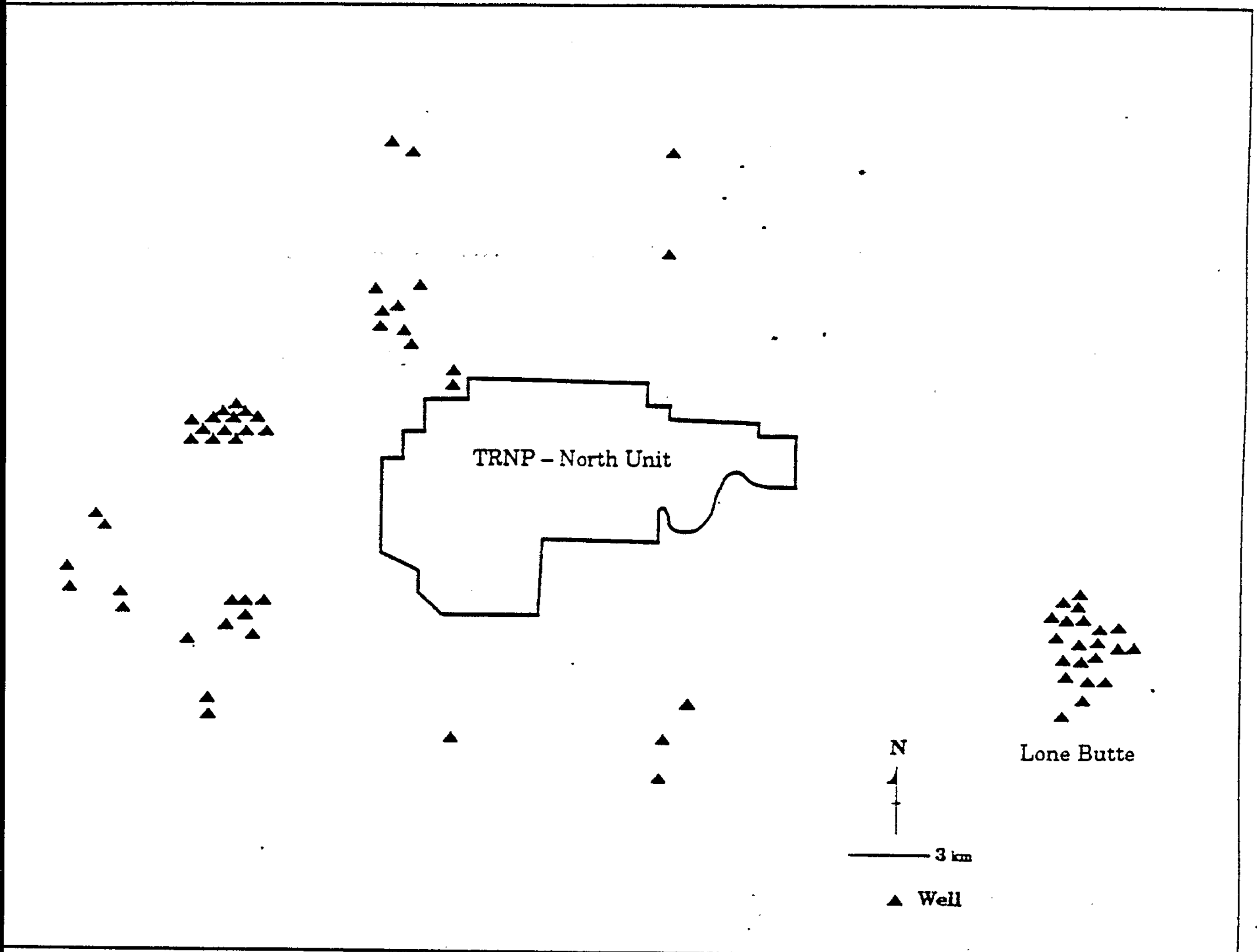
Source: Bilderbeck, 1988.

Figure III-5. Class I and II areas of North Dakota including Lone Butte and Theodore Roosevelt National Park (TRNP). Bold outlined areas are Class I; remaining area is Class II.



Source: Bilderbeck, 1988.

Figure III-6. Well distribution around Theodore Roosevelt National Park, South Unit.



urce: Bilderbeck, 1988.

gure III-7. **Well distribution around Theodore Roosevelt National Park, North Unit.**

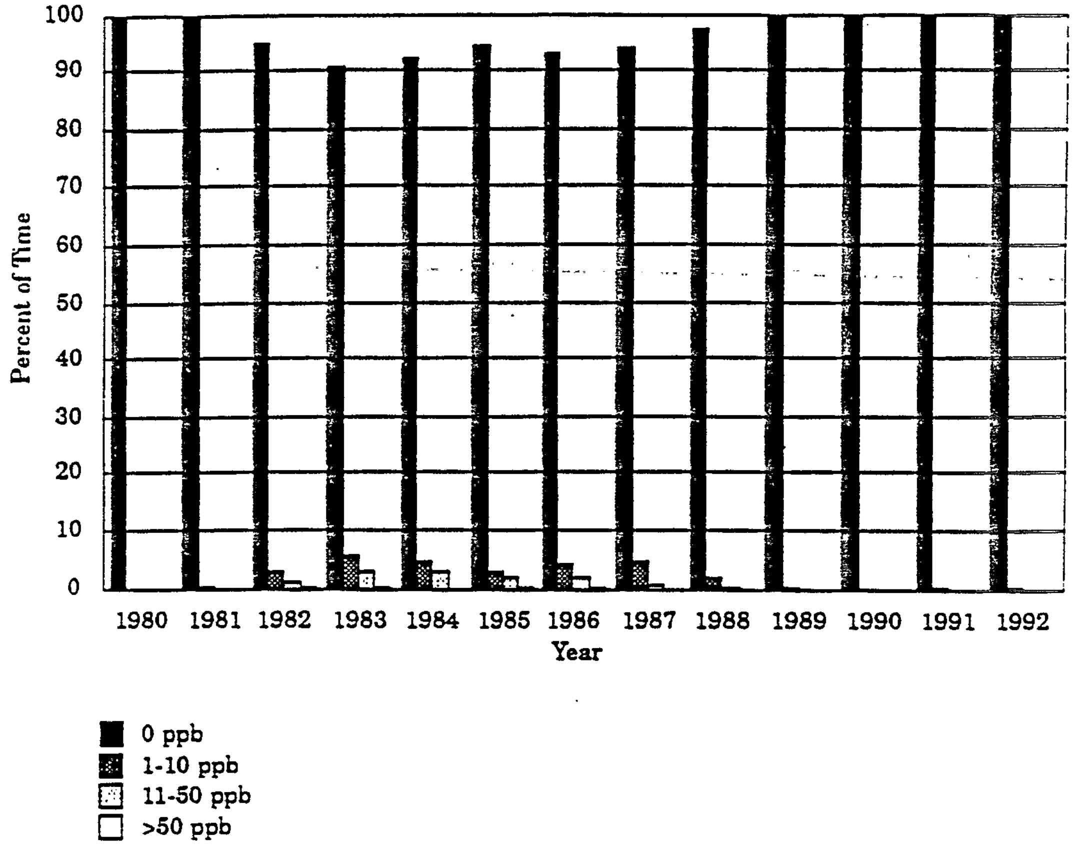
concentration of 18 ppb. The longest period of monitoring data received was from the north unit (recorded in the Little Missouri River Valley), covering the period from April 24, 1980, to August 2, 1992 (1990 data were not received by NDSDH&CL). In the early years, numerous violations of the 1/2-hour, 32 ppb NDAAQS occurred (e.g., 68 in 1982, 62 in 1983, and 70 in 1985). The maximum 1/2 hr time-weighted average concentration recorded during this period was 500 ppb in 1982. Air quality did improve during the second half of the study period, with several years of no NDAAQS violations. This was a result of NDSDH&CL mandated implementation of rigorous operations and maintenance programs by well operators involved in the field and tank vapor collection. Also, expansion of a gas-gathering pipeline network contributed to the decrease in H_2S concentrations because gases were previously released to the atmosphere.

From 1988 to 1990, the Williston Basin Regional Air Quality Study (BLM, 1990) was undertaken as a joint project between North Dakota and the Bureau of Land Management (BLM) to forecast compliance with Federal standards for sulfur dioxide, the resulting product of hydrogen sulfide combustion. Figure III-8 shows the range of concentrations measured at the site. Although over the entire period, 0 ppb was the concentration most frequently recorded, a decrease in air quality is charted, from 1982 through 1987.

Lone Butte. Lone Butte, is located approximately 11 km from the north unit of Theodore Roosevelt National Memorial Park (see Figure III-5). Lone Butte had concentrations of hydrogen sulfide an order of magnitude higher than the other sites. The monitor at Lone Butte (see Figure III-9), in the Little Missouri River Valley near an oil tank battery in the Lone Butte Oil Field, recorded more than 3000 violations of the 1/2-hour average 32 ppb NDAAQS per year from 1984 to 1986. Air quality did improve at the end of the monitoring period, although not to levels continuously below the NDAAQS of 50 ppb which was the standard at that time.

Figures III-10 depicts the range of concentrations measured at the Lone Butte site. Zero ppb is recorded more than 50 percent of the time through the early years, with an improvement towards 80 percent of the time by 1989. (The detection limit of the monitoring equipment was 1 ppb.) The improving trend toward the hydrogen sulfide standard occurred when the NDSDH&CL correlated the sources of the hydrogen sulfide with the ambient monitor levels through the use of the prevailing wind direction. The possibility of NDSDH&CL requiring individual monitoring at each well site convinced the producers to reduce their emissions (personal communication, D. Harman, NDSDH&CL, 8/11/92).

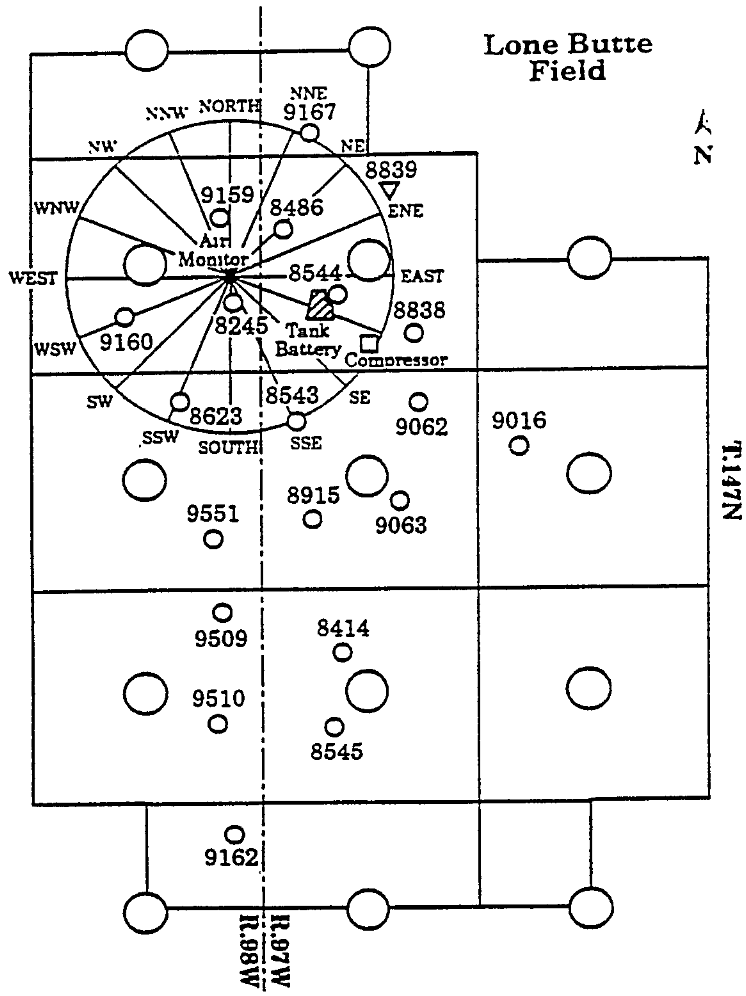
Other Monitoring Sites. Data from thirteen months of monitoring during 1989-1990 were recorded at the Olson farmyard, 1.5 miles from several wells in North Dakota. A maximum 1-hour average concentration of 88 ppb was recorded. Data were also obtained from September 4, 1990, to August 3, 1992, from a monitor in the town of Plaza, North Dakota, within 2 miles of several wells and tank batteries. The maximum concentration recorded on this monitor was 358 ppb, in 1991, with one violation of the NDAAQS recorded.



H_2S monitor detection limit = 1ppb

Source: Personal correspondence, D. Harman, NDSDH & CL, 8/11/92.

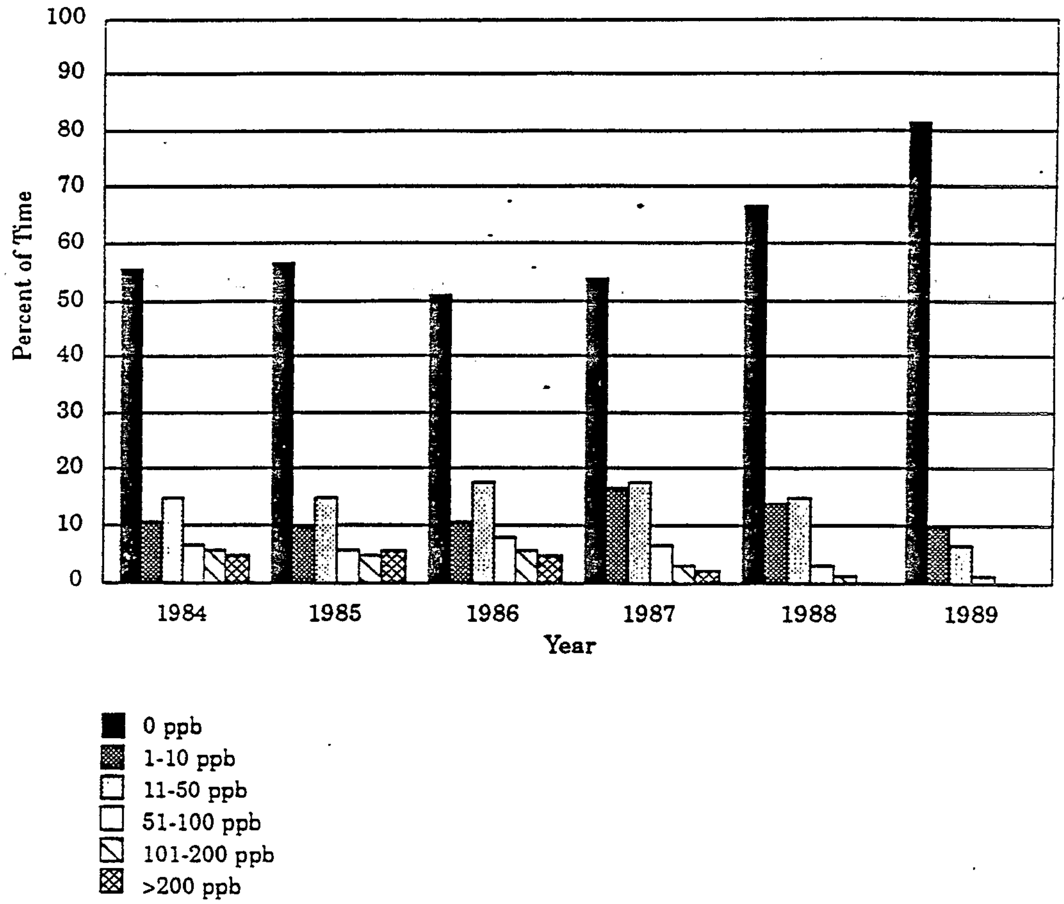
Figure III-8. Percentage of times designated H_2S concentrations were measured at the Theodore Roosevelt National Park – North Unit monitoring site.



File No.	Operator	Well Name	Well No.
8245	Chevron USA, Inc.	Bob Creek Federal Unit	1-13-3B
8414	Chevron USA, Inc.	Carus Federal	1-30-1C
8486	Apache Corp.	Federal 18	1
8543	Chevron USA, Inc.	Bob Creek Federal Unit	4-19-1D
8544	Chevron USA, Inc.	Bob Creek Federal (Comm)	2-18-48
8545	Chevron USA, Inc.	Carus Federal	2-30-4B
8623	Chevron USA, Inc.	Bob Creek Federal	3-24-2A
8838	Apache Corp.	Carus Amoco Unit "A"	1
8839	Apache Corp.	Carus Amoco Unit "C" (SWD)	1
8915	Apache Corp.	Lone Butte Federal Amoco "A"	1
9016	Apache Corp.	Carus Amoco "B"	1
9062	Apache Corp.	Lone Butte Federal Amoco "B"	1
9063	Apache Corp.	Federal	19-1-
9159	Texaco, Inc.	Bob Creek	13-8
9160	Texaco, Inc.	Bob Creek	13-11
9162	Texaco, Inc.	Bob Creek	36-1
9167	Texaco, Inc.	Bob Creek	7-13
9509	Chevron USA, Inc.	Mormon Butte	5-25-2B
9510	Chevron USA, Inc.	Mormon Butte Federal	3-25-3B
9551	Chevron USA, Inc.	Foley-Stewart Federal	4-25-3C
N/A	North Dakota State Dept. of Health	Air Monitor	
N/A	Koch Hydrocarbon	Compressor Station	
N/A	Chevron USA, Inc.	Tank Battery	

Source: Personal correspondence, D. Harman, NDSDH & CL, 8/11/92.

Figure III-9. Wells producing between July 1986 and December 1987 surrounding Lone Butte H_2S ambient air monitoring site.



H_2S monitor detection limit = 1ppb

Source: Personal correspondence, D. Harman, NDSDH & CL, 8/11/92.

Figure III-10. Percentage of times designated H_2S concentrations were measured at the Lone Butte monitoring site.

Only four months of monitoring data from the Roffler site were received by NDSDH&CL. dating from April 11, 1980, to September 29, 1980. Located in a farmyard within 1/2 mile of a well and tank battery, the monitor measured very low concentrations (usually 0 ppb) with a maximum, time-weighted average of 13 ppb recorded. In contrast, at the Jorgenson monitor, the recorded concentration was as high as 250 ppb. The Jorgenson monitor was located in a valley within one mile of several wells, and the data received dated from October 2, 1980, to May 13, 1982. Data from sixteen months of monitoring, from June 30, 1982, to October 31, 1983, were received for the Kadrmas site. Located in a farmyard within a mile of several wells, the maximum half-hour averages recorded were 541 ppb, in 1982, and 353 ppb, in 1983. From these three studies, an analysis was performed on the monitoring data in comparison to the 32 ppb half-hour standard. The results showed that the concentration of hydrogen sulfide never exceeded the NDAAQS during the four months of the Roffler study. Conversely, at the Jorgenson site, the 32 ppb standard was violated 16 times in 1980, 38 times in 1981, and 26 times in 1982. At the Kadrmas site, the violation count was 18 times in 1982 and 14 times in 1983.

Williston Basin Study. The Williston Basin Regional Air Quality Study was undertaken in the late 1980s to assess the air quality impact of oil and gas production in western North Dakota (BLM, 1990). Emissions inventories were prepared and air quality models were applied to project the impact of sulfur dioxide and hydrogen sulfide emissions in these 12 selected oil fields with respect to applicable ambient air quality standards and PSD increments. Study results suggested that exceedances of both sulfur dioxide and hydrogen sulfide ambient air quality standards could be expected for some fields. Exceedances of Class I PSD increments for sulfur dioxide were expected for three of the four Class I areas studied. Further development of the oil and gas fields, where the emissions of sulfur dioxide and hydrogen sulfide would be possible, would not be permitted unless these exceedances were addressed.

To arrive at estimated hydrogen sulfide concentrations for the study, two types of hydrogen sulfide emissions were considered. First a hydrogen sulfide concentration was obtained through back calculation of the output sulfur dioxide concentrations from the Industrial Source Complex Model. The predicted sulfur dioxide concentrations were the result of modeled dispersion of the point source emissions from heater-treaters firing on H_2S contaminated wellhead gas and from flares which burn H_2S contaminated wellhead gas when a gas gathering pipeline is not available. To provide conservative results, combustion efficiency of 75 percent was used in these calculations, meaning that 25 percent of the hydrogen sulfide remained unchanged. [Note: As stated in Chapter II, flares, in most applications, operate at 95 to 99 percent efficiency.] The second emission source used represented fugitive emissions from leaky valves, tank hatches or pipe connections. These fugitive sources were estimated as contributing a background concentration of 7 $\mu g/m^3$ (50 ppb), derived from the 99th percentile of the 1-hr average monitored ambient air concentrations at three remote monitor locations (the Theodore Roosevelt National Park's two sites and the Lostwood site) during portions of 1987 and 1988.

At the time of the study, the NDAAQS for H_2S was 50 ppb 1-hour average concentration not to be exceeded more than once a year. NDAAQS exceedances were predicted for 6 of the 12 fields studied using current emissions estimates, with exceedances predicted for 7 of the 12 fields using future emissions estimates. Of the sites where modeling suggested NDAAQS exceedances, the yearly second highest (the first occurrence of ambient hydrogen sulfide concentrations above 50 ppb would be allowed by the law) expected concentrations exceeded 700 ppb for the Lost Bridge Field and 900 ppb for the Rough Rider Field.

Modeling results are only an estimate and are often considered accurate when they are within a factor of two of the actual ambient concentrations. Except for the Lone Butte Field, ambient monitoring data were not available for the other fields to verify or contradict the modeled estimates.

Conclusions. At several locations, for example, Lostwood and the Theodore Roosevelt-south unit, the monitoring program served as a verification that the air quality was within the levels allowed by the law. In two cases, the monitoring programs were of too short of a duration to support any conclusions. When an area is monitored for a short period of time, as at the Roffler and Olson sites, the full range of meteorological conditions and emissions scenarios are not represented in the ambient air measurements. Monitoring was discontinued at Jorgenson and Kadrmas (both monitored in the early 1980s) and at Lone Butte (the site with the worst air quality) even though numerous NDAAQS violations were experienced during their last monitored year. This occurred because rigorous inspection and maintenance scheduling was established and/or the data indicated no air quality problems existed (personal communication, D. Harman, NDSDH&CL, 11/9/92).

Ambient concentrations of hydrogen sulfide varied for the sites, with maximum yearly concentrations ranging from half-hour averages, below the 1 ppb detection limit, to 2734 ppb (2.734×10^3 ppb). Two common factors were the median and mode values. For all of the monitoring data received from North Dakota, the median and mode values were 0 ppb. In other words, for each site more than half of all observations recorded below the 1 ppb monitor detection limit.

Severity of Consequences. No epidemiological studies have been carried out to assess the effects of hydrogen sulfide exposure resulting from the production of oil and gas. Many States have enacted ambient air quality standards based upon odor for hydrogen sulfide, since its odor recognition threshold is so low (i.e., 3 to 20 ppb).

Annual average H_2S concentrations, which can more appropriately be compared to a long-term concentration benchmark such as the RfC, were also calculated from the Lone Butte site. These values exceeded the RfC by about an order of magnitude from 1984-1987, dropping to about the RfC level in 1988 and 1989. Since these values indicate the combined impacts of 9 separate wells, it is reasonable to conclude that: 1) the long-term impact of routine releases from any individual well is probably not significantly greater than the RfC;

and 2) the use of a gas-collection system with manifolded flares and rigorous operation and maintenance programs can significantly reduce long-term H_2S impacts.

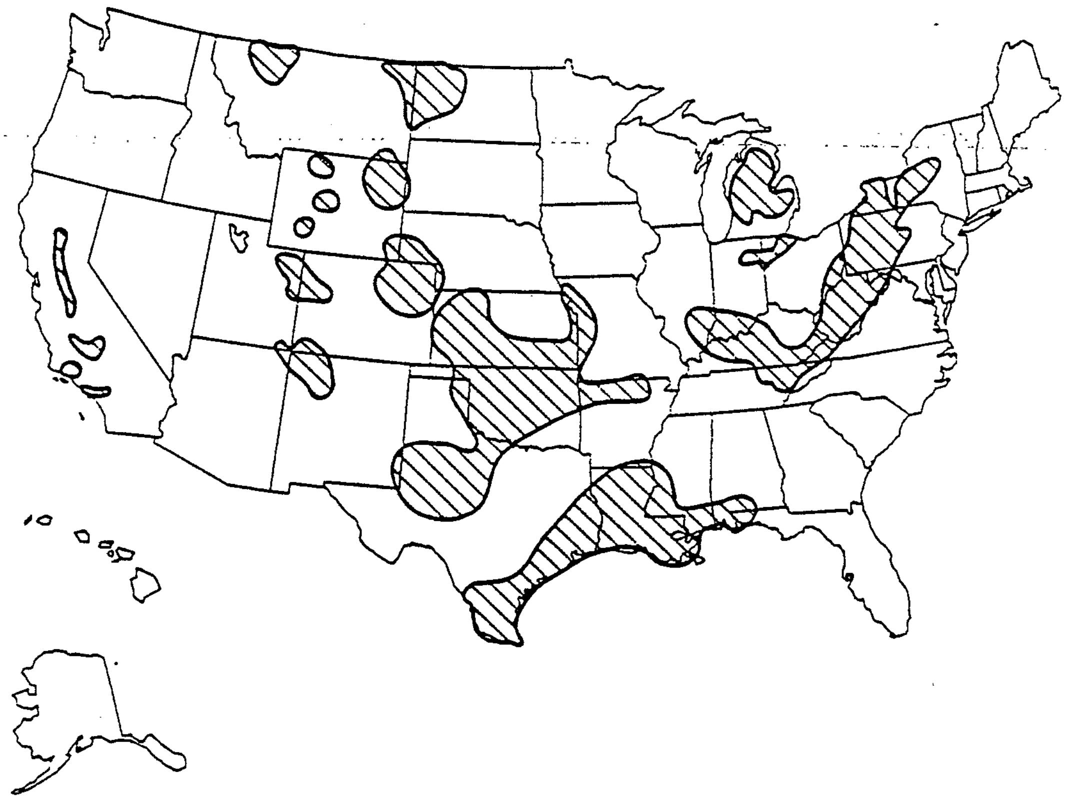
At low concentrations, odor nuisance and eye and respiratory tract irritation are the consequences of exposure rather than the toxic properties of the gas. An explanation for an increased perception of ill health could be related to low level exposure to hydrogen sulfide and pulmonary infections. A study by Rogers and Ferin (1981) concluded that hydrogen sulfide significantly affected the antibacterial system of rats by impairing pulmonary macrophage. However, additional research would be required before any definitive judgements could be made in human exposure scenarios.

Elevated ambient concentrations in two episodes (one in the Great Kanawha River Valley, WV, in 1950, and one in Terre Haute, IN, in 1964) were reported as 0.41 mg/m^3 (293 ppb) and 0.46 mg/m^3 (329 ppb), respectively (West Virginia Department of Health, 1952; U.S. Public Health Service, 1964). These incidents did not result from oil and gas production; however, the ambient concentrations recorded were comparable to some measurements in North Dakota. General symptoms of malaise, irritability, headache, insomnia, and nausea were reported by exposed populations. In the Terre Haute incident, levels measured at a nearby lagoon ranged from 2×10^3 to 8×10^3 ppb). The most common symptoms reported were offensive odor, foul-tasting water, nausea, vomiting, diarrhea, throat irritation, shortness of breath, burning eyes and asthma. Milder symptoms included cough, headache, anorexia, acute asthma attacks, nervousness, weight loss, fever, gagging and heaviness of chest. The symptoms ceased when the odor disappeared. In an episode in Alton, IL in 1973 similar symptoms were reported (Illinois Institute for Environmental Quality, 1974; NRC, 1979). Ambient hydrogen sulfide levels ranged from 25 ppb to higher than 1×10^3 ppb. Other contaminants, such as ozone and nitrogen oxides were also detected during this episode (Hoyle, 1973).

A study of the levels of sulfur compounds in vegetation near the Lone Butte oilfield and Theodore Roosevelt National Park, was conducted during the summer of 1987 (Bilderback, 1988). The study's conclusions confirmed what ambient monitoring had suggested: the South Unit of the national park may have been impacted by moderately high levels of atmospheric sulfur pollution, and the Lone Butte oil field was impacted by high levels of reactive atmospheric sulfur. Visible signs of vegetation damage were also detected at the Lone Butte oilfield. Furthermore, Bilderback attributes the elevated levels of hydrogen sulfide at the North Unit of the Park to the Lone Butte oilfield.

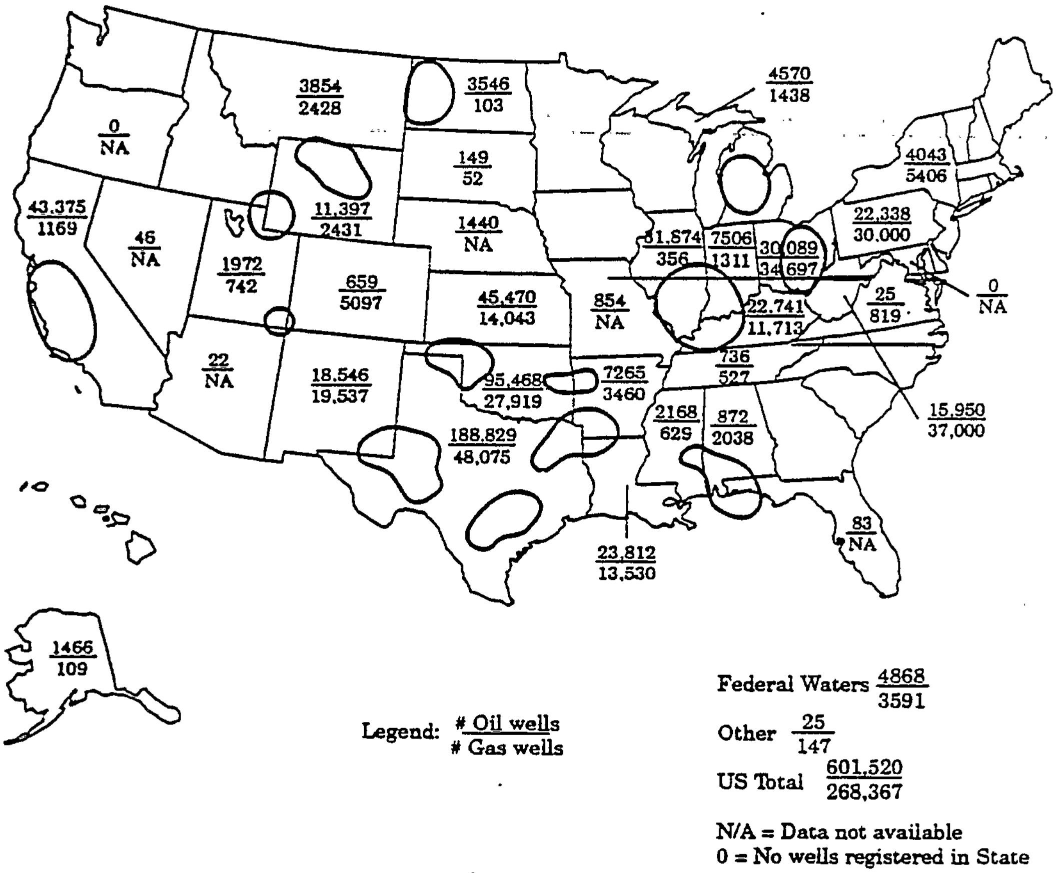
Consequence Analysis — Routine Emissions

As described in Chapter II, several potential sources of routine H_2S emissions can be found at oil and gas production facilities. Figures III-11 and III-12 indicate that 8 States have a significant overlaps of well fields and H_2S prone areas. Using the estimated number of producing wells in these States (Figure III-12) as a conservative measure, it appears that as many as 280.000 oil wells and 54,000 gas wells have the potential for location in an H_2S



Source: IOGCC, 1990.

Figure III-11. Oil and gas fields.



Source: Gas Research Institute, 1990.

Figure III-12. Major H_2S prone areas shown in relation to number of producing oil and gas wells in 1990.

prone area. Although only a fraction of these wells would actually be sour, these figures imply that the potential for routine H_2S emissions is significant. However, no national statistics are available to predict the probability of such emissions. The only record of routine emissions identified is ambient air quality monitoring data from the State of North Dakota. Nine monitoring studies in 12 years resulted in more than 3,300 violations of the NDAAQS. The majority of these violations occurred when the standard was developed based on the more conservative odor threshold rather than on health considerations. Only one violation was recorded after the health-based (higher concentration limits) standards were implemented.

A routine emission scenario would be the incomplete combustion of the wellhead gases, allowing some percentage of the hydrogen sulfide to be emitted. In the oilfields of North Dakota, the concentration of hydrogen sulfide in waste gas stream to flares can reach 30 percent, with the conversion efficiencies of the flaring operations varying from 30 to 100 percent (NDSDH&CL, 1983). (Note, however, that in Chapter II, the common efficiency of a flare, regardless of industrial application is 95-99 percent.) This scenerio would result in releases of 0 to 70 percent of the hydrogen sulfide contained in the wellhead gas. In western North Dakota, the amount of natural gas flared exceeded 1 million cubic feet per month in mid-1982, dropping to less than half of that amount by mid-1985, as more wells were tied into a central gas collection system (Liebsch, 1985). As a worst case scenario, if the gas content were 30 percent hydrogen sulfide, and the combustion efficiency were 30 percent (70 percent of the hydrogen sulfide was emitted unconverted), 210,000 cubic feet of hydrogen sulfide per month could have been routinely emitted in the mid-1982 time period.

No H_2S health or ecological effects studies have been conducted which specifically target oil and gas production. The most common consequences of exposure to routine emissions of H_2S are the odor nuisance and eye and respiratory tract irritation.

Exposure Analysis—Accidental Releases

The discussion of accidental releases begins with a description of examples of accidental releases of sour oil and gas in the United States that have impacted the public and wildlife. These examples are then supplemented by calculations of the consequences of a series of hypothetical accident scenarios using atmospheric dispersion models. The risk to the public from an accidental release of H_2S is a function of both the potential consequences and the likelihood of occurrence of an accidental release. Risks from a major accidental H_2S release will vary from facility to facility depending on site-specific factors such as the population density and distribution of nearby populations and the quality of process safety management and risk management practiced at the facility. Since risk is a product of both consequences and likelihood, risk reduction must take both into account. The accidental release discussion concludes with an assessment of accident prevention, mitigation, and emergency procedure measures that, if systematically implemented, could help to prevent or reduce the likelihood of accidental releases of H_2S from sour oil and gas, and mitigate the consequences in the event that a release occurs. Supporting details for the atmospheric dispersion calculations may be found in Appendix C.

Accidental Release Records

A variety of sources were investigated to locate documentation of accidental sour gas releases. These sources include: Congressional testimony; literature searches; database searches; state regulatory authorities; emergency response organizations; and industry officials. No national statistics regarding sour oil or gas releases were identified. Data base sources were the Accidental Release Information Program (ARIP) database which is maintained by the EPA, the Acute Hazardous Events (AHE) database which was developed by EPA, and the Emergency Response Notification System (ERNS) database. ARIP has records of chemical accidental releases that have occurred since October 1986 with some detailed information on accident cause. AHE has incident records covering the time period 1982 to 1986 and was developed from various sources including press reports, spill reports to the National Response Center, and some state and EPA regional office records. ERNS contains records of releases reported to the National Response Center.

A review of available sources revealed several documented examples of incidents in oil and gas extraction operations in the United States where accidental releases of H_2S have impacted the public and/or the environment since 1974. There was also a very large sour gas release that caused some environmental damage in Alberta, Canada during this time period. Examples of some of these accidents are summarized in Table III-4. It should be noted that these incidents include two accidents related to carbon dioxide injection to improve recovery rather than from the accidental releases of sour natural gas. One of these accidents resulted in eight fatalities, and another accident resulted in two injuries. The other incident resulting in fatalities was the result of fire associated with a natural gas release. However, effects on the public that are directly related to oil and gas extraction activities have most often been limited to evacuation. Isolated incidents resulting in hospital treatment have also occurred. Evacuation may occur as a conservative measure whether or not a life-threatening situation exists. There have been several documented incidents involving livestock and wildlife fatalities. In addition to toxicity, the flammability of accidental releases of sour oil and gas may also present a significant hazard.

Information from the State of Texas shows that there were 145 incidents of sour oil and gas release during the years 1985 through 1992 (Hall, 1992). These accidents were generally related to sour oil and gas rather than specifically from extraction activities. In these incidents, there were 10 deaths (all occupational), and 109 injuries (100 occupational and 9 public). The Texas incidents may be illustrative of the relative hazard to operating personnel, the general public, and the environment. These statistics indicate that the major hazard from oil and gas operations involving H_2S would be to workers rather than the public or wildlife. Workers are more often in close proximity to the wells and associated equipment.

Table III-4. Examples of Accidental Releases of H_2S from Oil and Gas Extraction Operations with Impact on the Public or Environment

Date and Location	Effects on Public	Effects on Environment	Comments	Source
5/21/74 Meridian, MS	5 deaths due to associated fire	40 acres burned	Sour gas gathering pipeline rupture and subsequent fire	Texas Oil and Gas Pipeline Corporation, 1976
2/2/75 Denver City, TX	8 occupants of house 200 ft from well were overcome by the gas and died.	None identified	Gas escaped from gas injection well. Gas was 93 v/o CO_2 and 5 v/o H_2S.	Layton et al., 1983
5/21/81 Big Piney, WY	No impact on public	Deaths of some jackrabbits and blackbirds	Well blowout lasting 8 days. Nearest residence was 2 miles away	Layton et al., 1983
10/7/82 Calgary, Canada	No impact on public	A number of moose and other large animals died	Release of 10 million ft^3 H_2S per day of accident	Oil Daily, 1982
/88 Lea County, NM	1 person physically incapacitated	1 horse died	An individual changing a tire was overcome with H_2S	Correspondence NM Oil Conservation Division, 1992
/20/89 Scurry County, TX	Evacuation of nearby residents, 2 treated at hospital	None identified	CO_2 injection line rupture	Texas Railroad Commision Hall, 93
/20/90 Laplata County, CO	2 mile radius evacuated	None identified	Well leak	ERNS, National Response Center Report #01425
/29/90 Heidelberg, MS	No deaths but 2,000 local residents were evacuated	None identified	Well blowout and consequent fire	Platt's Oilgram News, 1990
16/91 Lambert, MT	12 people were evacuated	None identified	Incident was caused by corrosion of gathering line. Evacuation due to smell.	National Response Center
19/91 Yoakum County, TX	None identified	7 cows, 1 coyote, and rabbits died	Sour gas gathering line rupture, 1.2% H_2S	Texas Railroad Commision Hall, 93
2/17/91 Gaines County, TX	None identified	Unspecified number of wildlife died	Sour gas gathering line rupture, approximately 6% H_2S	Texas Railroad Commision Hall, 93

Atmospheric Dispersion Analysis

Atmospheric dispersion analyses of sour oil and gas releases by computer model were both reviewed in the literature and conducted. The following issues are discussed prior to analyses of the consequences of sour gas release scenarios:

- Choice of scenarios;
- Sour gas composition and density;
- Behavior of sour gas upon release; and
- Choice of atmospheric dispersion models.

Choice of Scenarios. The objective in choosing scenarios was to investigate a representative range of potential accidental release situations including hypothetical worst case scenarios. Scenarios for atmospheric dispersion analysis were chosen from documented accidental releases, expressions of public concern, and literature analyses in which dispersion models were applied to sour gas release scenarios.

The accidental sour gas releases documented in the previous section show some common causes. Well blowouts and line releases are examples of accidents that have occurred and resulted in offsite impact. Therefore, these accident scenarios were included in the atmospheric dispersion analyses. Investigation of some public complaints resulted in concerns regarding sour gas releases from extinguished flares, collection of sour gas in low-lying areas, leakage from temporarily abandoned or idle wells, and line leakage (NDSDH&CL, 1989; U.S. EPA, 1992). These concerns were also investigated as accidental release scenarios.

Several literature sources provided descriptions of hazards associated with the operation of sour oil and gas wells in addition to sour gas dispersion analysis to support scenario development. Hazard/risk analyses and data on the composition of sour gas of wells in Alberta, Canada (Alp et al., 1990), southwest Wyoming and northern Utah (Quest, 1992), and western Wyoming and adjoining areas of Utah and Idaho (Layton et al., 1983) were considered in the choice of scenarios. Assessments of levels of concern (LOC), concentrations at which H_2S is of concern, for acute exposure to H_2S were also provided in these sources. Although H_2S alone is more dense than air, in general, the literature pertains to sour gas mixtures that are typically less dense than air and concludes that sour gas releases from well blowouts and line ruptures are of most concern as potential causes for levels of concern to extend significant distances from the point of release.

Sour Gas Composition and Density. The density of sour gas mixtures is of importance because it is one determinant of whether an accidental release will result in a plume that travels downwind at ground level or will result in a buoyant plume that rises and disperses. A dense plume may have a greater impact on humans and wildlife because it remains at ground level for a period of time. The density of sour gas mixtures at atmospheric pressure (to which accidental releases of sour gas are discharged) is dependent on the temperature and composition of the mixture. The density of a given gas mixture increases as temperature decreases. Expansion of natural gas released from a pressurized system results in cooling of the gas. The colder a gas, the higher its density.

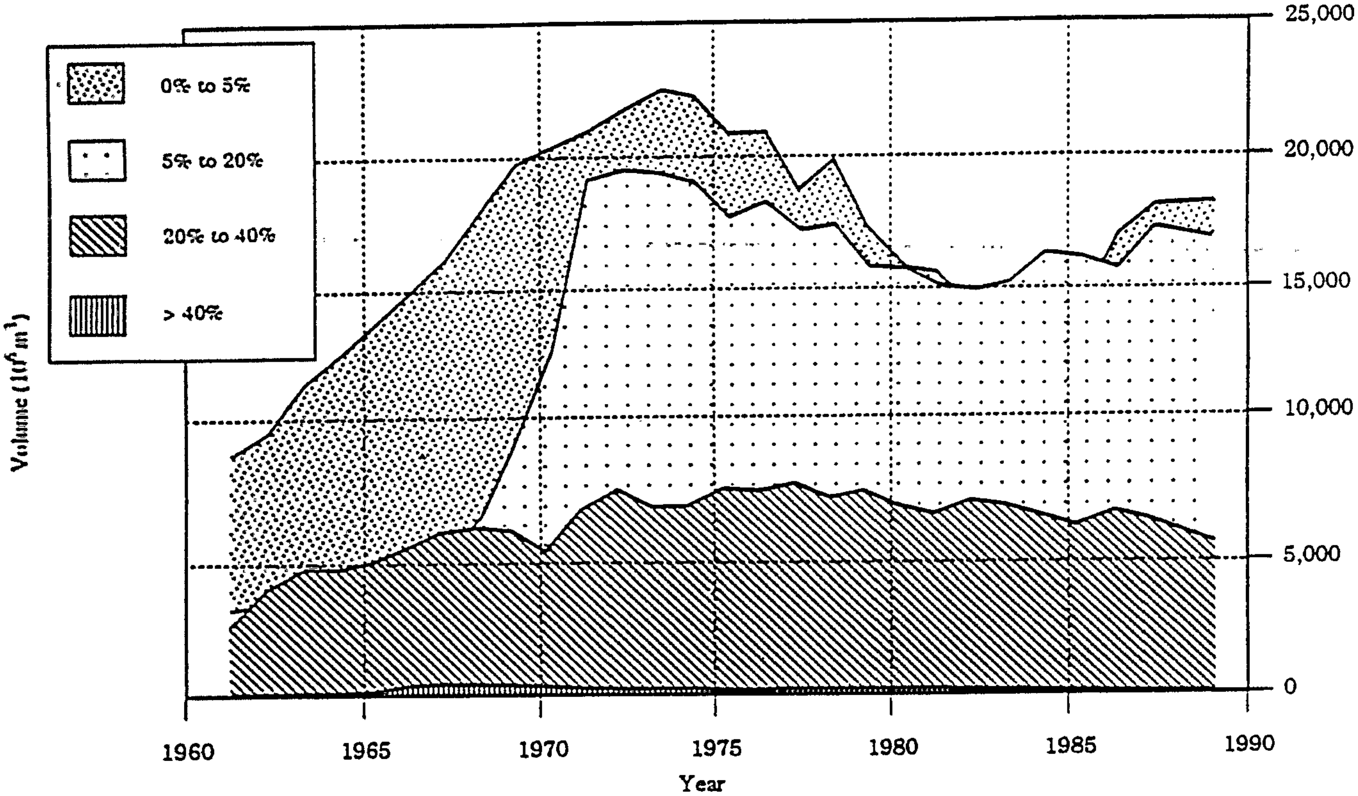
There is a wide variety of potential compositions of sour gas mixtures, depending on the reservoir. The density of these mixtures depends on their composition. In addition to hydrogen sulfide, natural gas can also contain some or all of the following: hydrogen, helium, carbon dioxide, nitrogen, methane, ethane, propane, isobutane, n-butane, isopentane, n-pentane, hexanes, heptanes, and higher molecular weight hydrocarbons. The largest component is typically methane, with hydrogen sulfide, ethane and possibly carbon dioxide (CO_2) likely to be present in significant proportions. Natural gas must contain some proportion of hydrogen sulfide in order to be considered sour.

Figure III-13 illustrates the variability of sour gas composition by showing the distribution of H_2S composition by number of sour gas wells in Alberta, Canada (Alp et al., 1990). Figure III-14 presents the same information as a function of the total number of tons of sulfur from natural gas produced each year. The H_2S composition can range from a small fraction of a percent to over 40 percent. A statistical analysis was performed of the sulfur composition of wells in the Overthrust Belt in western Wyoming and adjoining areas of Idaho and Utah (Layton et al., 1983). Volume percentages of sulfur were found similar to those in the Alberta wells. The sulfur composition ranged from less than 1 percent through 35 percent, with a mean of about 10 percent. Data on H_2S in California oil and gas fields shows fields with H_2S concentrations varying from less than 1 x 10^5 ppb (0.01 percent) to 20 - 30 percent (Dosch and Hodgson, 1986).

In addition to increasing the density of a sour gas mixture, carbon dioxide in sufficiently large concentrations can extinguish sour gas flares, resulting in uncombusted H_2S being released. CO_2 concentrations in various parts of the Overthrust Belt were found to vary from less than 5 percent by volume to more than 50 percent (Layton et al., 1983).

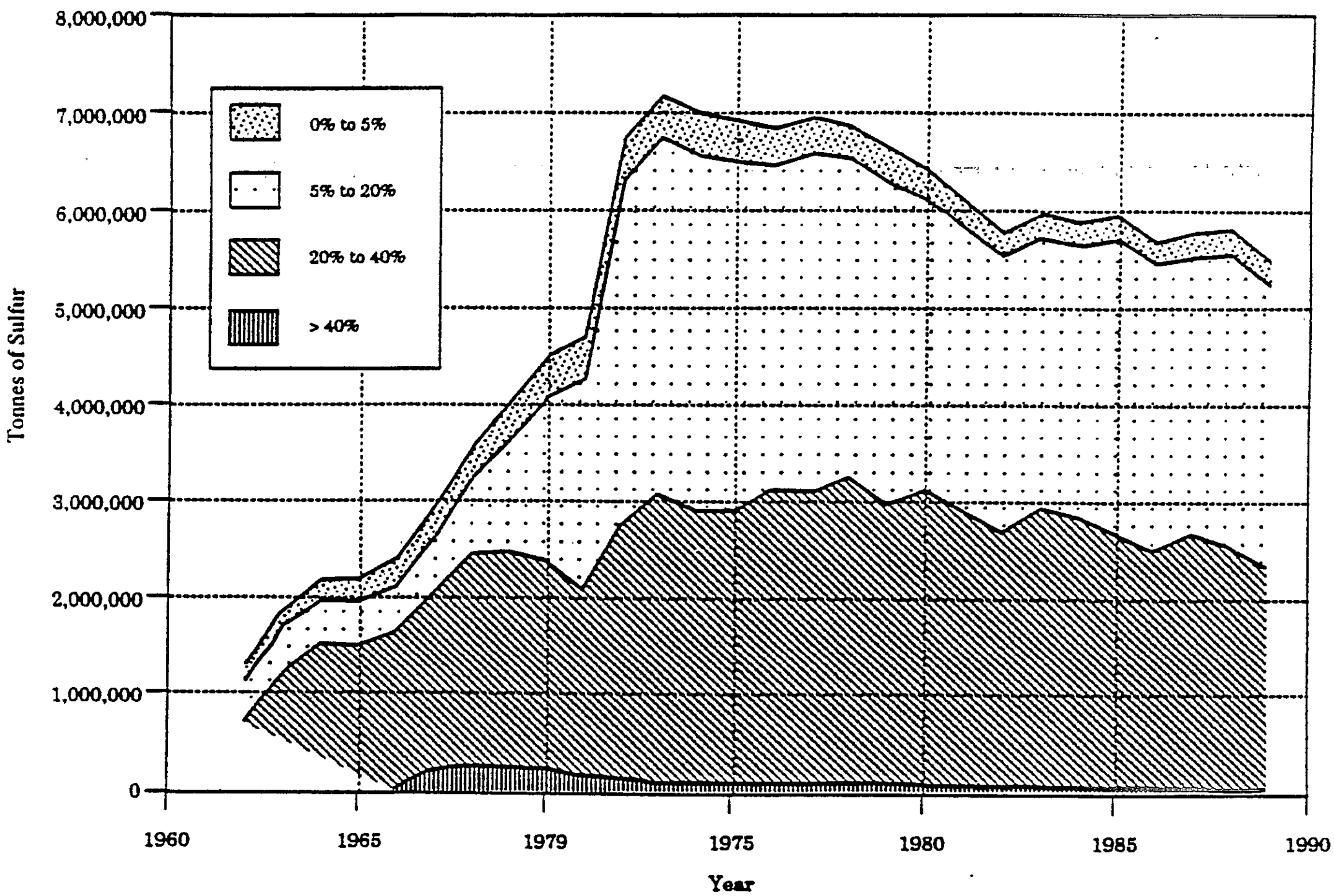
Some example sour gas compositions are presented in Table III-5.. Composition D is the single composition considered representative of all the data on producing gas wells in Alberta, Canada. Composition C is a representative gas composition produced by wells in a southwestern Wyoming sour gas field (Quest, 1992). Data were collected for a producing well in western North Dakota (U.S. EPA correspondence, 26 October 1992), and the compositions of streams after processing to recover hydrocarbon condensate at that well are given by compositions A and B of Table III-5. Composition A shows the gas composition after high pressure separation, and Composition B shows the composition after low pressure separation. The low pressure stream has a significantly higher H_2S concentration than the high pressure stream although its flowrate is lower.

H_2S alone is more dense than air, while methane alone is less dense than air. Natural gas mixtures of H_2S and light hydrocarbons are typically less dense than air to the extent that methane predominates in the mixture. The approximate molecular weight of air is 29. The



Source: Alp et al., 1990

Figure III-13. Distribution of producing sour gas wells in Alberta by H_2S content.



Source: Alp et al., 1990.

Figure III-14. Total sulfur generated from producing gas wells in Alberta by H_2S composition of well.

ble III-5. Example Gas Stream Compositions

Component	Molecular Weight	Mole Fraction: Sample Well: High Pressure (A) (well flow)	Low Pressure (B) (vapor recovery systems)	Composition Used in Cave Creek Risk Assessment (C)	Composition Used by ECRB (D)
drogen Sulfide (H_2S)	34	0.075	0.277	0.146	0.30
rbon Dioxide (CO_2)	44	0.01	0.013	0.027	0.123
rogen (N_2)	28	0.003	-	0.017	0.02
thane (CH_4)	16	0.83	0.45	0.699	0.55
nane (C_2H_6)	30	0.047	0.10	0.058	0.005
opane (C_3H_8)	44	0.012	0.064	0.018	0.001
utane (C_4H_{10})	58	0.0032	0.024	0.0042	0.001
Butane (C_4H_{10})	58	0.0038	0.026	0.0050	—
entane (C_5H_{12})	72	0.0016	0.011	0.0022	—
Pentane (C_5H_{12})	72	0.0020	0.0086	0.0018	—
xanes (C_6H_{14})	86 }	0.0034	0.019	0.0031	
ptanes+ (C_7H_{16})	100+ }			0.0176	
erage Molecular Weight		19.25	28.9	23.2	25.2

two composite compositions and the high pressure stream shown in Table III-5 have molecular weights less than 29. Thus, these streams are less dense than air at the same temperature and pressure. CO_2 is also more dense than air at similar conditions and may cause the density of a gas mixture to be higher than that of air if present in large concentrations. The low pressure stream has a molecular weight very close to that of air and with some modification in composition, such as more H_2S or CO_2 and less methane, could be more dense than air.

Gas mixtures which are denser than air due to high concentrations of CO_2 have caused fatalities as described in the discussion of release histories. A well blowout near Big Piney, Wyoming, on June 21, 1981, killed small animals up to about 0.8 km from the well (Alp et al., 1990) The gaseous emissions from the well were composed of 70 percent CO_2, 20 percent methane and 3 to 4 percent H_2S. It is not clear that H_2S caused the animal fatalities in this case. However, these emissions were clearly denser than air. The literature generally describes mixtures that are less dense than air; the studies of hazards/risks associated with sour gas (Alp et al., 1990; Quest, 1992) referred to in this report used gas compositions that are buoyant.

In conclusion, sour gas as produced is typically buoyant. There can be atypical cases where natural gas contains high concentrations of H_2S and/or CO_2 which results in a denser-than-air mixture. Also, gas processing such as separation for condensate (liquid hydrocarbon) recovery at the well site may affect the density of a gas stream.

<u>Behavior of Sour Gas Upon Release</u>. High pressure sour gas releases from well blowouts and line ruptures are initially high momentum jets which can vary directionally between the extremes of vertical and horizontal. The jet (high velocity) nature of such releases is caused by the differential pressure between the contained gas and the atmosphere and results in entrainment of the surrounding air into the released gas. Entrainment of air results in dilution of the released gas and causes its density to approach that of air. Thus, as air is entrained, both positively and negatively buoyant gas mixtures with air will tend to have densities approaching that of air. A high velocity jet (such as from a high pressure source) will entrain air more rapidly and to a greater extent than a low velocity jet from a low pressure source. Depending on the release conditions, it is possible for a gas mixture to retain its initial positive or negative buoyancy. Negative buoyancy releases are of greatest concern because of dense gas behavior and their tendency to travel to ground level where exposure is likely to occur.

As previously discussed, the effective molecular weight (and thus, the density) of sour gas mixtures as produced is generally less than that of air with isolated exceptions. Therefore, models for these cases should consider the various mechanisms that describe the near-field (near the point of release) and far-field (downwind) behavior of the plume of released gas and its interaction with the surrounding air. In particular, the models should contain mechanisms for simulation of the following sequence of effects occurring along a plume of released gas from the point of release: a) near-field momentum jet modeling; b) subsequent positively-buoyant rise or negatively-buoyant sinking; c) potential for a nominally buoyant plume that is initially on the ground to rise or, if negatively-buoyant, to stay at ground level; and d) far-field transition to a subsequent Gaussian (passive modeling) phase. The Gaussian or passive phase assumes random mixing in the far-field due to the action of atmospheric turbulence; whereas, close to the source, entrainment of air is affected or sometimes dominated by the released material itself.

Choice of Atmospheric Dispersion Models. The models reviewed in the literature for analysis of the dispersion characteristics of sour gas were GASCON2, FOCUS, and a Gaussian dispersion model. Confirmatory, independent atmospheric dispersion analyses were conducted for most of the scenarios with the SAPLUME, SLAB, and DEGADIS models.

The computer model GASCON2 was specifically developed in Canada to model sour gas releases from well blowouts and line ruptures (Alp et al., 1990). The model incorporates high pressure gas jet releases, plume rise or sinking (depending on density) and subsequent passive atmospheric dispersion. GASCON2 was validated by comparison with experiment. The associated literature also contains extensive discussions on uncertainties and the work was reviewed by a science advisory board.

The proprietary model, FOCUS, contains a treatment of momentum and buoyancy effects and transition to subsequent passive atmospheric dispersion (Quest, 1992). The model has been available for several years and has been used in a number of risk assessments of toxic and flammable vapors.

The Gaussian dispersion model is suitable for passive releases (Layton et al., 1983). Therefore, jet momentum effects are neglected and the results are not expected to be reliable close to the emission source. However, at large distances where low concentrations of H_2S would result (e.g., in the low part per million range), all three of the above models should converge to similar results.

A well-established model developed by Ooms (1974, 1983) for jet releases of vapors can model the dispersion of both buoyant and heavier-than-air momentum jets. The EPA has sponsored the incorporation of the Ooms model into the well-known DEGADIS model (Spicer, 1988), which can only simulate vertical, but not horizontal releases. Another proprietary model, SAPLUME, is also based on the Ooms model and can simulate jets at any orientation (SAIC, 1990).

SLAB was developed by Lawrence Livermore National Laboratory (Ermak, 1989). This computer model also accepts jets of vertical or horizontal orientation. However, it was specifically developed for heavy vapors and has not been carefully validated for use with buoyant plumes, so results must be interpreted with care.

Consequence Analysis — Accidental Releases

In the following sections, the consequences of accidental releases for a variety of scenarios are presented.

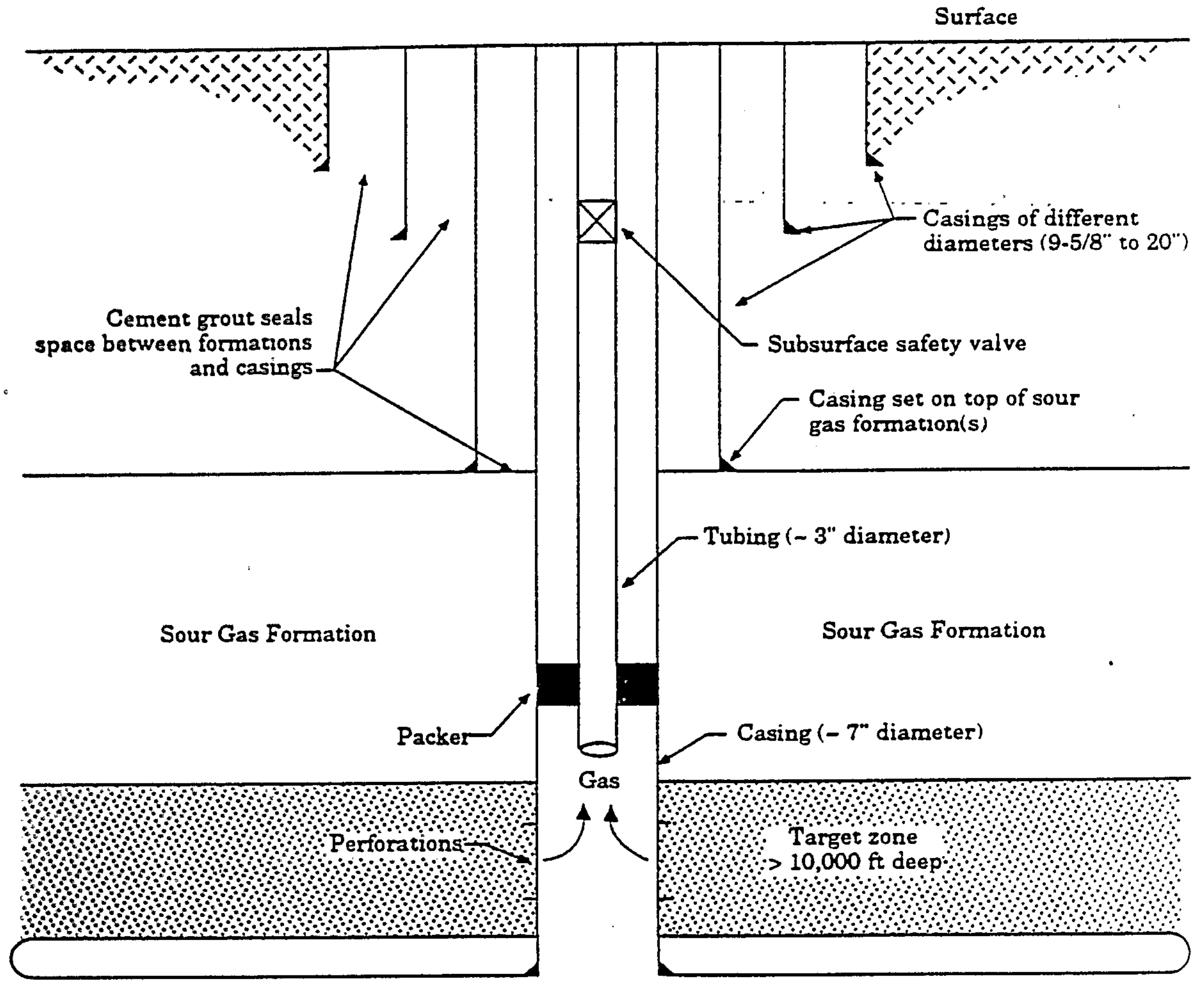
It should be noted that the calculated consequences of some of the modeled scenarios are based on very conservative assumptions in order to examine the worst case. The worst-case scenario is designed to generate the maximum impact off-site. It is considered to be extremely unlikely and does not take into account a variety of factors that can significantly reduce downwind impacts. However, the worst-case scenario is useful to facilities and communities surrounding facilities in gaining an understanding of the potential magnitude of severe situations. The potential for severe consequences should be taken into account along with more probable scenarios when setting priorities for community emergency planning.

Consequence Analysis of Jets from Well Blowouts

Figure III-15 shows the layout of a typical completed sour gas well. A well blowout is an uncontrolled release from a well during drilling, servicing, or production operations. Such an accident could occur if a blowout preventer failed during drilling or a subsurface safety valve fails to operate during production. The possible types of flow from a ruptured well are shown in Figure III-16. A useful simplification is that an accidental release into the casing is possible during drilling or servicing, while flow would likely be restricted to the production tube if there were a blowout during normal production operations. Potential flow orientations are shown on Figure III-17. Examples evaluated for the purposes of this study included the extremes of a vertical jet and a horizontal downwind jet.

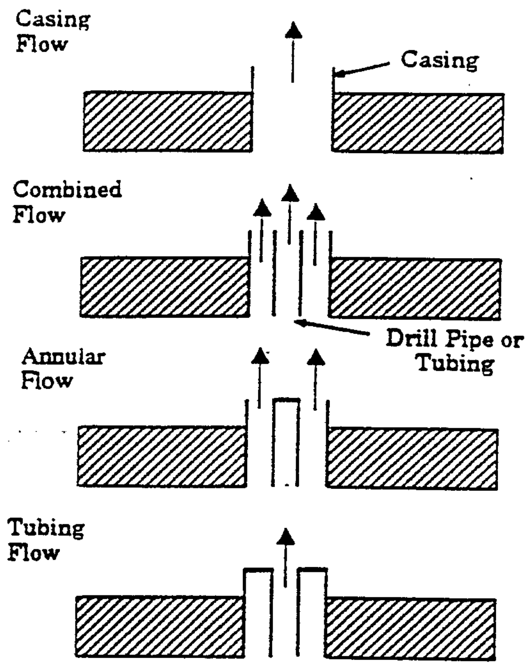
Flow rates for the scenarios identified in Figure III-16 are functions of such items as rock permeabilities, gas properties, depth, and tubing and casing diameters. Overall, there are large variabilities in these parameters. One measure of the potential rate of flow from a well is the Calculated Absolute Open Flow Rate (CAOF), which is the rate of flow of gas into the well bore when the pressure is atmospheric. This measure represents a maximum possible flow rate. The actual flow rates out of a ruptured well will be less than the CAOF because of frictional effects in the pipework. Thus, the use of CAOF for a release rate is conservative. Table III-6 gives some representative examples of how the CAOF is reduced for a specific set of well parameters. A flow rate of 2×10^7 standard cubic feet per day (scf/d) was chosen for representative calculations, with a flow rate of 10^8 scf/d being taken as an example of a very high flow rate. The bases for these assumptions are presented in Appendix C.

For the scenarios analyzed for this report, it was assumed that the gas emerges as a vapor. Since typical pressures are very high (e.g., in excess of 1,000 pounds per square inch gauge (psig)), the flow is choked (limited) at sonic velocity.



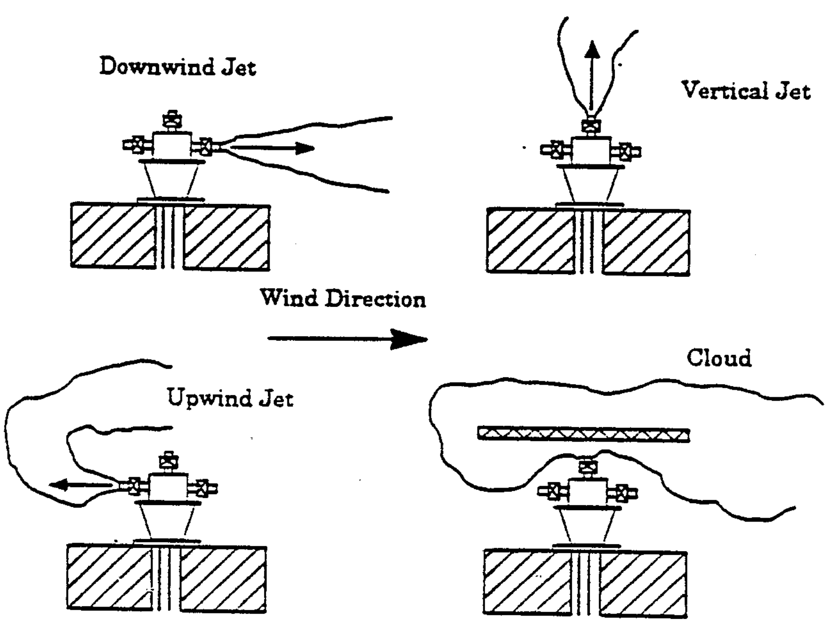
Source: Layton et al., 1983.

Figure III-15. Simplified representation of a completed sour-gas well.



Source: Alp et al., 1990.

Figure III-16. Possible well flow scenarios.



Source: Alp et al., 1990.

Figure III-17. Possible well accidental release geometries.

Table III-6. Surface Deliverability as a Function of Well CAOF

CAOF (10^3 m^3/d)*	Casing Flow	Annulus and Tubing Flow	Annulus Flow	Tubing Flow
5000	57.4 %	52.2%	39.3%	8.5%
1000	95.0	82.5	76.0	26.0
500	98.0	96.0	92.0	46.0
100	99.0	98.0	97.0	90.0
50	99.2	99.2	99.2	98.6

Source: Alp et al., 1990.

* At 15°C and 101.3kPa.

The values in Table III-7 were based on the following well conditions:

- Well depth (m) 2660
- Casing inside diameter (mm) 156.3
- Tubing outside diameter (mm) 73.0
- Tubing inside diameter (mm) 62.0
- Reservoir pressure (kPa) 15,900
- Reservoir temperature (°C) 75

The temperature of the gas in the well prior to expansion to atmospheric pressure through the rupture depends on the depth of the gas reservoir. The amount of cooling depends on the initial pressure and the composition. For the purposes of this analysis, an expanded gas temperature of 0°C (32°F) was assumed. This assumption is further discussed in Appendix C.

For a well blowout, the release could continue indefinitely. For illustrative purposes, it was assumed that any nearby individuals could be evacuated within one hour. The calculations of distances of concern discussed below assume that the duration of release and possible duration of exposure is one hour.

For vertical releases of sour gas from well blowouts, the independent dispersion modeling (SLAB, DEGADIS, SAPLUME, and the Gaussian model) and results reported in the literature (Alp et al., 1990; Quest, 1992) indicate that there will be no concentrations above levels of concern at ground level, either at the emergency countermeasure (ERPG-2) or potential fatality (LC_{01}) level. The jet is oriented upwards and, for either buoyant or negatively buoyant sour gas, dilutes rapidly due to its high momentum.

For horizontal releases from well blowouts, results calculated using the SLAB and SAPLUME models are given in Table III-7 for low wind speed and stable conditions. Releases in the direction of the wind were assumed. Depending on composition, release rate, and the model used, distances to the LC_{01} range from 700 meters (approximately 0.4 miles) to greater than 10 kilometers (approximately 6 miles). Distances to the ERPG-2 range from 2.8 kilometers (approximately 1.7 miles) to greater than 10 kilometers (approximately 6 miles). The atmospheric conditions input into the models represent conditions of high stability and little atmospheric mixing. Thus, these conditions represent the "worst-case" because levels of concern will be exceeded for predicted distances from the point of release that will exceed those for other weather conditions. The results were calculated neglecting the possibility of slight buoyancy of the plume even after dilution. DEGADIS results are not quoted because the jet module of that computer model can only handle vertical releases. For all the models, results in the range greater than 10 km (6 miles) should be regarded as beyond the limit of validity and probably conservative (see below).

For comparison, the GASCON2 model calculates an estimated distance of 1.6 km (1 mile) to the LC_{01} for a composition D flow rate of 2.4×10^5 m^3/d (cubic meters per day), or 8.5×10^6 scf/d, and an estimated distance of approximately 5 km (3 miles) for a composition D flow rate of 9.5×10^5 m^3/d (3.4×10^7 scf/d)(Alp et al., 1990). From Table III-7, for composition D with a flowrate of 6×10^5 m^3/d (2.1×10^7 scf/d), SLAB and SAPLUME predict a distance of 2.9 km and 3 km (both approximately 1.8 miles) to the LC_{01}, respectively. These distances and release rates are intermediate to those values in the GASCON2 model. Therefore, the results calculated with GASCON2 are consistent with the results generated by SLAB and SAPLUME (to within the uncertainties expected in such models).

Table III-7. SLAB and SAPLUME Results – Horizontal Releases from a Well Blowout

Composition (from Table III-6) and Flow Rates (m^3/d)	Predicted Distance 1 h Exposure (SLAB)		Predicted Distance 1 h Exposure (SAPLUME)	
	LC_{01}	ERPG-2	LC_{01}	ERPG-2
A, 6×10^5 m^3/d (7.5% H_2S)	700 m	2.8 km	1 km	3.1 km
B, 6×10^5 m^3/d (27% H_2S)	2.8 km	7 km	2.7 km	10 km
C, 6×10^5 m^3/d (15% H_2S)	1.5 km	4.7 km	1.5 km	5.7 km
D, 6×10^5 m^3/d (30% H_2S)	2.9 km	7 km	3 km	10 km
D, 3×10^6 m^3/d (30% H_2S) (extreme case)	7 km	>10 km	>10 km	>10 km

By contrast, the FOCUS model calculates an estimated distance of 0.7 km to the LC_{01} for composition C with a flow rate of $6x10^5$ m^3/d ($2.1x10^7$ scf/d)(Quest, 1992). This prediction is about half that given by the SLAB and SAPLUME calculations, which predict a distance of 1.5 km (0.9 miles) to the LC_{01} for composition C with a flowrate of $6x10^5$ m^3/d (by implication, GASCON2 would predict similar distances). This difference in predictions may lie within the range of uncertainty of vapor dispersion models; the precise reason for the difference cannot be determined from the information available about the proprietary model FOCUS.

Figure III-18 shows the results of the comparison of observations from actual well blowouts in Alberta, Canada, with GASCON2 predictions. The actual blowouts were at Lodgepole (October 17 through December 23, 1982), Clovesholm (September 24-28, 1984) and Rainbow Lake (December 9-14, 1985). The air quality data associated with each blowout were collected with public safety interests in mind and not model verification or validation. As a consequence, most of the observations were poorly documented with respect to magnitude, location, averaging time and meteorological conditions. Screening of the data to select only measurements in which there could be reasonable confidence produced a data set of 50 (45 of which were from the Lodgepole blowout). For the Lodgepole case, seven stationary and five mobile units collected data within 50 km of the site.

As can be seen, GASCON2 significantly overpredicts, especially when its predicted concentrations are in the greater than 3×10^4 ppb range, where overpredictions are by as much as a factor of 10. This concentration is the range of interest for ERPG-2 and LC_{01}. These overpredictions tentatively (because of the poor quality of the data) suggest that the GASCON2 results are conservative and, by implication, that the results from the SLAB and SAPLUME calculations are also conservative.

Possible reasons for conservatism include underestimating the effect of the plume lifting off the ground. For distances in the several km to the greater than 10 km (6 mile) range, neglect of dry deposition (fallout, transfer from the air to other surfaces) of the highly reactive H_2S may also lead to overestimation of airborne concentrations. However, it is more likely that the poor quality of the observations is reponsible for the apparent disagreements.

Standard text-book calculations indicate that flammable mixtures will not propagate more than 100 m from the point of release (Quest, 1992). If ignition occurs, potentially fatal thermal radiation loads could be received up to approximately 100 meters from the source. Although not pertinent to a discussion of hazards from H_2S releases, it should be noted that SO_2 will be emitted as a result of igniting a sour gas stream and may present a toxicity hazard.

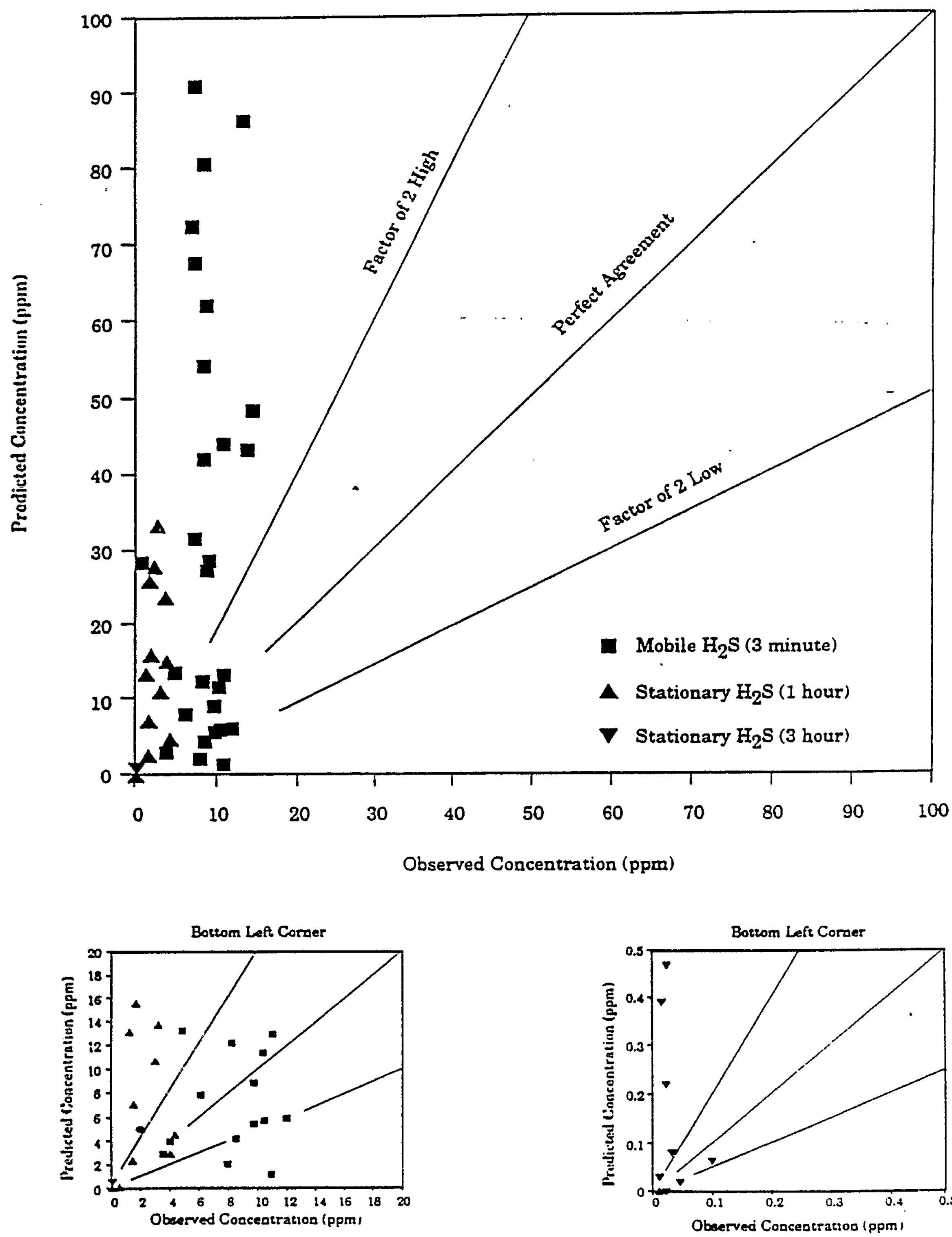


Figure III-18. Predicted H_2S and SO_2 concentrations for selected well blowout observations.

Consequence Analysis of Line Ruptures

Releases from line ruptures will behave much like well blowouts unless there is a means to isolate the rupture. Most gathering systems are not equipped with isolation systems, and aging pipework presents integrity concerns (particularly when not properly maintained). Advanced gathering line systems may have emergency shutdown valves (ESDs) that are remotely or locally operated. ESDs may be manually or automatically operated (e.g., by a signal from an H_2S detector). Figures III-19 and III-20 show some typical configurations for ruptures of lines that are equipped with ESDs. For such releases, the total mass released is limited by the quantity of gas between ESDs. The valves may be 1 km to 3 km apart (0.6 mile to 1.8 mile) (Alp et al., 1990).

Figure III-21 shows typical mass release rates for the rupture cases identified in Figure III-20, assuming a 6" diameter pipe at a pressure of approximately 5,000 kPa (725 psi). Rupture Scenario 4 (no ESD) follows Scenario 1 until a steady state of $2.4x10^5$ m^3/d ($8.5x10^6$ scf/d) is reached after about a minute.

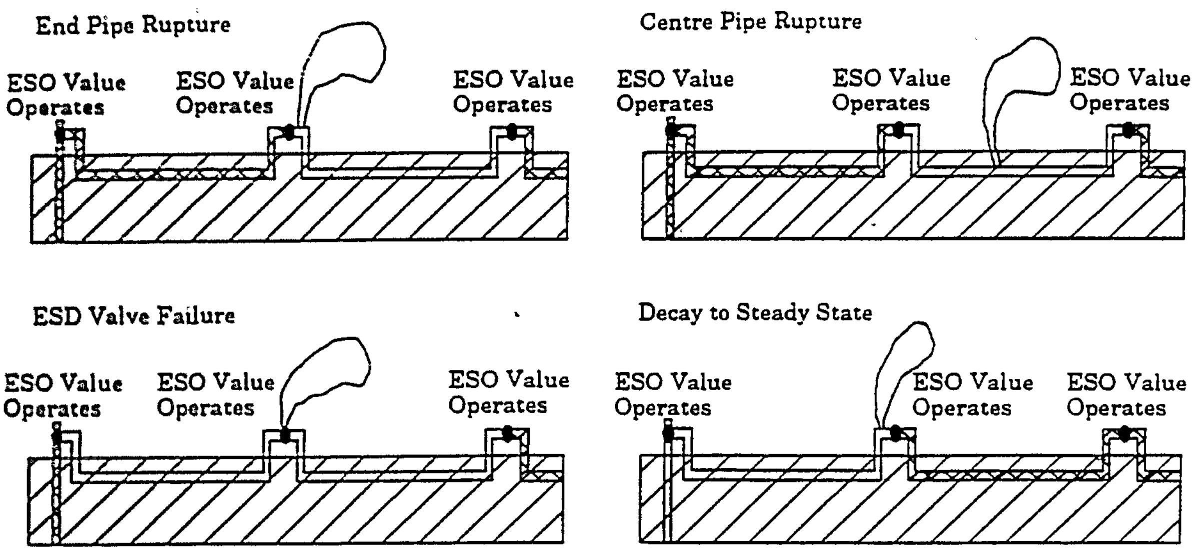
Figure III-22 shows mass release rates as a function of time for various pipe diameters and various ESD separations with an assumed line pressure of approximately 50 atmospheres (735 psi). The variable, t_d, listed on Figure III-22 is the time in seconds taken for 99 percent of the line contents to be depleted after closure of the ESD valves. M_d is the total mass released in kg. As can be seen, for many of the cases, a puff release (rather than a continuous release) is a reasonable approximation because of the short duration.

The predicted distances of concern for lines with ESD valves that close promptly are smaller than those for wellhead blowouts because the duration of release is shorter, the total mass released is smaller, and because shorter exposure times allow higher tolerable levels of concern.

Calculations from SADENZ, a companion model to SAPLUME for puff releases, predict that distances to the LC_{01} for compositions A-D in Table III-5 and released masses specified in Figure III-22 range from 600 m (0.4 miles) to 4.3 km (2.6 miles). Predicted distances to the ERPG-2 adjusted for shorter exposure time (method described by Gephart and Moses, 1989) range from 750 m (0.45 miles) to approximately 5.6 km (3.4 miles). This is consistent with the calculated results from the GASCON2 model (Alp et al., 1990) and, as before, somewhat higher than those calculated from the FOCUS model (Quest, 1992).

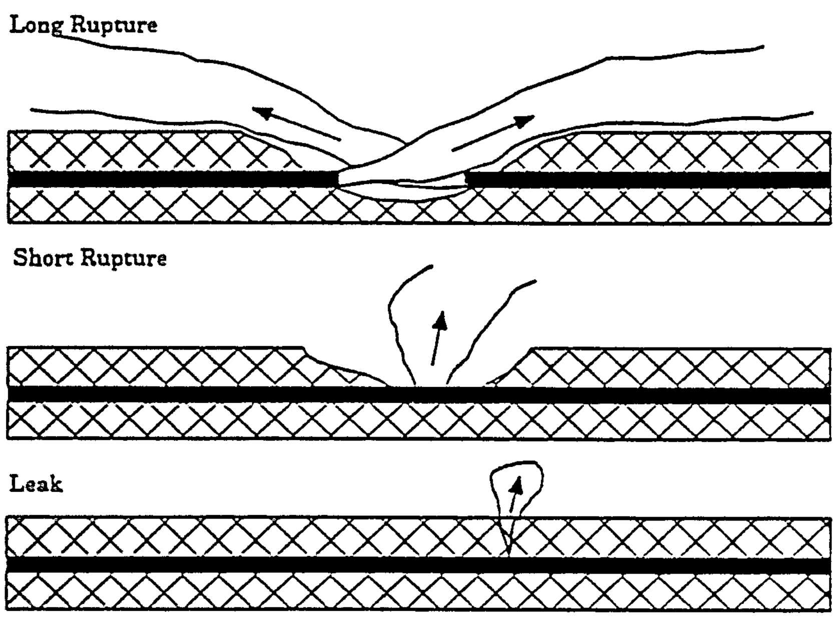
Consequence Analysis of Line Release Seepage

A survey of several gas pipeline incidents that were investigated by the National Transportation Safety Board (NTSB) indicated that, for buried gas pipelines operating above 600 psig, a 1" diameter hole will blow away the soil above the line (Quest, 1992). This will result in the formation of a crater from which the gas will escape as an unobstructed jet. For smaller holes (e.g., a 1/4" diameter hole caused by corrosion), the soil remains in place



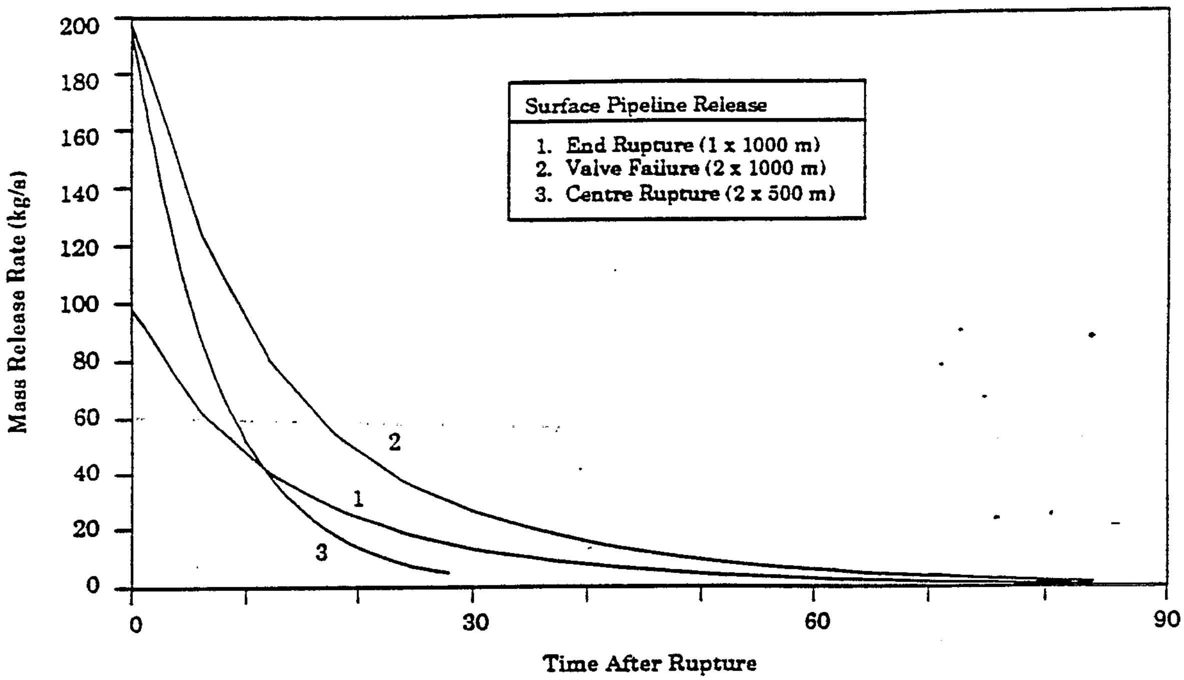
Source: Alp et al., 1990.

Figure III-19. Possible pipeline rupture scenarios.



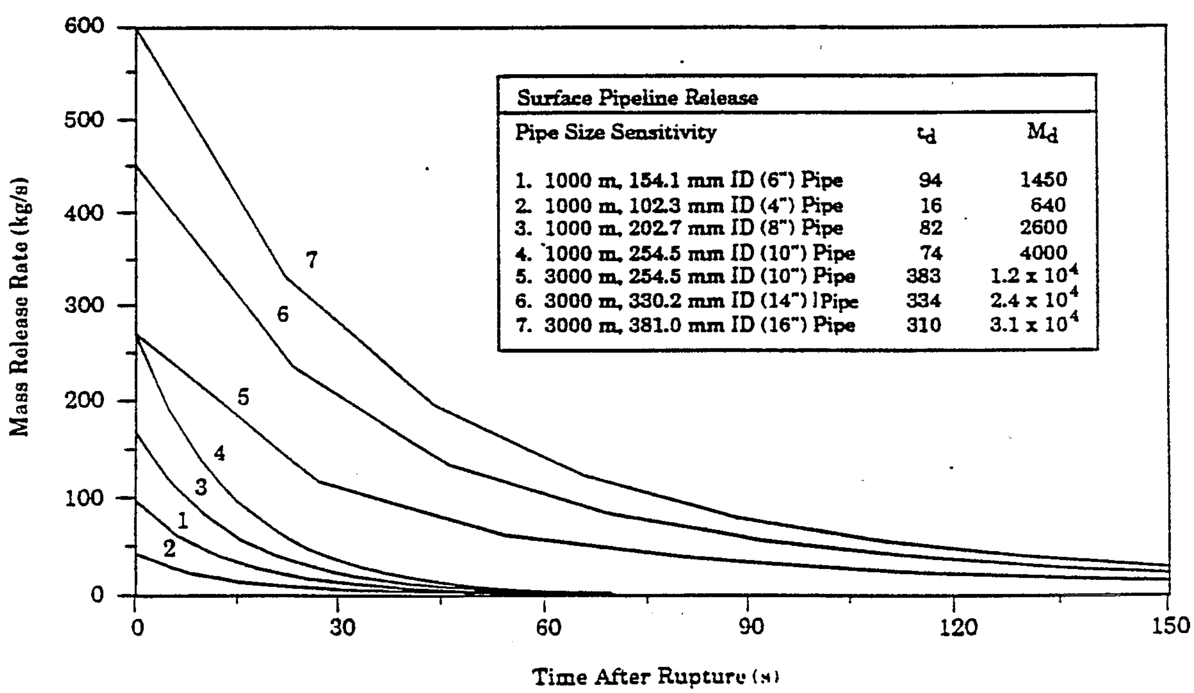
Source: Alp et al., 1990.

Figure III-20. Possible pipeline release geometries.



Source: Alp et al., 1990.

Figure III-21. Predicted mass release rates - rupture of 6" pipe.



Source: Alp et al., 1990.

Figure III-22. Predicted mass release rates - rupture of pipes of differing diameters.

and the vapors migrate to the surface where they are released without any momentum (although the resulting vapor cloud may still be buoyant enough to lift off).

For a 1/4" diameter hole in a line containing gas at a pressure of 1,000 psig, the calculated release rate (using standard text book formulae for choked flow) is about 1 lb/sec, assuming that the surrounding soil does not reduce the emission rate by physically impeding the flow. If this gas seeps to the surface, the predicted distance to which the ERPG-2 would be exceeded for a person who inadvertently enters the plume for five minutes is about 400 m (0.2 miles) and the predicted distance to the LC_{01} is about 250 m (0.15 miles) when the atmospheric stability category is F and the windspeed is 1.5 m/sec (4.9 feet per second), utilizing composition C from Table III-5. These results neglect the possibility that the plume might lift off the ground or exhibit dense gas behavior.

Consequence Analysis of Flare Stack Releases

Results calculated using the GASCON2 (Alp et al., 1990) and FOCUS (Quest, 1992) models and those carried out independently with the SAPLUME model show that, with or without sour gas ignition, the plume emitted from a flare stack is a momentum jet with dilution of the discharge and will rise sufficiently high to avoid concentrations above the ERPG-2 at ground level.

It is possible that a release of very dense gas from an unignited flare could exhibit dense gas behavior. For example, in 1950 in the town of Poza Rica, Mexico, 22 people died from exposure to hydrogen sulfide emitted from a malfunctioning flare at a gas purification plant (McCabe and Clayton, 1952). However, in this case, the gas from the well contained 3 percent by volume of H_2S and 15 percent by volume of CO_2. During the startup period for the desulfurization units to which the gas was sent, partially processed gas containing 81 percent CO_2 and 16 percent H_2S was sent to a flare. It was this processed, heavy vapor and not the produced gas that, upon failure of the flare, descended to ground level. However, despite the limitations in applicability and the unlikelihood of occurrence, this incident is illustrative of the potential for severe consequences when managing a dense gas stream.

Consequence Analysis of Releases Collecting at Ground Level

The specific cases listed in Table III-5 are all less dense than air. This has been the case for all the gas streams investigated for this report for which detailed compositions were documented. Also, note that the most dense composition on Table III-5, stream B which has a density close to that of air, was obtained after some separation and processing for vapor recovery. It appears that the concern about heavy vapors containing H_2S settling or collecting in low-lying areas may be justified for only a fraction of wells such as the previously described Big Piney, Wyoming well blowout and Poza Rica, Mexico flare incident. It is pertinent to address other situations where this concern is justified.

Nine people were killed in an incident in Denver City, Texas, when they were exposed to gas escaping from a well injecting gas into an oil reservoir as part of an enhanced oil recovery project (Layton et al., 1983). The injected gas was composed of 93 percent by volume CO_2 and 5 percent by volume H_2S - clearly denser than air, but as before, gas that was previously processed and not of as-produced composition.

In general, it is possible that releases directly from wells with unusually dense sour gas compositions or associated lines could settle in low-lying areas at ground level. These releases would not be of typical composition. It is also possible that people entering areas of seepage such as those previously described for line releases could confuse these with settling on the ground. It is therefore reasonable to speculate that, in some cases, such concerns could possibly have arisen from seepage events.

The modeling described in the foregoing applies to plumes over flat terrain. In complex terrain, it is unlikely that released gas of typical composition will flow into lower elevations such as valleys because, as previously noted, it is generally not denser-than-air. However, it is very likely that a small or chronic release will follow the flow of the wind. Thus, for example, on cold, still nights there could be flows of air with relatively little turbulence from higher elevations into valleys (katabatic flows). This could carry slowly diluting H_2S with it and potentially cause odors within houses in valleys some distance from the well. This situation would likely not occur during the day when such air flows are uncommon. However, as previously discussed, it is possible for sour gas of unusually dense composition to remain at ground level. Therefore, for such releases, it is conceivable that flow could "channel" through terrain of low elevations such as valleys. This possibility is highly uncertain. The study of the behavior of dense gas flow around obstacles and through rough terrain is controversial and is an area where further research is needed.

Accidental Releases—Prevention, Mitigation, and Emergency Response

The design and operation of sour gas systems require special consideration as a result of the potential hazards presented by a release of H_2S. The hazards of exposure to H_2S can be significantly reduced by the implementation of process safety management principles. A primary emphasis on containment together with design features for the detection and mitigation of losses in containment are necessary for safe operations. The degree of sophistication of individual sour gas system designs will vary depending on site-specific circumstances and age. Older systems may incorporate relatively simple safety designs when compared with current state of the art. The presence of sour oil and gas operations in remote locations or near populated areas may both be justification for the use of advanced designs. Remote areas may be subject to extended releases if accessibility is limited. Process safety management and major safety considerations are discussed below.

Process Safety Management

Facilities that handle hazardous materials have a responsibility to understand the hazards present at their sites and to take steps to ensure that chemical accidents due to these hazards are prevented. Many organizations, including the American Institute of Chemical Engineers - Center for Chemical Process Safety (AIChE-CCPS) and the EPA, have found that major chemical accidents cannot be prevented by hardware or by technology alone. Prevention requires comprehensive management systems designed to identify and control hazards (AIChE, 1989; U.S. EPA, 1988). These management systems are known as Process Safety Management (PSM) and consist of "comprehensive sets of policies, procedures, and practices designed to ensure that barriers to major incidents are in place, in use, and effective. The management systems serve to integrate process safety concepts into the ongoing activities of everyone involved in the process - from the chemical process operator to the chief executive officer" (AIChE, 1989). The Occupational Safety and Health Administration (OSHA) has set standards for process safety management, which are discussed in Chapter IV.

PSM consists of several essential elements that work together to allow safe operation of a facility;

- Management Commitment: Management must adopt a philosophy that makes safety an integral part of operation from the top down; an attitude that all accidents can be prevented and that business must always be conducted safely.

- Process Hazards Analysis or Hazard Evaluation: The purpose of the process hazards analysis is to systematically examine the equipment, systems, and procedures for handling a hazardous substance; to identify the mishaps that could occur, analyze the likelihood that mishaps will occur, and evaluate the consequences of these mishaps; and to analyze the likelihood that safety systems, mitigation systems, and emergency alarms will function properly to eliminate or reduce the consequences of the incident. Thorough process hazards analysis is the foundation for the remaining elements of the PSM system.

- Process Knowledge and Documentation: Facilities document the details of the technology and design of the process, its standard conditions and consequences of deviation from these standards, the known hazards of the chemicals and processes involved and protective systems for protection of workers, the public, and the environment.

- Standard Operating Procedures (SOPs): These are procedures that describe the tasks to be performed by the operator or maintenance worker to ensure safety during operation and maintenance.

- Training: A program to teach those responsible for designing, operating, and maintaining the unit or plant. Elements in a management training system include development of training programs, training of instructors, measuring performance and determining the effectiveness of training. Training is typically carried out by facility managers and training staff.

- Maintenance (Process and Equipment Integrity): A formal program to ensure that equipment is constructed according to design, installed properly, and adequately maintained.

- Prestartup Review: The purpose of this review is to ensure that all elements of process safety, including hardware, procedures, and control software, are in place prior to startup, and that all prior issues of concern have been resolved.

- Management of Change: Management must instruct personnel to recognize change and to evaluate change with regard to process safety.

- Safety Audits: The purpose of safety audits is to measure facility performance, to verify compliance with a sound process safety program, and to determine that risks are being appropriately managed.

- Accident Investigation: Accident investigation is a management process by which the underlying causes of an incident are identified and steps are taken to prevent similar incidents.

- Emergency Planning and Response: Emergencies involving highly hazardous substances can have catastrophic results if not handled properly. Employees need to know and be trained in proper emergency procedures, evacuation requirements, and notification steps.

Major Safety Considerations

Siting. The magnitude of the potential consequences from human exposure to an H_2S release decreases with distance from the sour oil or gas source. Therefore, operations involving H_2S should be situated as far as possible from residential and commercial structures to minimize potential hazards to the public. Prevailing weather patterns (e.g., wind direction), terrain features, transportation routes, population centers, the potential for evacuation, and the potential for access control are some additional factors to be considered in siting decisions. These are site-specific factors that must be determined for each location.

At a minimum, well sites should be fenced to maintain some obstacle to approaching the wellhead.

Materials Selection and Corrosion Prevention. Materials must be chosen that are suitable for the service into which they are placed. Sour oil and gas operations are often conducted under high pressure and corrosive conditions. Therefore, in addition to temperature and pressure considerations, system designs for the wellhead, downhole equipment, and pipelines must incorporate features to minimize the effects of corrosion in order to prevent a breach of containment and accidental release of H_2S. Several national engineering standards governing the choice of materials are applicable. Standards include those by the American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), and the National Association of Corrosion Engineers (NACE). One such standard is NACE Standard MR0175, "Material Requirements for Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment." Also applicable are the API 6A specifications for equipment in high H_2S concentrations in close proximity to occupied structures.

In addition to proper selection of materials, corrosion inhibiting fluids can be used to prevent internal corrosion and cathodic protection can be used to prevent external corrosion. Inhibitor applications include the filling of wells with inhibitor during extended periods of shut-in and injection into pipelines.

Corrosion monitoring programs should be a normal part of the operations and maintenance for sour oil and gas systems so that corrosion problems can be anticipated and repairs made before an accidental release occurs. The need for a corrosion control program and program monitoring was discussed in the first edition of API RP 55, "API Recommended Practices for Conducting Oil and Gas Production Operations Involving Hydrogen Sulfide" (API, 1983). This document has been withdrawn pending publication of an updated, second edition. Additional discussion of RP 55 can be found in Chapter IV. Corrosion monitoring systems can take a variety of forms including external monitoring (ultrasonic or X-ray inspection), corrosion coupons and spool pieces (test pieces), instrumented "pigs", or in-place instrumentation. Pigs are instruments that can be transmitted through lengths of larger diameter piping to take measurements of internal surfaces.

Leak Detection and Mitigation. While systems should be designed to meet the appropriate standards, there is still the potential for releases to occur as a result of human error or equipment failure (e.g., corrosion, impact, etc.). A possible design feature for oil and gas operations is the use of detection systems which monitor for evidence of system leaks and then isolation systems that can be used to shut off leaks. For H_2S-containing systems, detection systems can focus directly on measurement of H_2S, on measurement of pressure changes which could be indicative of a leak, or temperature indicators that can be indicative of a loss of containment and subsequent fire. Signals from such detection systems can be used in modern, sophisticated systems to automatically initiate additional containment measures such as well shut-in or isolation of sections of pipeline. There are national standards for performance and use of H_2S monitoring equipment such as these set by the Instrument Society of America, ISA-S12.15 "Part I: Performance Requirements of Hydrogen Sulfide Detection Instrumentation" and "Part II: Installation, Operation, Maintenance of Hydrogen Sulfide Detection Instruments." Not all systems have leak detection or signalling devices associated with them. Such systems may present a greater hazard potential than those that have devices because detection would have to be by visual means or by smell. Any release would continue until detected.

Flares may malfunction resulting in extinguishment of the flame. This may occur due to several causes including flow of noncombustible compounds (e.g., nitrogen or carbon dioxide) and high winds. Flares can be equipped with automatic ignition devices to reignite extinguished flames and supplemental fuel systems to maintain ignition of the flare gas in the presence of inert gas. Flares should also be constructed at a height that provides for sufficient dispersion of the discharge.

The equipment used to mitigate releases depends on the operations. For well drilling and workover operations, a blowout preventer is used. This piece of equipment consists of high-pressure valves that allow the operator to shut in the well. For operating wells, there can be subsurface shutoff valves which are located in the well as well as above grade valves located at the wellhead and in the lines around surface equipment such as separators. Shut-in may be accomplished automatically via a signal (H_2S concentration, pressure change, temperature) that is received indicating a potential leak. For pipelines, there may also be isolation or shutdown valves located along the pipeline and these may be automatically activated if there is an indication of a leak in the pipeline or at the well. Not all systems will have automatic mitigation capability and isolation would have to be manual in these cases.

Inspection and Monitoring Practices. API RP 55 made recommendations for actions that were intended to monitor performance of the containment system for the sour oil and gas. API RP 55 specifically called for inspection of equipment and system performance to look for indications of corrosion that are indicators of degradation of the sour oil and gas containment equipment. Inspections were specifically recommended for changes in lift performance; changes in pressures associated with packed off annuli; and for the condition of valves, flanges, and connections. The document also recommended that any equipment failures be evaluated to determine the cause of the failure. Particular attention should be paid to the effectiveness of the corrosion control program at a site and corrective action should be considered if there is any indication that the program is inadequate.

API RP 55 also called for the monitoring, maintenance and recalibration of monitoring equipment (temperature, pressure, composition, etc) to make sure it is functioning as intended.

Emergency Procedures. In the event of loss of containment of the sour oil and gas, emergency procedures must be implemented to both restore containment and to protect the public. API RP 55 called for the preparation of a contingency plan for operations involving sour oil and gas. The plans are to contain information that would be needed by personnel responding to the accident at the site. Among the information that should be in the plan according to the API recommended practices are:

1. Location of wells and details on the equipment including flow lines, isolation valves, processing facilities, and tank batteries;
2. Location of safety and life support equipment;
3. Location of telephones and other communication equipment;
4. Potential location of roadblocks for excluding unauthorized personnel for the areas associated with the accidental release;
5. Location of residences, businesses, parks, schools, roads, medical facilities;
6. Areas that could experience elevated H_2S concentrations (e.g. levels greater than 1×10^5 ppb);
7. Potential evacuation routes; and
8. Designated safe areas for operations personnel.

In addition to this information, the plan should have a list of emergency telephone numbers including company supervisors; residences, schools and businesses; nearby operators and service companies; local law enforcement agencies; officials responsible for public facilities that could be impacted; medical assistance personnel, facilities and equipment; and concerned local, state, and Federal agencies.

Beyond the information listed above, the contingency plan should have an immediate plan of action. Among the elements in an immediate action plan are the determination of the potential hazard to the public from the discharge and then an identification of actions to respond to the hazard (e.g. immediate measures to eliminate the discharge, notification of responsible supervisors, establishment of a restricted access zone, evacuation of personnel). API RP 55 also recommended consideration of advanced briefing of public and public officials so they understand the nature of the hazard, the necessity for emergency response plans, and the general steps that would be taken in the event of an emergency. Finally, API RP 55 called for the updating of the plan as necessary to keep the information in the plan current and conducting periodic drills so that personnel are familiar with the type of situations to which they may have to respond.

The Department of the Interior has promulgated regulations that are applicable to sour oil and gas operations on Bureau of Land Management (BLM) property (BLM, 43 CFR 3160). These regulations call for the preparation of public protection plans for drilling and production operations where (1) the 1×10^5 ppb H_2S radius is greater than 50 feet and the area includes locations where the public could reasonably be expected to be (e.g. occupied residences, schools, churches, parks); (2) the 5×10^5 ppb H_2S radius is greater than 50 feet and includes any part of Federal, State, or county or municipal road or highway; or (3) the 1×10^5 ppb H_2S radius is greater than 3,000 ft. where facilities and roads are principally maintained for public use. The requirements for the content of these public protection plans are very similar to those called for in API RP 55.

Abandonment Practices

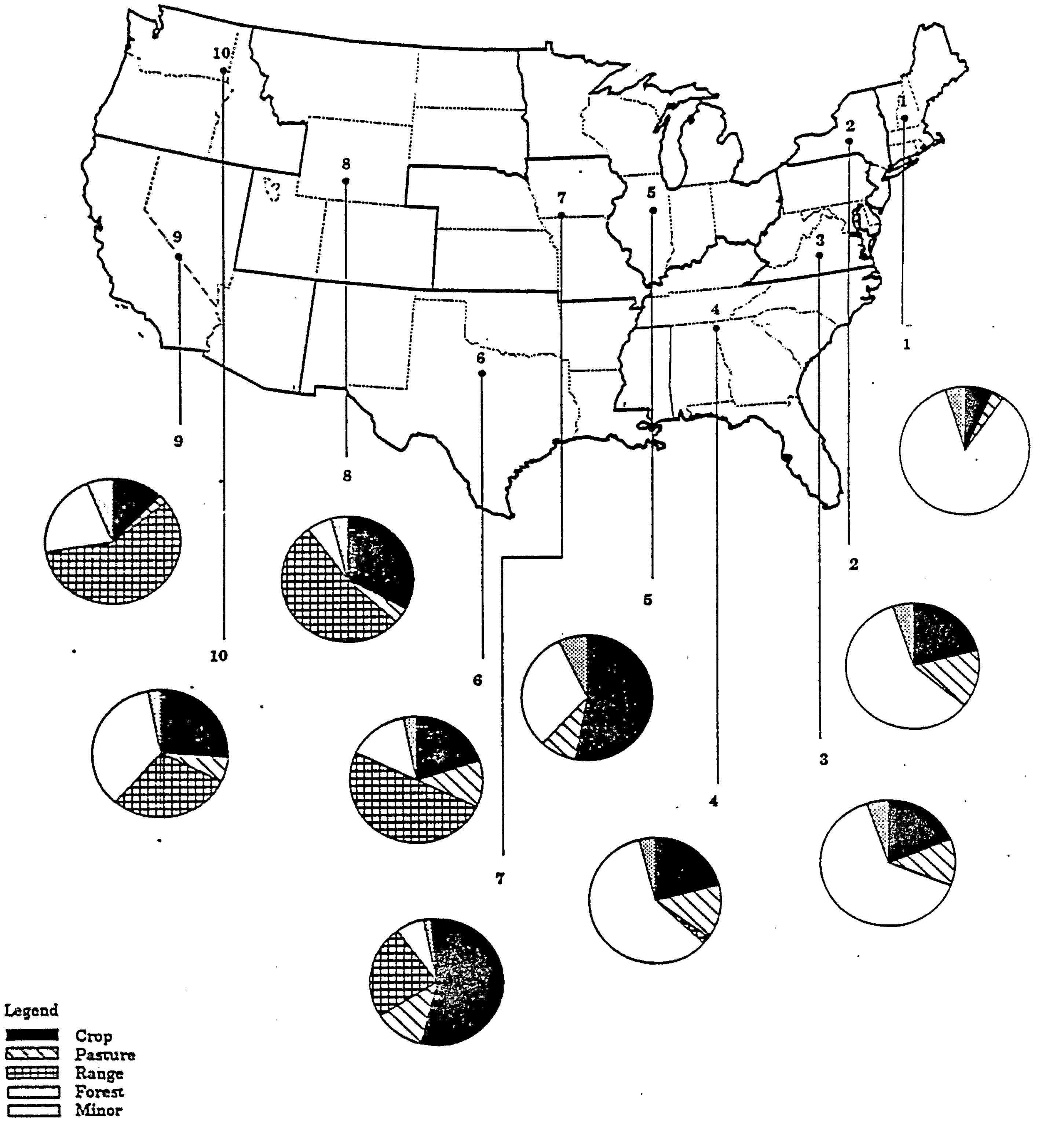
The termination of sour oil and gas production operations normally results in the plugging of the well with cement prior to abandonment by the operator. As a result, a potential exists for H_2S to be released from sour oil and gas from the well and associated equipment if proper precautions are not taken. API RP 55 identified actions that should be taken at the end of operations. The document specifically called for precautions to ensure that H_2S does not present a hazard to the public and the environment. The document called for either air purging or water flushing of equipment followed by opening to the atmosphere. Pipelines then were to be purged and capped. API RP 55 also called for the setting of cement across formations that could produce H_2S.

In some cases, wells may be temporarily abandoned. These wells may also be called "idle" or "inactive." In temporary abandonments, the well will not be plugged with cement but perforations may require isolation. Typically, application must be made and approval given by a state authority to temporarily abandon a well. Conditions justifying temporary abandonment to a State most often include economic conditions and future utility (IOGCC, 1992). Approval is temporary and of limited duration although extensions may be granted at the discretion of the state authority. Depending on the state, initial approval periods range from 6 months up to 10 years. Extensions may be granted for up to an unlimited number of time periods. In many states, but not all, periodic testing is required on idle wells. For example, mechanical integrity and pressure tests may be required. These practices are intended to prevent releases of oil and gas.

Of 215,000 oil and gas wells estimated to have been idle in 1992, approximately 68,000 were thought to have been idled without State approval (IOGCC, 1992). 50,000 of these wells, known as orphan wells, were believed to have been idled by operators who were unknown or insolvent. Although the fact that a temporarily abandoned well has not been reported to the State does not mean the well will be the source of an accidental release, the lack of control and supervision does represent an unsafe situation and may present a greater risk to the public and the environment. The majority of States have developed some funding mechanism and implemented programs to plug and abandon orphan and preregulatory wells although these activities vary widely from state to state (IOGCC, 1992).

Land Use Around Well Sites

Land use can vary enormously around oil and gas wells. The wells may be found in urban areas or open rangelands. Figure III-23 shows current land-use patterns by EPA region (Southerland, 1992). In Regions 6, 8, and 9, which contain the majority of wells in naturally occurring H_2S areas, between 50 and 60 percent of the land is used as range. The three regions represent about 60 percent of the oil and gas producing wells. In the Midwest's Region 5, which contains 12 percent of the nation's producing oil and gas wells, over 50 percent of the land is farmed (U.S. EIA, 1990; U.S. EIA, 1991).



Source: Southerland, 1992.

Figure III-23. Current land-use pattern by EPA region

Regarding urban areas, in California, for example, the Division of Oil and Gas reports that "one-third of California's 1.7 billion barrels of oil reserves are in urban areas or in areas where residential development is increasing. (The H_2S content of these reserves was not available.) The Los Angeles Basin both typifies the situation and is the most complex example. Here, a large metropolitan area lies over one of California's major petroleum-producing provinces. Because oil and gas are so fundamental to the U.S. economy, any recoverable amounts cannot be ignored. Ways have been developed to produce oil and gas safely in urban areas, with minimum negative effects. Urban planners, administrators, and California Division of Oil and Gas engineers work together to ensure a safe partnership between urban life and oil and gas development" (CDC, 1988).

Affected Human Populations

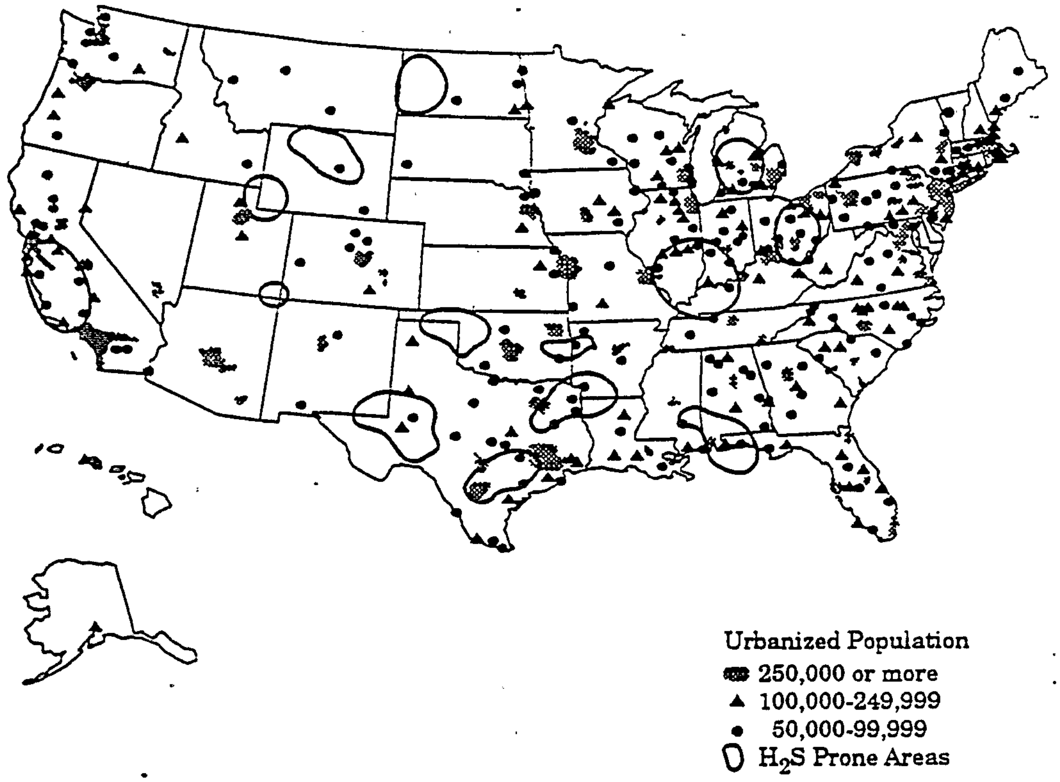
Figure III-24 overlays 1980 census data on the H_2S prone areas to show the proximity of major populations to H_2S deposits. The figure shows that a wide range in population density can be found in H_2S deposit areas. However, a look at the locations of well fields in the United States (Figure III-11) and the number of wells per State (Figure III-12) clarifies the potential exposure of large human populations to H_2S from oil and gas wells.

Data were not available to arrive at statistics on individuals exposed to H_2S emissions. Because the number of wells in the U.S. is so great and the diversity of population density around wells so large, it was not possible to arrive at an estimated affected population. The photographs in this report show that wells may be found in urban, suburban, and rural areas. Populations that could be exposed include adults in work settings (e.g., fire stations), children in schools, shoppers in downtown areas, and people in residential areas.

Affected Environmental Settings

A 1991 study in Wyoming found that, in two years, 237 animals had been killed by H_2S gas. In many oil fields this gas was vented through flare stacks. The researcher stated that when flare stacks are used, it is possible to install devices which would prevent raptors and other birds from using flares as perch sites. Also, wildlife mortality caused by H_2S would be reduced by ensuring that igniters were operating efficiently so that the gas would be properly flared and not accidentally vented directly into the environment (Esmoil, 1991). Based on other accident history, one impact on environmental settings has been the loss of livestock attributed to exposure to H_2S. Sixty percent of the U.S. wells are located in EPA Regions that contain more than 50 percent rangeland. However, many other species of animals and plants are potentially exposed to H_2S concentrations that could cause adverse effects. Testimony for the Clean Air Act Amendments included statements about episodes in the Great Plains that resulted in livestock dying and humans being hospitalized (Audubon Society, 1987).

Twelve percent of all wells are located in EPA Region 5, which is more than 50 percent cropland. As noted in a previous section of this report, soybeans have been



Source: Gas Research Institute, 1990, and Bureau of the Census, 1983.

Figure III-24. Major H_2S prone areas shown in relation to 1980 census data.

determined to be sensitive to H_2S along with other crops. There has been evidence of scorching to young leaves and shoots but no effect on mature leaves (Heck et al., 1970).

Waterfowl habitats of major concern are located in some areas of oil deposits with H_2S, as shown in Figure III-25. Concern has also been expressed about the deterioration of air quality in Theodore Roosevelt National Park (Sierra Club, 1987). Figure III-26 shows the location of national parks and national forests in relation to H_2S deposits.

FINDINGS

1. Human exposure to H_2S may cause death, as well as symptoms including irritation, breathing disorders, nausea, vomiting, diarrhea, giddiness, headaches, dizziness, confusion, rapid heart rate, sweating, weakness, and profuse salivation. Levels greater than 1.5×10^5 ppb are life threatening.

2. No epidemiological studies were found on the effects of H_2S emissions from oil and gas extraction/production.

3. Human acute and chronic health effects data and ecological effects data are limited.

4. H_2S is classified as a Group D carcinogen, meaning not classifiable as a human carcinogen. The inhalation RfC is 9×10^{-4} mg/m^3 (0.67 ppb) in chronic exposures scenarios. This RfC is not appropriate, however, for assessing concentration-response relationships in short-term or accidental exposure scenarios.

5. Few studies exist measuring natural or accidental exposure of wildlife to H_2S; however, wildlife deaths have been reported with blowouts.

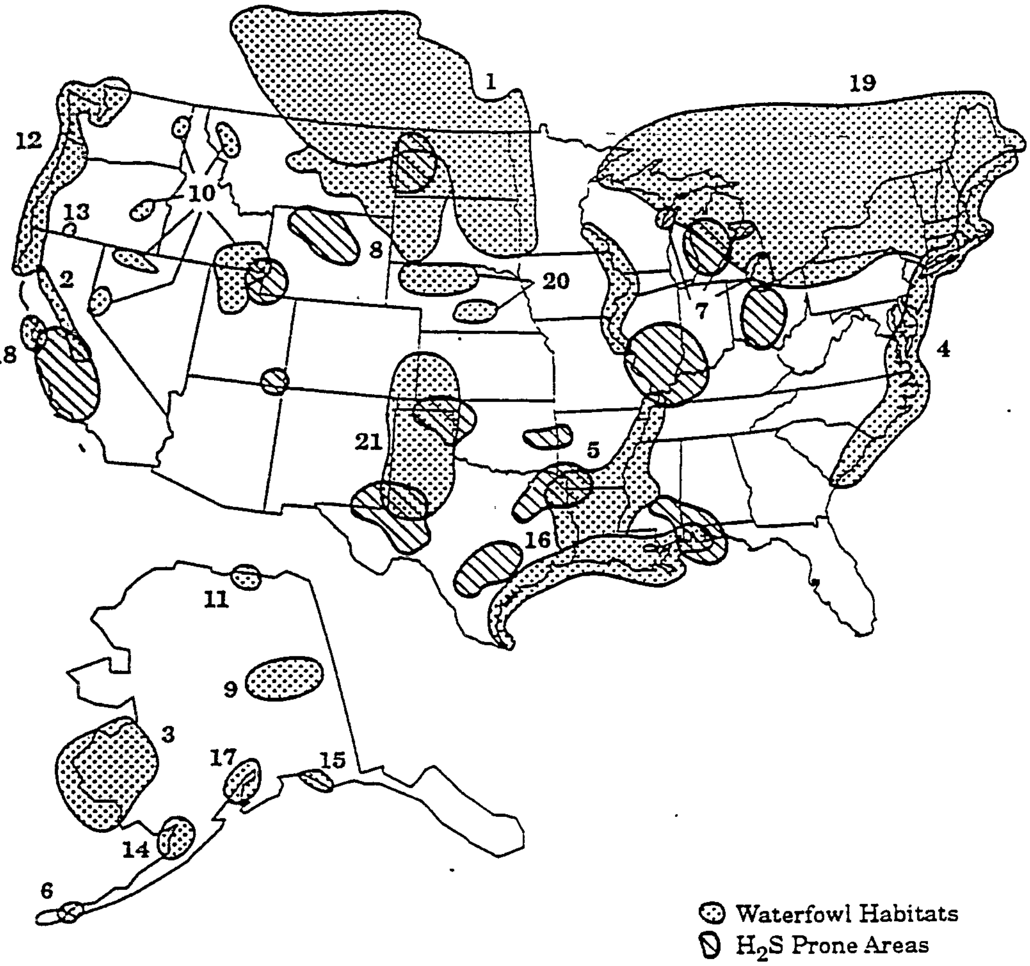
6. High exposure studies have shown young, growing plants to be the most susceptible to H_2S injury (clover, soybean, tomatoes, tobacco, buckwheat).

7. Aquatic LC_{50}s show bluegill = 0.009-0.0478 mg/l.
   NAOEL for mice = 42.5 mg/m^3 (3.05×10^4 ppb).
   LAOEL for mice = 100 mg/m^3 (8×10^4 ppb).

8. Nationwide, vulnerability zones have been characterized as 14 major H_2S prone areas found in 20 states. Texas has 4 discrete H_2S prone areas.

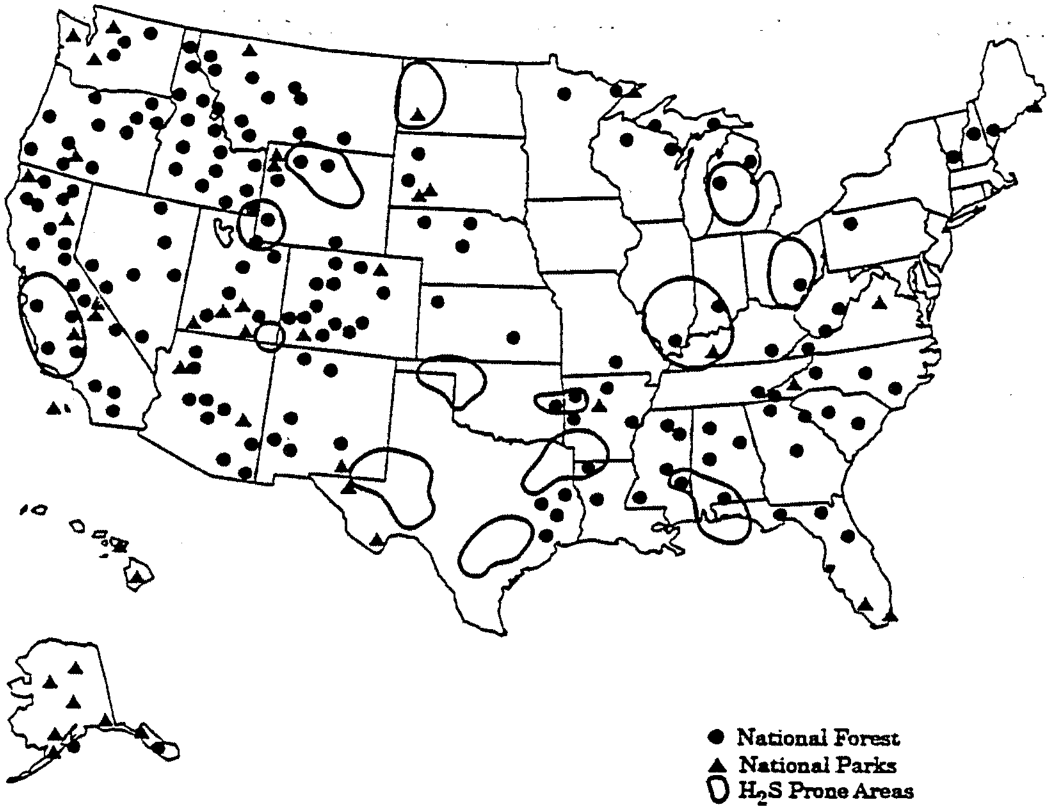
9. North Dakota is the only State known to have routinely monitored ambient H_2S at well sites and surrounding areas.

10. Many oil-and gas producing States require ambient air monitoring for H_2S at gas plants and refineries, but monitoring is not frequently required at oil and gas



Source: Gas Research Institute. 1990.
Coperrider, Boyd, and Stuart. 1986.

Figure III-25. Major H_2S prone areas in relation to waterfowl habitats of major concern (numbers indicate relative priority of concern).



Sources: Gas Research Institute, 1990. Rand McNally, 1992.

Figure III-26. Major H_2S prone areas shown in relation to National Forests and Parks.

extraction facilities, unless H_2S emission violations are suspected or complaints are filed.

11. North Dakota has three background and six special-purpose H_2S monitors. Monitoring periods vary in length from months to over a decade (32.75 years total).

12. At several locations, North Dakota monitoring data verified compliance with State H_2S standards. In two cases, data were from monitoring periods too short to support any conclusions; these were discontinued even though numerous NDAAQS violations were experienced their last year monitored.

13. North Dakota's database showed short-term H_2S concentrations ranging from 0 to 2734 ppb. The median value of all monitoring data was 0 ppb.

14. One North Dakota site had maximum short-term H_2S concentrations an order of magnitude higher than the other eight sites. At this site, more than 3,000 violations were recorded from 1984 to 1986. Concentrations improved greatly from 1986 to 1989, and only one violation occurred after the health-based standards went into effect.

15. Annual average H_2S concentrations at two sites in North Dakota approximated the RfC after introduction of a gas collection system with manifolded flares.

16. North Dakota flare operating efficiencies have been reported to range from 30 to 100 percent. (At 30 percent efficiency, H_2S can be routinely released in significant concentrations.)

17. The risk to the public of an accidental release of H_2S from the extraction of oil and gas is a function of both potential consequences and likelihood of occurrence. Judgements of risk should not be made solely on the basis of consequence analysis alone.
    a. Risks may vary from facility to facility depending on site-specific factors such as the density and distribution of nearby populations and the quality of process safety management and risk management practiced at the facility.
    b. Some facilities present greater risk than others.
    c. Risk reduction must take both consequence and likelihood of occurrence into account.

18. In addition to being toxic, H_2S is corrosive to metals in the presence of moisture and is flammable.
    a. Sour gas is flammable due to its composition of light hydrocarbons and H_2S. However, ignition of sour gas does not generally represent a thermal radiation hazard to the offsite public beyond a distance of about 100 meters.

b. The corrosivity of H_2S in the presence of moisture can cause equipment leakage and other losses in containment.

19. If accidentally released to the air under certain circumstances, H_2S can present a threat to public health and the environment.

   a. Well blowouts, line ruptures, and equipment leakage have caused accidental releases of sour gas with documented impacts on public health and the environment.
   b. The impacts on the public in the United States from sour natural gas releases from extraction activities documented in this study were limited to examples of hospital treatment and evacuation. A number of fatalities have occurred in the workplace. A single incident of the release of carbon dioxide containing H_2S from injection activities to enhance recovery resulted in the 1975 fatalities of eight members of the public.
   c. In this study, several incidents were documented as examples of both livestock and wildlife fatalities resulting from exposure to H_2S from accidental releases of sour gas.
   d. The concentration of H_2S in sour gas may vary from non-lethal levels to lethal levels above 30 percent. Unless there are high concentrations of carbon dioxide and/or hydrogen sulfide, an unprocessed sour gas mixture will usually be less dense than air and will not usually collect at ground level or in low-lying areas if accidentally released.
   e. Releases of sour gas such as from an extinguished flare or from high-pressure equipment failures (e.g., well blowouts and line ruptures) will entrain surrounding air which can cause significant dilution of the hydrogen sulfide and other components in the gas, thereby reducing the potential magnitude of the consequences of its release.
   f. A release of a sour gas mixture that is denser than air and is not significantly diluted through release phenomena (such as a jet from a high pressure source) could, under conservative atmospheric conditions, settle in low-lying areas and present a toxicity hazard. No documented incidents associated directly with oil and gas extraction were identified to support this scenario. Thus, this finding is based on theoretical premises.

20. Atmospheric dispersion modeling of worst-case scenarios shows that accidental releases of sour gas can have a range of impacts from no public impact to doses equivalent to the LC_{01} and AIHA ERPG-3 beyond 10 kilometers from the point of release.

   a. Modeling results indicate that, within a broad range of typical conditions for a <u>vertical</u> well blowout and emission from an extinguished flare, sour gas releases will not cause fatalities to the offsite public. This result would also apply to any similar <u>vertical</u> jet release at wellhead conditions resulting from equipment or line leakage.

b. Modeling results estimate that, in the worst-case, a horizontal release of sour gas from a well blowout (or similar high release rate jet in a horizontal orientation from equipment or piping) could produce fatalities in one percent of the human population exposed at distances up to approximately 10 kilometers.

21. Results from modeling exercises are only gross approximations of what might occur during an actual accidental release. These results are extremely sensitive to factors such as the assumed release rates and assumed meteorological conditions. Precise prediction of downwind effects from an actual release is unlikely for reasons such as:
   a. An actual release may have a different release rate than that assumed for a hypothetical scenario.
   b. The composition of an actual sour gas release may differ from that assumed in a modeling scenario.
   c. The meteorological conditions existing during an actual release may differ from those assumed in a modeling scenario.
   d. The effects of surface roughness (e.g., terrain and obstacles) are not fully understood. It is assumed in the models used that complex terrain and obstacles increase dispersion.
   e. The levels used to predict the onset of toxic effects (i.e., LC_{01} and ERPG-3) are highly uncertain.

22. While analysis of the worst-case scenario can be useful to help facilities and the community surrounding facilities to gain an understanding of the potential magnitude of severe situations, such an analysis does have its limitations. A worst-case scenario should be taken into account along with more probable scenarios when setting priorities for community emergency planning. Note, however, that the worst-case is designed to generate the maximum impact off-site and is considered to be extremely unlikely. The worst-case does not take into account a variety of factors that can significantly reduce downwind impacts.
   a. The worst-case scenario does not take into account the role of process safety management in reducing the probability of loss of containment.
   b. The worst-case scenario does not take into account mitigation actions that can reduce the amount released into the air.
   c. The worst-case scenario assumes terrain and topographical conditions that minimize dispersion of the plume. Actual conditions may result in greater dispersion.
   d. Worst-case meteorological conditions may not exist during an actual release.
   e. The dose that is actually received is uncertain and may be reduced or avoided by sheltering-in-place or evacuation.

23. Technologies have been developed to detect and reduce the amount of sour gas released as a result of breaches in containment. These technologies would serve to protect the public in inhabited areas and to protect wildlife in remote areas with

limited access by facilitating quicker mitigation. These technologies include:

a. Subsurface safety valves;
b. Remotely operated isolation valves;
c. Automatically operated shutoff and isolation valves;
e. Remotely monitored pressure and flow meters;
f. Local and remote audible and visual warning signals; and
g. Automatic flare ignitors and supplemental fuel sources.

In spite of the availability of detection and mitigation measures, all facilities have not uniformly adopted such measures. In addition, the reliability of such equipment and site-specific conditions must be considered before particular technologies are adopted or implemented.

24. Wells drilled in H_2S prone areas may or may not contact H_2S sources.

25. Eight States have a significant overlap of well fields and H_2S prone areas. Therefore, it is roughly estimated that as many as 280,000 oil wells and 54,000 gas wells have the potential to be located in an H_2S prone area. The actual number of sour wells in each State was not available.

26. Population densities in urban areas within ranges of 100,000-249,999 and 50,000-99,999 can be found in H_2S prone areas in California, Texas, Missouri, Florida, Illinois, Kentucky, Oklahoma, Arkansas, Ohio, Michigan, and Wyoming.

27. There have been several documented incidents of wildlife fatalities due to sour oil and gas releases. No incidents have been documented where large-scale wildlife fatalities have been caused by H_2S, and no national statistics on wildlife incidents were found. However, a Wyoming study found 237 animals killed by H_2S in two years.

28. H_2S-prone areas overlap 10 waterfowl habitats of major concern, 18 national forests and 3 national parks.

29. Land use and, therefore, potential human and ecological exposure scenarios can vary enormously around oil and gas wells:
   a. In EPA Regions 6, 8, and 9 which contain the majority of wells in H_2S prone areas (which represent 60 percent of all wells nationwide), 50 to 60 percent of the land is used as range.
   b. In Region 5 (12 percent of U.S. wells), 50 percent of land is farmed.
   c. In California, 1.7 billion bbls of oil reserves are in urban or increasingly developed residential areas.

30. ACGIH's recommended TLV-TWA for H_2S is 1 x 10^4 ppb (14 mg/m^3) and TLV-STEL is 1.5 x 10^4 ppb (21 mg/m^3).

31. AIHA ERPGs for the general public for H_2S are --
ERPG 3 - 1 x 10^5 ppb (1-hr exposure, not life threatening)
ERPG 2 - 3 x 10^4 ppb (1-hr exposure, no irreversible or serious health effects)
ERPG 1 - 100 ppb (1-hr exposure, no mild, transient adverse effects or clearly defined odor).

32. NAS/NRC H_2S guidelines for protecting the general public from the effects of accidental releases are -
90-day continuous exposure guide level - 1 x 10^3 ppb
24-hr emergency exposure guideline level - 1 x 10^4 ppb
10-min emergency exposure guideline level - 5 x 10^4 ppb.

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CHAPTER IV

REGULATORY PROGRAMS AND RECOMMENDED INDUSTRY PROCEDURES

INTRODUCTION

This chapter identifies and reviews the current State and Federal regulatory programs and industry-recommended procedures applicable to either reduce the potential for routine emissions and/or accidental hydrogen sulfide releases from oil and gas production or to mitigate the consequences of such emissions and releases.

STATE REGULATIONS

Currently, there are no national ambient air quality standards (NAAQS) for H_2S. Most oil- and gas-producing States have their own regulations pertaining to H_2S gas. Table IV-1 lists States that have set ambient air quality standards for H_2S emissions.

The EPA gathered and reviewed several States' regulations and related guidance documents and later contacted State agencies to obtain additional information on the unique aspects of the State regulations governing H_2S emissions in the oil and gas industry. EPA staff also met with officials from North Dakota during a trip to North Dakota oil and gas well sites. In addition, the Interstate Oil and Gas Compact Commission (IOGCC) was contacted to obtain information pertaining to regulatory programs (IOGCC, 1990).

This chapter contains a review of existing State regulations for nine States (California, Louisiana, Michigan, New Mexico, North Dakota, Oklahoma, Pennsylvania, Texas, and Wyoming).

These nine States were chosen for review because of their large production volumes, the potential presence of H_2S in their well fields, and their distribution across the United States. The nine States contain over 68 percent of the total oil wells (419,989 wells/613,810 total U.S. wells) and 54 percent of the gas wells (147,360 wells/272,541 total U.S. wells) producing in the United States in 1991 (Petroleum Independent, 1992). For these States, regulatory agencies are identified, H_2S regulations for routine emissions and accidental releases are described, enforcement programs are discussed, records and programs to track accidental H_2S release are included, and the effectiveness of each State program is assessed qualitatively. The qualitative evaluation identifies existing control standards and the populations or ecosystems the standard is intended to protect.

In addition, these States account for 67 percent of the total U.S. oil production and 87 percent of the total U.S. natural gas production (Petroleum Independent, 1992). State regulations for H_2S emissions from the oil and gas industry in Oklahoma, Texas, Michigan,

Table IV-1. Ambient Air Quality Standards for H_2S

State	Concentration (ppb)	Average Time (hours)
California	30	1
Connecticut	200	8
Kentucky	10	1
Massachusetts	14	24
Minnesota	50[a] 30[b]	0.5 0.5
Missouri	500[a] 30[b]	0.5 0.5
Montana	50[c]	1
Nevada	240	8
New York	10	1
North Dakota	200[d] 100[c]	1 24
Oklahoma	100	0.5
Pennsylvania	100	1
Rhode Island	10	1
Texas	80	0.5
Virginia	160	24
Hawaii	40	1
Delaware	30	1
Indiana	50	1

[a]Not to be exceeded more than two times/year.
[b]Not to be exceeded more than two times/five consecutive days.
[c]Not to be exceeded more than one time/year.
[d]Not to be exceeded more than one time/month.

and California were reviewed in greatest detail because they are major oil and gas producing States. These states have extensive regulations dealing with H_2S in the oil and gas industry. California's air quality program is managed by 33 independent air pollution control districts and its Division of Oil and Gas is divided into 6 districts where District heads have great flexibility in enforcing rules. Therefore, California's program is discussed in the greatest detail.

Selected Oil and Gas Producing States

Oklahoma

The H_2S regulations for Oklahoma (10.3.16, "Operation of Hydrogen Sulfide Areas") were listed in *Guidelines for Petroleum Emergency Field Situations in the State of Oklahoma*, a guidance manual that expands on the regulations. The guidance manual contains sections on characteristics and effects of H_2S, recommended guidelines for safe drilling and production operations in an H_2S environment.

The following agencies regulate oil and gas activities in Oklahoma:

- Oklahoma Corporation Commission (OCC), Oil and Gas Conservation Division
- Oklahoma Air Quality Service
- Osage Indian Tribe (OIT)
- U.S. Bureau of Land Management
- U.S. Environmental Protection Agency.

The OCC has jurisdiction over laws and regulations "relating to the conservation of oil and gas and the prevention of pollution in connection with the exploration, drilling, producing, transporting, purchasing, processing and storage of oil and gas..." (OCC, 1986). The OIT has sole jurisdiction regarding oil and gas operations in Osage County. The U.S. Bureau of Land Management has responsibility for cases where both surface and mineral rights are owned by the Bureau or by an Indian tribe other than the Osage Tribe.

As noted earlier in this chapter, Oklahoma has an H_2S ambient air quality standard. This regulatory program (administered by the Air Quality Service) is used to control routine emissions (through permit) from oil and gas facilities.

The accidental release of H_2S from facilities is regulated by the OCC. Rule 165:10-3-16 of the OCC rules requires operators to assess their facilities for H_2S release potentials that would cause harm to the public. The rule is applicable to all facilities that handle natural gas containing 1×10^5 ppb H_2S or more and have a significant radius of exposure to cause adverse effects on the public with the exception of storage tanks. The "radius of exposure" is that distance from a source where the ground level concentration of hydrogen sulfide resulting from a release of gas from a facility is 1×10^5 ppb or 5×10^5 ppb whichever is applicable in the Rule. The Rule applies as follows:

- Does the facility (drilling, producing, injection, storage, etc.) handle hydrocarbon fluids containing 1 x 10^5 ppb H_2S or more? If yes;

- Determine the 1 x 10^5 ppb radius of exposure using an equation required in the Rule or other methods approved by the Commission. The H_2S escape rate from the facility must be determined as required by the Rule.

- If the 1 x 10^5 ppb radius of exposure is in excess of 50 feet, warning, marker and security provisions must be provided at the facility.

- If the 1 x 10^5 ppb radius of exposure is in excess of 50 feet and includes a public area or if the 5 x 10^5 ppb radius of exposure is in excess of 50 feet and includes a public road or if the 1 x 10^5 ppb radius of exposure is in excess of 3000 feet, control and safety equipment and a contingency plan must be provided for the facility.

- Facility storage tanks near atmospheric pressure containing 5 x 10^5 ppb or greater H_2S must have warning signs, wind indicators and possible fencing. Radius of exposure calculations are not applicable to storage tanks.

- H_2S training, injection or flaring provisions, accident notification and other requirements are addressed in the Rule (personal communication, W. Freeman, Shell Oil, 6/23/93).

The OCC does not keep an emissions inventory of accidental H_2S releases, but it does keep an inventory of wells with actual or potential H_2S problems. Furthermore, an inventory of inspection data is kept by individual inspectors in the State and the local field offices. Any emissions of H_2S exceeding the OCC standard of 2.5 x 10^4 ppb must be reported to the OCC by the emitting facility. Rule 3-2032, H_2S Operation, is intended to provide for the protection of the public's safety in areas where H_2S concentrations greater than 1 x 10^5 ppb may be encountered.

Drilling facilities are not required to submit data periodically to show that they are in compliance with regulations. Facilities report release of H_2S on an "honor system" once permits are granted. When noncompliance is discovered, the OCC can use administrative proceedings to shut down or fine the operation. However, in recent years, there has been no evidence of noncompliance with the H_2S regulations.

The OCC lists training requirements for employees who will work in areas of potential H_2S exposure. The training must cover hazards and characteristics of H_2S, operation of safety and life support systems, and emergency response procedures. OCC safety inspectors attend annual industry-sponsored training programs in order to stay current on safety developments and to check the safety of their breathing equipment. Each H_2S inspector is required to have an H_2S monitor, a manual, H_2S gas monitoring test tubes, and a self-contained air breathing apparatus. Specific H_2S provisions also exist regarding H_2S detection and alarm equipment, accident notification, injection, and flaring. In 1991, the OCC and the industry jointly sponsored an H_2S safety seminar. A film about H_2S safety was presented to regulatory and industry personnel, and questions about H_2S safety were answered. Safety training has also been provided to local police, fire, sheriff and ambulance services, and to interested oil and gas operators, as requested.

The enforcement, field monitoring, and inspection departments of the OCC employ 69 people. The State currently has two H_2S inspectors and a third is anticipated. In 1991, one emergency involving the accidental release of H_2S was reported to the OCC. However, the accident, which resulted in the death of one worker, was not related to the extraction of oil and gas resources.

Texas

Six agencies regulate oil and gas activities in Texas:

- Railroad Commission of Texas
- Texas Water Commission
- Texas Air Control Board
- Texas Parks and Wildlife Department
- U.S. Army Corps of Engineers
- U.S. Environmental Protection Agency.

The Railroad Commission regulates most of the operations of the oil and gas industry but has no authority over the Clean Air Act Amendments. The Railroad Commission is responsible for the well spacing, construction requirements (casing etc.), and most aspects of environmental protection and works with other State Agencies to ensure that their concerns are addressed. The Texas Water Commission works with the Railroad Commission on water quality issues. The Texas Air Control Board has jurisdiction over the regulation of oil field activities that generate air emissions. The Texas Parks and Wildlife Department investigates fish kills and water pollution complaints and evaluates the effects of discharged wastes on fish and wildlife. The Railroad Commission has jurisdiction over all oil and gas activities on Federal lands in Texas, regardless of who owns the mineral rights. The U.S. Army Corps of Engineers has permitting responsibility for activities that would affect statutory wetlands.

The Texas Air Control Board (TACB) is responsible for enforcing the Texas ambient air quality standard for H_2S (discussed previously). Certain allowances are made from the air standard if the hydrogen sulfide affects only property used for other than residential, recreational, business, or commercial purposes, such as industrial property and vacant tracts and range lands not normally occupied by people (i.e., the emission limit is raised to 120 ppb/30 min). If an operator violates these ambient air levels, corrective action must be taken such as flaring, installation of vapor recovery, etc. Consequently, the unauthorized emission of H_2S that exceeds the time weighted averages for the land use discussed above is a violation of regulation and must be addressed by the operator. In addition, the TACB requires permits for facilities that handle sour gas emissions from crude oil storage which also address emergency releases from these type facilities.

Texas regulations on H_2S for drilling, extraction, and abandonment are listed under Statewide Rule 36 - Hydrogen Sulfide Safety, Section 3.36 (051.02.02.036, "Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas," as amended September 1, 1976). The Hydrogen Sulfide Safety Rule in Texas—issued to address accidental releases—applies to facilities that could expose the public to concentrations of H_2S in excess of 1×10^5 ppb as a result of an accidental release. Operators handling hydrocarbon fluids containing 1×10^5 ppb or more H_2S must determine if the Rule applies to their facility. If it does, they must calculate the radius of exposure; determine if the public will be impacted; and, if so, install warning signs, ensure security measures, address storage tank requirements, install appropriate safety equipment, develop contingency plans, provide training and implement other requirements as necessary. In addition, all operators subject to Rule 36 must submit a Certificate of Compliance to the Railroad Commission to demonstrate that they have complied with these requirements. This rule requires that employees working in H_2S areas be trained in the characteristics and effects of the gas. The Railroad Commission of Texas publishes a training manual containing this information. The Texas and Oklahoma regulations are virtually identical. Most of the Texas regulations were discussed in the previous section on Oklahoma regulations. The Hydrogen Sulfide Safety Rule in Texas does require safety equipment, alarm equipment, monitors, etc., but does not specify exact types in an attempt to remain flexible and allow for new technology. It was designed for the protection of the general public rather than industry, since OSHA rules are designed to protect industry workers (personal communication, W. Freeman, Shell Oil, 6/23/93).

In Texas, the Railroad Commission does keep an emissions inventory on accidental H_2S releases. Any emissions of H_2S that are found to be of sufficient volume to present a hazard and/or any H_2S-related accidents must be reported to the Railroad Commission by the emitting facility. Operator certificates are required by the Railroad Commission to demonstrate that prevention and response measures have been taken to address accidental releases of H_2S.

There was one case of noncompliance during 1991, which involved natural gas leaking from a pipeline. The Railroad Commission canceled the Certificate of Compliance for the operators of the well, which prevented the facility from producing or selling the product until the leak was fixed. In 1991, there were emergencies involving the accidental releases of H_2S. Those accidents were discussed in Chapter III.

The enforcement, field monitoring, and inspection departments of the Railroad Commission employ 215 people. Ground testing for traces of H_2S is performed near the wells. Emission data on each well are submitted to the Railroad Commission using the Form of Compliance. When noncompliance is discovered, the Commission uses administrative proceedings to implement the following enforcement actions: enforcement letter, pipeline severance, zero allowable emissions, sealing, permit revocation and/or administrative penalties. The Railroad Commission may also seek civil penalties through the Attorney General's Office.

Michigan

The Michigan regulatory program is published in *Michigan's Oil and Gas Regulations - Act 61* (P.A. 1939 as amended and promulgated rules - Circular No. 15, revised in 1987, MDNR). Most of the regulations in the Michigan guidance were covered in the sections on Texas and Oklahoma regulations.

A review of *Michigan's Oil and Gas Regulations* reveals that the State has a comprehensive set of regulations dealing with H_2S. The Michigan rules require extensive training for all employees and contractors involved in drilling, completing, testing, producing, repair, workover or service operations. Employees must receive training in the following areas: physical properties and physiological effects of H_2S, effects of H_2S on metals and elastomers, emergency escape procedures, location and use of safety equipment, the location and operation of detection and warning systems and the location of primary and secondary briefing areas. Briefing areas are defined in *Michigan's Oil and Gas Regulations* as the areas "nearby where personnel can assemble in case of an emergency." Michigan defines safety equipment as including items such as first aid kits, dry chemical fire extinguisher, ropes, flare guns, portable H_2S detectors and warning signs.

In addition to training requirements, the Michigan oil and gas regulations contain comprehensive rules for the preparation of a contingency drilling plan in order to provide a plan for alerting and protecting personnel and the public in case of an emergency.

Five agencies regulate oil and gas activities in Michigan:

- Michigan Department of Natural Resources (MDNR)
- Michigan Department of Commerce, Public Service Commission
- U.S. Forest Services
- U.S. Bureau of Land Management
- U.S. Environmental Protection Agency.

The Department of Natural Resources is responsible for the well spacing, construction requirements (casing, etc.), and most aspects of environmental protection. The Michigan Public Service Commission regulates the production of gas from dry natural gas reservoirs and the safety of gas pipeline construction. When dealing with split estate situations, the U.S. Forest Service will issue a Special Use Permit which allows an operator to drill within the forest boundary. When both the forest surface and corresponding mineral rights are Federally owned, the U.S. Bureau of Land Management (BLM) issues drilling permits and the U.S. Forest Service issues Surface Use Plans. The BLM issues drilling permits in all cases related to onshore Federal mineral estates (personal communication, T. Alexander, DOE, 2/22/93).

Worker safety issues are the responsibility of the Michigan Department of Labor. Part 57 of the General Industry Safety Standards Commission Safety Standards deals with oil and gas drilling operations safety standards. Under Rule 5717(1), the drilling and servicing of wells containing H_2S shall be conducted as prescribed in the American Petroleum Institute's Recommended Practice No. 49 (API, 1987).

The MDNR's Air Quality Division regulates H_2S emissions from all sources in the oil and gas industry. Rule 336.1403 states: "It is unlawful for a person to cause or allow the emission of sour gas from an oil or natural gas producing or transporting facility or a natural gas processing facility without burning or equivalent control of hydrogen sulfide and mercaptans." The Rule does allow operators with stripper wells to emit small quantities of H_2S unless one complaint is received from the public which would require some type of abatement technique to be imposed. All facilities handling H_2S are subject to these regulations.

The Geological Survey Division (GSD) of the Department of Natural Resources regulates accidental releases of H_2S in the oil and gas industry. In addition, it overlaps with the Air Quality Division on emission controls at production facilities. It appears that two agencies in the MDNR regulate H_2S handling facilities. Under Rule 299.1911-1939, operators handling hydrocarbon fluids containing more than 3×10^5 ppb H_2S must define a Well Class (defined by the radius of exposure in Rule 299.1912) to determine the applicability of the Rule. The radius of exposure is defined using the same dispersion equation as Texas Rule 36. The Rule addresses equipment standards, location standards for drilling and production equipment, contingency planning, training, drilling, testing, production operations, servicing operations and nuisance odor requirements (personal communication, W. Freeman, Shell Oil, 6/23/93).

The enforcement, field monitoring, and inspection departments for oil and gas regulation by the Geological Survey Division (GSD) of the MDNR employ 47 people. Wells are retested one year after the initial well test was performed, to check for compliance with laws. Further periodic tests are required only at the request of the MDNR. When a well is not in compliance, the MDNR can use administrative proceedings to shut down drilling processes and production, stop issuing permits to drill, stop well ownership transfers, and issue fines. Fines are also issued for falsifying records required by the GSD enabling legislation (Act 61, P.A. of 1939, amended). Violation of the Act or a rule or order under the Act carries a penalty of not more than $1,000.00 per day that the violation continues. In 1991, there was no evidence of noncompliance for the release of H_2S.

The MDNR does not keep an emissions inventory of the accidental releases of H_2S from well blowouts and flare gas releases. Emissions of H_2S are reported by industry personnel to MDNR field personnel, who may keep records on the releases. One incident was reported to the MDNR in 1990, which involved a pumper who was working on a storage tank. The exact date and nature of the incident were not available.

California

The following agencies regulate oil and gas activity in California:

- California Department of Conservation, Division of Oil and Gas
- California Water Resources Control Board and the nine Regional Water Quality Control Boards
- California Department of Health Services
- California Department of Fish and Game, Office of Spill Prevention and Response
- California/EPA Department of Toxic Substances Control
- California State Fire Marshall's Office
- California Public Utilities Commission
- California OSHA
- California Air Resources Board and the county or multi-county regional Air Pollution Control Districts
- California Governor's Office of Emergency Services
- State Lands Commission
- California Coastal Commission
- Local government agencies
- U.S. Bureau of Land Management
- U.S. Department of Energy
- U.S. Environmental Protection Agency.

The Division of Oil and Gas of the California Department of Conservation is responsible for the management and conservation of oil and gas resources. The Division issues permits for and inspects the drilling, reworking, and abandonment of oil and gas wells. Under delegated authority from the EPA, the division also issues underground injection control well permits for Class II injection wells.

Division 3 - Oil and Gas, part of the California Code of Civil Procedure, contains the California laws for conservation of petroleum and gas (CDC, 1991). Table IV-2 highlights key sections of the law applicable to H_2S releases. Although, there is no quantitative limit to H_2S emissions, the law grants the supervisor of the Oil and Gas Division, discretionary authority to control H_2S releases to ensure protection of human health and the environment.

California's Code of Regulations contains the oil and gas regulatory program enforced by the Division of Oil and Gas. These regulations are highlighted in Table IV-3. These rules include the definition of the term "critical well," requirements for contingency plans,

Table IV-2. Highlights of California Laws for Conservation of Petroleum and Gas Pertaining to H_2S Emissions

Ch., Art., Section	Subject	Description
1, 4, 3219	Blowout prevention	Where high-pressure gas exists, use adequate casing and safety devices
1, 4, 3224	Order for repair	Authorizes supervisor to order tests or repairs needed to prevent damage to life, health, natural resources, etc.
1, 4, 3228	Abandonment of wells	Protects ground and surface water from gas-bearing strata
1, 4, 3235	Complaint	Authority to investigate complaints
1, 4, 3236	Penalty	For obstructing enforcement, \$100 - \$1,000 or up to 6 months imprisonment per offense
1, 4.1, 3241	Strategy to extract gas in high risk areas	Develop strategy to extract hazardous gases from abandoned wells to protect public health and safety
1, 4.2, 3251	Define "hazardous well"	Poses danger to life, health, or natural resources
3, , 3600	Spacing wells	Well must be at least 100 feet from parcel's boundary or public road

rules include the definition of the term "critical well," requirements for contingency plans, and environmental protection.

The Division of Oil and Gas has also published a guidance document on H_2S, *Drilling and Operating Oil, Gas, and Geothermal Wells in an H_2S Environment* (Dosch and Hodgson, 1986). This guidance document reflects the American Petroleum Institute's publication RP 49, *Safe Drilling of Wells Containing Hydrogen Sulfide* (API, 1987) and recommends safety procedures for H_2S release scenarios. The California Division of Oil and Gas (CDOG) is divided into six districts. Figure IV-1 shows the six districts and the distribution of H_2S in California, presenting parts per million of H_2S gas in some California oil and geothermal fields. Table IV-4 shows the documented concentration by oil field in each district. Three of the districts are discussed here.

District 1 of the Division of Oil and Gas has three oil and gas inspectors and seven energy engineers who inspect well drilling and rework operations. The inspectors wear tri-gas monitors (H_2S, oxygen, and combustibles). The well-permitting program does not specify H_2S limits. All wells are inspected at least once a year. Idle wells must be pressure-tested periodically to minimize casing leaks. Steam flooding, an enhancement process that often creates H_2S, is used frequently in the district. District 1 authorities know of past H_2S incidents leading to human injuries; however, because records are not computerized, exact data are not available (personal communication, K. Carlson, CDOG, 8/27/92).

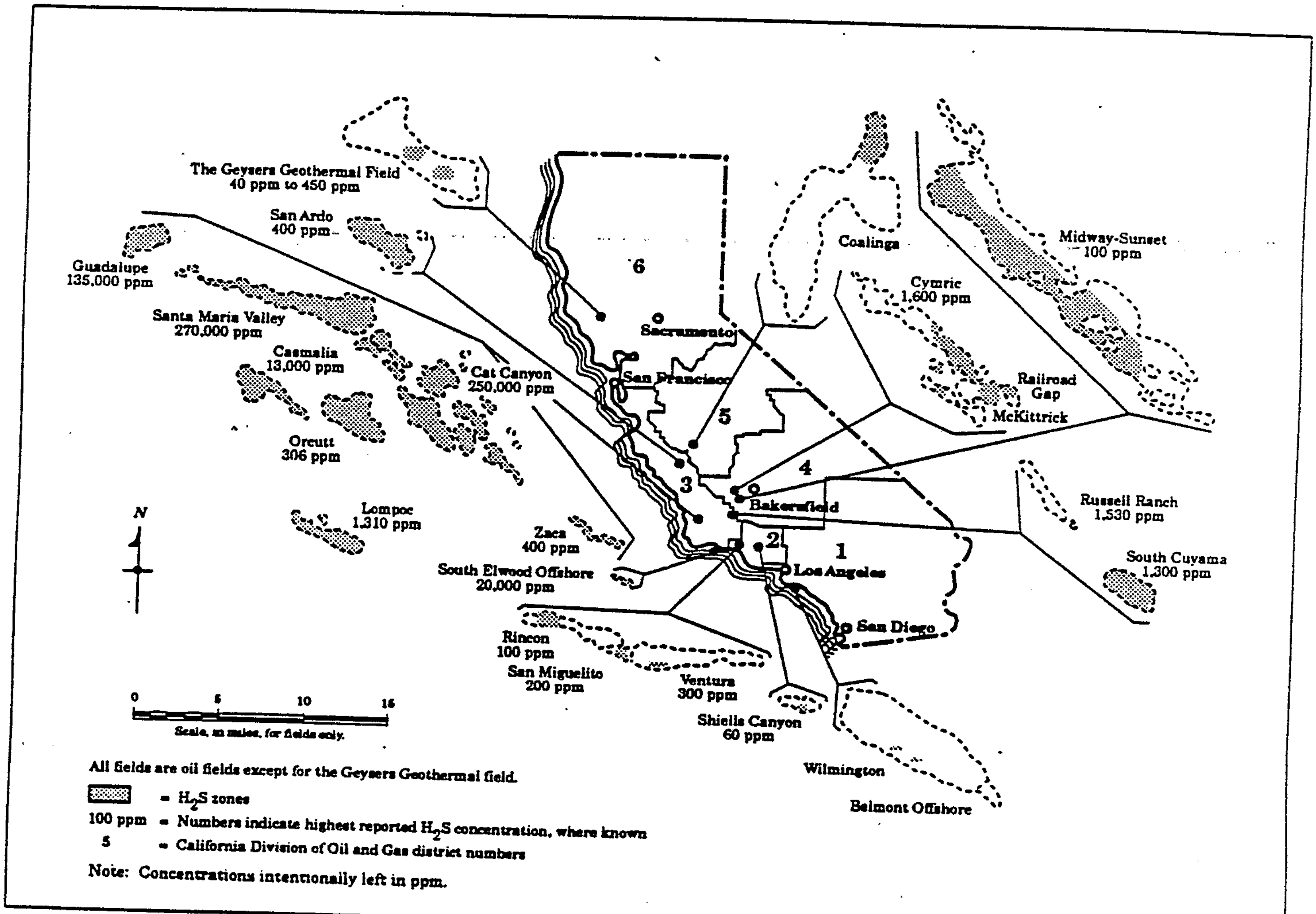
District 3 has 1,929 producing wells and 2,845 shut-in wells (i.e., no production is made on the well; its pump is turned off, the stuffing box is closed, and it is inspected to ensure no leakage). Three field inspectors cover District 3 (personal communication, A. Kollar, CDOG, 8/28/92).

District 4, which includes Kern County, has nine field inspectors, each equipped with an "escape pack" for H_2S protection. An environmental inspection is performed for every lease on every well. The inspection covers the surface area, well condition, tank condition, and operation. There are more than 40,000 wells in Kern County alone. District 4 had no records of H_2S incidents. However, inspectors in Kern County/San Joaquin Air District (described below) have documented incidents of H_2S releases (personal communication, R. Bowles, CDOG, 8/27/92).

The California Air Resources Board is authorized to enforce a statewide ambient air quality limit for H_2S emissions of 30 ppb over one hour's averaging time. However, California's air quality program is managed on a smaller scale by the 33 county or multi-county air pollution control districts (APCDs) shown in Figure IV-2 (CA Air Resources Board, 1991). Each district acts as an independent regulatory agency, establishing and

Table IV-3. Highlights of Title 14, Chapter 4 of the California Code of Regulations – Development, Regulation, and Conservation of Oil and Gas Resources

Article, Section	Subject	Description
Subchapter 1		
1, 1712	Scope	Onshore drilling and production; grants Oil and Gas Division Supervisor authority to establish field rules
2, 1720	Critical well	Addresses distances to public areas and navigable waters
2.1, 1721	Well spacing	Objectives include protecting public health, safety, welfare and the environment
3, 1722	General	Good oilfield practices, blowout prevention and control plan, prompt reporting of significant gas leaks
3, 1724.3	Well Safety Devices	Required of certain critical wells
3, 1724.4	Testing/inspecting Safety Devices	Test at least every 6 months
Subchapter 2	Environmental Protection	Requires covers on well cellars, no excessive leakage including wellheads and pipelines



Source: Dosch and Hodgson, 1986.

Figure IV-1. Parts per million of H_2S gas in some California oil and geothermal fields. Data compiled in 1976.

Table IV-4. H_2S in California Oil, Gas, and Geothermal Fields

Oil and Gas District	Fields with H_2S Concentrations $1x10^5$ ppb or Above	Fields with H_2S Concentrations Under 100 ppm	Fields with H_2S Odor, But With Concentrations Unknown
1	—	—	Wilmington, Huntington Beach, Newport, Torrance, Brea Olinda
2	Rincon, 1×10^5 ppb San Miguelito, 2×10^5 ppb Ventura, 3×10^5 ppb	Shiells Canyon 60 ppm	Aliso Canyon, Bardsdale, Big Mountain, Del Valle, Las Llajas, Oak Park, Oakridge, Ojai, Piru, Santa Paula, Santa Susana, Simi, South Mountain, Tapo Canyon So., Temescal, Torrey Canyon, and West Mountain
3	Casmalia, 1.3×10^7 ppb Cat Canyon, 2.5×10^8 ppb Cuyama So., 1.3×10^6 ppb Elwood So., Offshore, 2×10^7 ppb Guadalupe, 1.35×10^8 ppb Lompoc, 1.31×10^6 ppb Orcutt, 3.06×10^5 ppb Russell Ranch, 1.53×10^6 ppb San Ardo, 4×10^5 ppb Santa Maria Valley, 2.7×10^8 ppb Zaca, 4×10^5 ppb	—	Capitan Onshore, King City Four Deer
4	Midway Sunset, 1×10^5 ppb Cymric, 1.6×10^6 ppb	—	North Belridge, South Belridge, Blackwells Corner, Edison, Northeast Edison, Kern River, Lost Hills, McKittrick, Mount Poso, Poso Creek, Railroad Gap, and Wheeler Ridge
5	—	—	Coalinga
6	—	—	—
Geothermal District			
G3	The Geysers, $4x10^4$ - $4.5x10^6$ ppb	—	—

H_2S in some California oil and geothermal fields. Data compiled in September 1976. (Data in the first two columns are on Figure IV-1).

Source: Dosch and Hodgson, 1986.

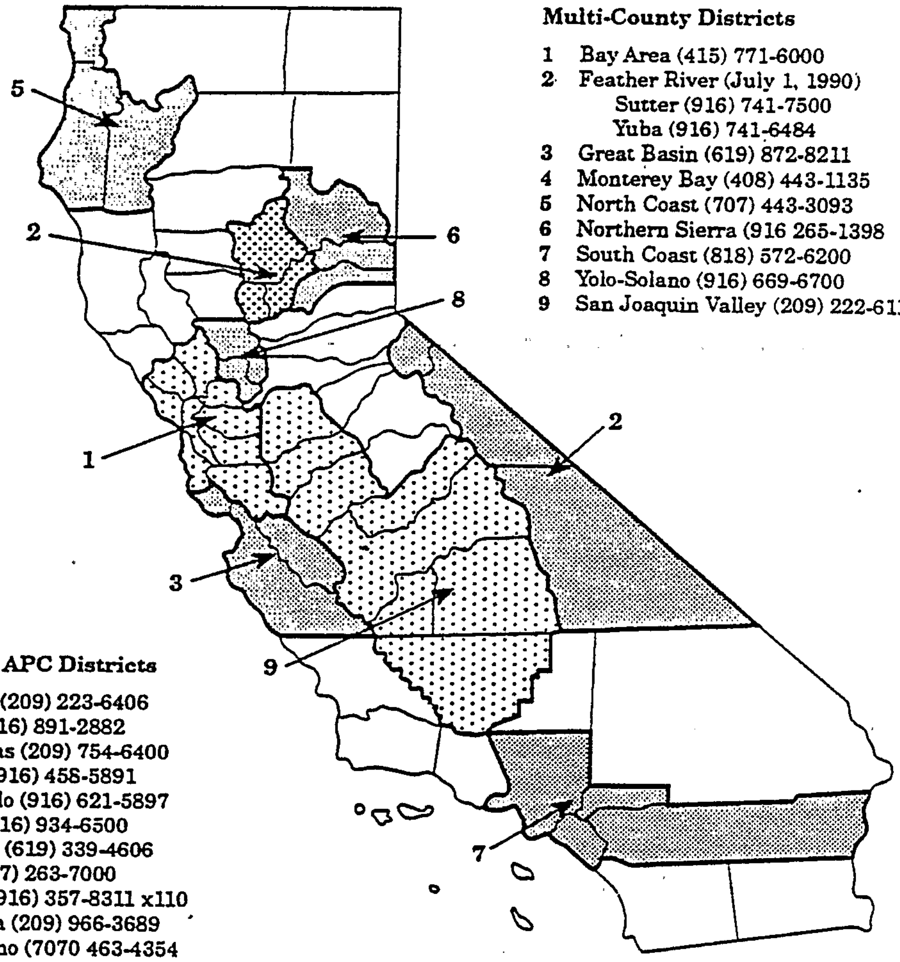
enforcing air quality rules tailored to the district's needs. Districts with significant oil production are:

Ventura County
Santa Barbara County
San Joaquin Unified Air District
South Coast Air Quality Management District
Monterey Bay Unified Air District
Bay Area Air Quality Management District.

This report highlights H_2S emissions programs in four districts: Ventura County, Santa Barbara County, San Joaquin Unified Air District, and the South Coast District.

Ventura County has Rule 54, "Sulfur Compounds," in place for air emissions containing sulfur compounds. This rule, adopted in 1968 and most recently revised in 1983, includes a limit for H_2S not to exceed 1 x 10^4 ppb by volume at the point of discharge. The point of discharge includes any distinguishable emission point such as valves, flanges, or process vents. There are no control technology regulations for H_2S in Ventura County other than these equipment standards. Another H_2S rule requires that the aboveground average concentration at or beyond the property boundary shall not be in excess of 60 ppb for over 3 minutes. The Ventura County limits were adopted in 1968 when the APCD was formed. Natural emissions of H_2S are low in the county's oil well fields, and H_2S monitoring is only performed when a problem is suspected (i.e., when the odor is detected). The APCD uses hand-held monitoring devices to inspect problem areas. No routine monitoring records are kept on file in Ventura County, but wells are inspected at least once a year, with large wells inspected more frequently (personal communication, K. Duval, Ventura APCD, 8/29/92). Ventura County has an enforcement staff of about 20 people, including 8 field inspectors (personal communication, K. Duval, Ventura APCD, 11/23/92).

Emission standards in Santa Barbara County are basically the same as in Ventura County. However, tighter emission limits are applied in parts of the county with SO_2 (an oxidation product of H_2S) nonattainment areas. Rule 309, "Specific Contaminants," for Santa Barbara County states that sulfur recovery units shall not emit more than 5 x 10^5 ppb as SO_2 or 1 x 10^4 ppb as H_2S. Rule 310 for odorous organic sulfides states that concentrations of organic sulfides beyond the property boundary shall not exceed 60 ppb/3 minutes or 30 ppb/hr. For gas produced and used as fuel in equipment on a well site, the sulfur content limit in the county's northern air shed is 7.96 x 10^5 ppb sulfur; in the southern county air shed, the limit is 2.5 x 10^5 ppb. Control technologies are not used on well heads for H_2S emissions. However, controls do exist for volatile organic compound (VOC) emissions from well fittings, stuffing boxes, well cellars, sumps and pits. Rules are being developed to require these controls, primarily in the surface area of the well cellar to control the release of VOC. This technology will also control H_2S emissions indirectly. The county's 10 field inspectors inspect wells for all types of emission sources at least once a year. H_2S violations via the total sulfur emission limit are not a problem because by the time



Multi-County Districts

1 Bay Area (415) 771-6000
2 Feather River (July 1, 1990)
  Sutter (916) 741-7500
  Yuba (916) 741-6484
3 Great Basin (619) 872-8211
4 Monterey Bay (408) 443-1135
5 North Coast (707) 443-3093
6 Northern Sierra (916 265-1398
7 South Coast (818) 572-6200
8 Yolo-Solano (916) 669-6700
9 San Joaquin Valley (209) 222-6111

County APC Districts

Amador (209) 223-6406
Butte (916) 891-2882
Calaveras (209) 754-6400
Colusa (916) 458-5891
El Dorado (916) 621-5897
Glenn (916) 934-6500
Imperial (619) 339-4606
Lake (707) 263-7000
Lassen (916) 357-8311 x110
Mariposa (209) 966-3689
Mendocino (7070 463-4354
Modoc (916) 233-3939 x401
No. Sonoma (707) 433-5911
Placer (916) 889-7130
Sacramento (916) 386-6650
San Bernardino (619) 243-8920
San Diego (619) 694-3307
San Luis Obispo (805) 549-5912
Santa Barbara (805) 961-8800
Shasta (916) 225-5674
Siskiyou (916) 842-8029
Tehama (916) 527-4504
Tuolumne (209) 533-5693
Ventura (805) 654-2806

Source: California Air Resources Board, 1991.

Figure IV-2. Multi-county districts.

the ambient air quality standard is exceeded, the operator has already been alerted to a safety problem and is responding. The county has seven currently active H_2S ambient monitoring stations; however, these are at oil and gas processing facilities, rather than at well fields (personal communication, J. Top, St. Barbara APCD, 8/20/92).

The San Joaquin Unified Air District enforces Rule 407, "Sulfur Compounds," which limits the emission concentration of sulfur compounds at the point of discharge to 0.2 percent volume calculated as SO_2 (or 2 x 10^6 ppb SO_2). This rule, adopted in 1972 and renumbered in 1989, applies to any gas line or vapor control line from a well. Rule 220.1, "New and Modified Stationary Source Review Rules," has a trigger value for H_2S or total reduced sulfur or sulfur compounds other than SO_x of 54.79 lb/day. If this value is exceeded, the responsible party must use Best Available Control Technology (BACT) on the emission source. Rule 220.1 was adopted in September 1991 and revised March of 1992.

The San Joaquin District does not look at or enforce H_2S regulations until the 2 x 10^6 ppb SO_2 emission limit is exceeded, because the rule is based on the impact of SO_2 on human health and the environment, not on the health effects of H_2S. No ambient monitoring of H_2S is required by the district. However, the oil companies are required to keep their own records of SO_2 monitoring for two years. Companies also have H_2S monitoring data, and the State has the authority to request these data at any time (personal communication, M. Amundsen, San Joaquin, 8/21/92).

Kern County, part of the San Joaquin Unified Air District, has three of the largest producing wells in the United States. The county's production volume is exceeded only by Alaska, Texas, and Louisiana. The wells in Kern County produce a unique heavy crude and some use steam injection to enhance pumping. H_2S is a problem in well fields in the county, where numerous stripper wells (defined in Chapter II) are operating. The county has a ten-person enforcement team that performs inspections at least once a year. Steam casing collection systems, valves, fittings, etc., are inspected by staff wearing H_2S monitors. Inspectors in Kern County have been exposed to H_2S in the field. In one case, an inspector was exposed to greater than 1 x 10^6 ppb. The case involved a report from a fire department station downwind of a well and complaints of odor and illness. H_2S was measured at the station at 5 x 10^4 ppb. The source was a leaking underground gas recovery line. Companies are required to keep records of such incidents and report them to CAL OSHA (personal communication, M. Amundsen, San Joaquin Unified Air District, 8/21/92).

During conversations with Kern County representatives, it was noted that an important control technology for H_2S at wells is a casing collection system, which can be added to collect natural gas containing H_2S that has built up in the casing over time. If the natural gas pressure is not relieved, well production is hindered. Companies tend to release this gas to the atmosphere, but a casing collection system can treat the gas by vapor incineration (98 to 99 percent hydrocarbon destruction efficiency). However, the economic incentive to put casing collection systems on stripper wells is normally low due to the low volume of oil produced (personal communication, M. Amundsen, A. Phillips, San Joaquin, 8/21/92).

The South Coast Air Quality Management District has no specific regulations pertaining to H_2S or oil production. Rules in place that indirectly control H_2S emissions include Rule 431.1, "Sulfur Content of Gaseous Fuels," which states that, effective May 1994, natural gas cannot be burned or sold for burning if it contains greater than 4 x 10^4 ppb total sulfur. This rule also requires organic vapor recovery systems, which would recover any H_2S gas along with the volatile organics. Rule 402 could also apply to H_2S, particularly for stripper wells that are too small for permitting. This rule is a nuisance rule that could be used to close wells if, for example, neighbors complained about H_2S odors or other health effects (personal communication, C. Bhatti, South Coast AQMD, 8/25/92). The South Coast District's enforcement program is managed as part of the Stationary Source Compliance Office, which has a staff of 500 (personal communication, C. Bhatti, South Coast AQMD, 11/23/92).

California's Occupational Safety and Health Administration is authorized to administer the Federal OSHA program. There are two OSHA standards that apply to H_2S. One focuses on the maintenance and use of valves. The second is the Permissible Exposure Limit for H_2S. It is difficult to monitor compliance with this limit because operations are outdoors. CAL OSHA maintains a database of occupational accidents. No accidents were found in the database related to H_2S releases at California oil wells dating back to 1982 (personal communication, R. Hayes, CAOSHA, 9/11/92). However, H_2S incidents were recorded in some of the Air Pollution Control Districts and Division of Oil and Gas Districts (personal communication, M. Amundsen, San Joaquin Unified Air District, 8/21/92).

The California Water Resources Control Board is generally responsible for the protection of the State's waters and for preserving all present and anticipated beneficial uses of these waters. The California Department of Health Services is responsible for the regulation of hazardous wastes. It determines which waste streams and constituents are hazardous under California's laws. The State Land Commission has joint responsibility with the Division of Oil and Gas for wells on State-owned, onshore lands.

The Office of Emergency Services administers Chapter 6.95 of the California Health and Safety Code which states that every business handling any hazardous material greater than 55 gal., 500 lb. or 200 cubic feet (gaseous material) must register and develop an emergency response plan and business plan. If the business handles extremely hazardous substances onsite exceeding threshold planning quantities (500 lb for H_2S), a preliminary analysis of the facility must be made to determine if a significant risk potential exists for accidental release of the extremely hazardous substance. If the potential does exist, the facility must develop and submit a "risk management and prevention program" that addresses how to reduce or eliminate the potential for accidental release (personal communication, Dr. F. Lercari, Office of Emergency Services, 9/13/93).

A Comparison of H_2S Regulatory Programs in Four States

Table IV-5 presents a summary of regulatory programs for H_2S across California, Michigan, Oklahoma, and Texas. This summary addresses the area of "state ... control standards, techniques, and enforcement" designated for evaluation in Section 112(n)(5) of the Clean Air Act Amendments. Appendix B tabulates components of the States' regulatory programs in greater detail.

Texas, Oklahoma, and California have H_2S ambient air quality standards in place. The California standard (30 ppb over 1-hr averaging time) is more stringent than the Texas standard (80 ppb over 0.5-hr averaging time) and the Oklahoma standard (100 ppb over 0.5-hr averaging time). Michigan does not have ambient air quality standards for H_2S.

The number of agencies in each State regulating oil and gas operations ranges from two in Oklahoma and Michigan to eleven in California. The enforcement staff, which includes inspectors and field monitoring staff, numbers 69 in Oklahoma, 215 in Texas, and 47 in Michigan. California's air emissions program is regulated by districts. The Santa Barbara District, an area with high concentrations of H_2S in its oil fields, has 10 field inspectors who are also responsible for inspecting other commercial operations. Kern County, California, has a staff of 10 field inspectors who also have other inspection responsibilities.

Michigan, Oklahoma, and Texas each have H_2S-specific regulations related to public safety. In California, State law grants the Director of the Division of Oil and Gas discretion to require additional controls (for areas such as H_2S emissions) on a case-by-case basis. However, none of the four States has specific H_2S standards in place to protect the environment, i.e., ecological protection.

Of the four States reviewed, only Texas maintains an inventory of accidental releases of H_2S from drilling and production operations. However, all four states require notification when threatening accidental releases occur. None of the four States requires reporting of H_2S routine emissions. "Routine" excludes such incidents as vapor recovery unit failures and other equipment upsets.

Texas, Oklahoma, and Michigan require worker safety training for H_2S. California's Division of Oil and Gas, however, provides guidance on worker safety in the form of a publication (Dosch and Hodgson, 1986).

Other Large Producing States

The EPA gathered initial information on several State regulations and later contacted selected State agencies to obtain additional information on the unique aspects of the State regulations governing H_2S emissions in the oil and gas industry. The results of each State review are summarized in the following sections.

Table IV-5. A Comparison of Four States' H_2S Regulatory Programs

H_2S Area	Oklahoma	Texas	Michigan	California
Ambient air quality standard?	0.10 (0.5 hr)	0.08 (0.5 hr)	No	0.03 (1 hr)
Number of State agencies regulating oil/gas	3	4	2	6
Size of enforcement/ inspection staff	69	215	47	*
Specific H_2S regulations for:				
Public Safety	Yes	Yes	Yes	No
Ecological Protection (administered by environmental agency)	No	No	Not clear	No
Inventory of accidental releases kept by State?	No	Yes	No	No
Routine reporting of emissions required?	No	No	No	No
Notification of a threatening accidental release?	Yes	Yes	Yes	Yes
H_2S training required?	Yes	Yes	Yes	Guidance

*Enforcement staff in California (example counties)

Santa Barbara County Air Pollution Control District:	10
Kern County (in San Joaquin Unified Air District):	10
California Division of Oil and Gas – District 7:	10
California Division of Oil and Gas – District 4:	9

Louisiana

Five agencies regulate oil and gas activity in Louisiana:

- Louisiana Department of Natural Resources, Office of Conservation
- Louisiana Department of Environmental Quality
- U.S. Bureau of Land Management
- U.S. Army Corps of Engineers
- U.S. Environmental Protection Agency.

The Louisiana Department of Natural Resources, Office of Conservation, regulates all subsurface and surface disposal of oil- and gas-associated wastes (*Statewide Order Governing the Drilling for the Producing of Oil and Gas in the State of Louisiana*). The office has primary responsibility for all classes of underground injection control wells. The Office of Conservation coordinates with the Louisiana Department of Environmental Quality, Office of Water Resources, on any problem dealing with discharges in the oil and gas industry. The U.S. Bureau of Land Management has jurisdiction over lease arrangements and post-lease activity on Federal lands where the mineral rights are Federally held. The Office of Conservation does not keep an emissions inventory for accidental H_2S releases. Any emissions of H_2S that exceed the Office of Conservation standard must be reported to the Office by the emitting facility.

The enforcement, field monitoring, and inspection departments of the Office of Conservation employ 34 inspectors. Emission data are sent to the Office of Conservation when an accidental release has occurred at the well site. The Office of Conservation, through administrative proceedings, can respond with the following enforcement actions when compliance is not met: compliance letters, compliance orders, civil penalty assessments, suspension/revocation of permits and pipeline severance.

In recent years, there has been no evidence of noncompliance and no emergencies involving the release of H_2S from oil or gas wells. The drilling process is not a significant threat because underground sources of H_2S are much deeper than the wells being drilled.

New Mexico

Five agencies have responsibilities for regulating oil and gas activities in New Mexico:

- New Mexico Oil Conservation Division of the Energy, Minerals and Natural Resources Department (OCD)
- New Mexico Oil Conservation Commission
- New Mexico Water Quality Control Commission
- U.S. Environmental Protection Agency

- U.S. Bureau of Land Management.

The Oil Conservation Division of the Energy, Minerals and Natural Resources Department is responsible for regulating oil and gas industry exploration and drilling, production, and refining. Its duties include regulating "nonhazardous" liquid and solid wastes from these operations to protect water quality, public health, and the environment. The Oil Conservation Commission works in conjunction with the Oil Conservation Division. The Commission initiates rules and orders to be administered by the Division. The Water Quality Control Commission develops water quality control standards and water pollution regulations. The U.S. Bureau of Land Management has jurisdiction over all Federally owned land, with the exception of Indian lands.

The Oil Conservation Division of Energy Resources (OCD) keeps emissions inventories at the district level. There are four districts in the State of New Mexico; any accidental release of H_2S must be reported to the district division of the OCD. The enforcement, field monitoring and inspection departments of the OCD employ 18 people. Inspections are made by each district OCD office. In recent years, there has been no evidence of noncompliance with the H_2S regulations set forth by the OCD, and no emergencies involving H_2S have been reported.

New Mexico's Oil Conservation Commission Rule 118 is intended to provide for the protection of the public safety in areas where H_2S concentrations greater than 1×10^5 ppb may be encountered. This rule adopts the guidance of the American Petroleum Institute publications RP 49 and RP 55 (discussed later in this chapter) and covers drilling, extraction, and abandonment.

<u>North Dakota</u>

Five agencies regulate oil and gas activities in North Dakota:

- North Dakota Industrial Commission, Oil and Gas Division
- North Dakota State Department of Health and Consolidated Laboratories
- U.S. Department of Agriculture, Forest Service
- U.S. Bureau of Land Management
- U.S. Environmental Protection Agency.

The North Dakota Industrial Commission, Oil and Gas Division, has regulatory authority over the drilling and production of oil, and is responsible for protecting the correlative rights of the mineral owners, preventing waste, and protecting all sources of drinking water. The Bureau of Land Management has jurisdiction over drilling and production on Federal lands, but the operator must obtain a permit from the Division of Oil and Gas. Drilling on forest land must comply with the rules of the U.S. Forest Service.

Any well completed or recompleted on or after July 1, 1987 must be registered with the State Department of Health and Consolidated Laboratories (NDSDH&CL). The registration process includes completion and submittal of a form which provides information about the well operator, well equipment (such as size and number of storage tanks, existence of a heater treater and type of fuel on which it is fired, flare stack height, etc.), surface equipment location, and disposition of produced gas. This form, submitted along with an analysis showing the H_2S concentration of any produced gas, constitutes registration. Information derived from the registration is entered into a shared database, which is used by the North Dakota Industrial Commission's Oil and Gas Division, for storing production data; thus, an emissions inventory which represents actual emissions can be generated from the database for all registered wells. H_2S concentrations in wellhead gas are field-pool specific; for example, within the Little Knife Oil Field, gas produced from the Madison Pool will have an H_2S concentration of approximately 9.56 percent, gas produced from the Red River Pool will be approximately 7.91 percent H_2S, and gas produced from the Duperow and Bakken pools is likely to contain only negligible amounts of H_2S. H_2S data from the registrations are, therefore, entered into the database as field-pool specific data (personal communication, D. Harman, NDSDH&CL, 5/19/93).

The enforcement, field monitoring, and inspection departments of the Division of Oil and Gas employ 14 people. The NDSDH&CL handles most of these complaint-related inspections. The Division of Oil and Gas can shut down an operation and fine up to $12,500 per day when compliance is not met. The NDSDH&CL can impose a fine and/or imprisonment.

H_2S typically constitutes between 4 and 10 percent of the oil and gas found in North Dakota. Because of this prevalence, the State has established an ambient air quality standard (shown in Table IV-1).

The NDSDH&CL typically becomes more involved in situations where routine emissions (as opposed to catastrophic/episodical releases) from a production facility result in excessive ambient concentrations. This scenario typically manifests itself in the form of citizen complaints. In these situations, it has been the Department's experience that an equipment problem, such as flare stack ignitor malfunction (i.e., low efficiency flare), storage tank gasket degradation and leakage, etc., has been the primary cause. Correction of the immediate problem and implementation of a more rigorous maintenance schedule will typically resolve these cases (personal communication, D. Harman, NDSDH&CL, 5/19/93). Acute, unpredictable releases of H_2S, such as natural gas pipeline rupture, etc., are typically handled by the North Dakota Industrial Commission; however, the Industrial Commission has had no reports of emergencies involving accidental releases of H_2S in the past two years.

Pennsylvania

Six agencies regulate oil and gas activities in Pennsylvania:

- Department of Environmental Resources,
- Bureau of Oil and Gas Management (BOGM)
- U.S. Environmental Protection Agency, Region III
- Pennsylvania Fish Commission
- U.S. Forest Service
- U.S. Bureau of Land Management.

The Bureau of Oil and Gas Management (BOGM) was created to coordinate and combine all regulatory activities of the oil and gas industry (*Oil and Gas Operators' Manual*). The U.S. Environmental Protection Agency issues permits for underground injection and secondary recovery. The Pennsylvania Fish Commission identifies pollution of surface waters and takes appropriate action under the Pennsylvania Fish and Boat Code.

The BOGM does keep records of any accidental releases; however, routine emission rates are not reported. Nearly all of Pennsylvania's H_2S problems have occurred in the northern part of the State, around Lake Erie.

The enforcement, field monitoring, and inspection departments of the BOGM employ 38 people. The Department of Environmental Resources has the following enforcement options available when compliance is not met: notice of violation, citation for summary offense, misdemeanor, civil penalty, injunction, administrative order, consent order and agreement, permit suspension and/or revocation, and bond forfeiture.

Six wells near Lake Erie have significant concentrations of H_2S that could be a threat to the surrounding environment and people. One incident in 1990 involved discharges of H_2S from a well blowout. Local authorities evacuated a neighboring town until the H_2S could be contained and the well plugged. The blowout did not cause any negative health effects or other types of injury.

In the past, Pennsylvania explored the possibility of establishing a committee that would include consultants, gubernatorial appointees, and citizens to examine H_2S in relation to the oil and gas industry and determine if a serious problem exists. It is understood that this project is currently inactive due to budget limitations.

Wyoming

There are four agencies that regulate oil and gas activities in Wyoming:

- Wyoming Oil and Gas Conservation Commission
- Wyoming Department of Environmental Quality
- U.S. Bureau of Land Management
- U.S. Environmental Protection Agency.

The Oil and Gas Conservation Commission has the general authority over oil and gas production in the State. The Department of Environmental Quality is responsible for land applications of all types of exploration and production wastes. The Bureau of Land Management is responsible for all drilling and production on Federal lands.

The Wyoming Oil and Gas Conservation Commission does keep emissions inventories on accidental releases of H_2S. Any accidental release of the gas must be reported to the Commission immediately.

The enforcement, field monitoring, and inspection departments of the Oil and Gas Conservation Commission employ ten people. The Commission has the following enforcement options when compliance is not met: civil assessments, permits denial and revocations, and bond forfeiture.

In 1989, approximately 2,982 stripper wells in Wyoming produced over 5 million barrels of oil. In recent years, there have been no signs of noncompliance; however, there have been emergencies involving accidental H_2S releases.

FEDERAL REGULATORY PROGRAMS

Current Federal regulations potentially applicable to the oil and gas production industry's handling of hydrogen sulfide are summarized below. These include regulations of the Occupational Safety and Health Administration (OSHA), Bureau of Land Management, (BLM), U.S. Geological Survey, (USGS), Superfund Amendments and Reauthorization Act (SARA) Title III, the Clean Air Act, and others. Although the OSHA standards are applicable only to workers, they are analyzed as guidelines for reducing exposure to H_2S from both accidental releases and routine emissions.

OSHA Regulations

Currently, hydrogen sulfide emissions from oil and gas exploration and drilling are not directly addressed by OSHA regulations. The regulations that are in effect to protect workers are: OSHA Standards for General Industry (29 CFR Part 1910.1000), and the respirator standards (29 CFR Part 1910.134) and the OSHA Process Safety Management Standards (listed in Chapter III). Industries in which hydrogen sulfide occurs in quantities in excess of 1500 pounds are covered in the Process Safety Management of Highly Hazardous

Chemicals Standard (29 CFR 1910.119), but retail facilities and remote, unmanned operations are exempted. Oil and gas well drilling or servicing operations are also exempted. The potential exists that oil and gas operations that are the focus of this Report to Congress may be exempt from this OSHA standard if the facility is remotely located or if servicing operations include those studied in this Report. Table IV-6 lists current and proposed regulations pertaining to hydrogen sulfide.

Current Regulations

General Industry Standards (29 CFR 1910.1000). Acceptable concentrations for chemical exposure are listed in Section 1910 under Table Z-1-A., Limits for Air Contaminants, of the General Industry Standard (1910.1000). Effective December 31, 1992, the permissible exposure limit (PEL) time weighted average (TWA) for H_2S is 1 x 10^4 ppb) (14 mg/m^3). That is, an 8-hour time weighted average, such that an employee's exposure to hydrogen sulfide in any 8-hour workshift of a 40-hour workweek, shall not exceed 1 x 10^4 ppb. Also for hydrogen sulfide, the short-term exposure limit (STEL) is 1.5 x 10^4 ppb (21 mg/m^3). The 1.5 x 10^4 ppb STEL is the employee's 15-minute (time weighted average) exposure, which shall not be exceeded at any time during the workday. The basis for the STEL is eye irritation.

The transitional OSHA standard, whose levels have been in effect since 1966, are ceiling limits and are listed in Table Z-2 of the OSHA standard. The acceptable ceiling concentration for hydrogen sulfide is 2 x 10^4 ppb, with an acceptable maximum peak above the ceiling concentration of 5 x 10^4 ppb lasting no more than 10 minutes, and occurring only once in an 8-hour shift, if no other measurable exposure occurs. The definition of a ceiling is the employee's exposure that shall not be exceeded during any part of the workday. If instantaneous monitoring is not feasible, then the ceiling shall be assessed as a 15-minute time weighted average exposure that shall not be exceeded at any time over a working day.

Respirator Standards (29 CFR 1910.134). The OSHA Personal Protective Equipment Standard (29 CFR 1910.134) outlines the types of personal protective devices (respirators) that should be worn when the ambient concentration exceeds the standards. Specific rules pertaining to hydrogen sulfide are not included in the standard. Covered in the standard are rules requiring written standard operating procedures, and employee training and screening for ability to use the equipment. Respirator selection, use, inspection and maintenance, storage, and cleaning are covered in the standard, as is air quality in supplied air respirators.

Process Safety Management of Highly Hazardous Chemicals (29 CFR 1910.119). The CAAA instructed OSHA (in section 304), in coordination with EPA, to promulgate a chemical process safety standard to prevent accidental releases of chemicals that could pose a threat to employees. This standard was finalized in February 1992 (57 *Federal Register* 6356).

The OSHA requirements for employers include standards to:

Table IV-6. Summary of Occupational Exposure Standards for H_2S

Agency/Association	Background	Standard or Guideline
Occupational Safety and Health Administration (OSHA)[a] General Industry Standards 29 CFR 1910.1000	Current: Lists acceptable concentrations for chemical exposure in the work environment. H_2S – listed under Table Z-1-A.	TWA 10 ppm 8-hour Time Weighted Average (TWA) STEL 15 ppm 15-minute Short Term 29 Exposure Limit (STEL)
OSHA Respirator Standards 29 CFR 1910.134	Current: Covers respirator selection, use, inspection and maintenance, storage and cleaning. Requires standard operating procedures; employee screening and training.	No specific rules pertaining to H_2S
OSHA Process Safety Management of Highly Hazardous Chemicals Standards 29 CFR 1910.119	Current: Remote unmanned facilities and drilling and servicing exempted. Purpose: To prevent or minimize the consequences of catastrophic releases of highly hazardous chemicals. Some elements specified by the 1990 Clean Air Act Amendments.	Threshold quantity for H_2S: 1500 pounds; meaning that the potential exists for a catastrophic accident at facilities with more than 1500 pounds on site.
OSHA Oil and Gas Well Drilling and Servicing Standards 29 CFR 1910.270	Proposed: 1983 proposal; OSHA still supports a specific standard for oil and gas production, thus their exemption from 29 CFR 1910.119 above.	Specifics pertaining to H_2S include: monitoring programs, personal protective devices, automatic flare ignitors, spark arrestors, drilling mud programs.
National Institute for Occupational Safety and Health (NIOSH)[b] Criteria Document for a Recommended Standard for Occupational Safety and Health	Recommendations for safe levels of worker exposure to H_2S. Standards developed for healthy workers, not for the public at large.	H_2S ceiling conc.: 15 mg/m^3 (approx. 1 x 10^4 ppb), 10-minute sampling, 10-hour workday, 40-hour workweek. Evacuation: 70 mg/m^3 (approx. 5 x 10^4 ppb)
American Conference of Governmental Industrial Hygienists (ACGIH)[b] Threshold Limit Values for Chemical Substances in the Work Environment	Professional organization of industrial hygienists which publishes annually updated Threshold Limit Values (TLVs) as guidelines in the control of ocupational health standards.	TLV-TWA: 1 x 10^4 ppb, for an 8-hour workday, 40-hour workweek. TLV-STEL: 1.5 x 10^4 ppb, 15-minute weighted average, not more than 4 times/dayday.

[a]Federal regulatory agency with enforceable standards; 25 of the States and territories run their own occupational safety programs.
[b]Recommended standard.

1) Develop and maintain written safety information identifying workplace chemical and process hazards, equipment, and process technology;

2) Perform a process hazard analysis which shall include an estimate of workplace effects of a range of releases and their health and safety effects on employees;

3) Consult with employees and their representatives on the conduct and development of the process safety management program.

4) Develop and implement written operating procedures for the chemical process;

5) Provide training to employees;

6) Evaluate and monitor contractor safety standards and performance;

7) Perform pre-startup safety reviews for new and modified facilities;

8) Establish maintenance systems for critical process related equipment;

9) Establish and implement written procedures to manage changes to the process;

10) Investigate every incident that has resulted or could result in a major accident;

11) Establish and implement a plant emergency action plan.

OSHA issued its final process safety standard on February 24, 1992.

Appendix A to the process safety standard (1910.119), lists the chemicals that present a potential for a catastrophic event with respective threshold quantities. For H_2S, the threshold quantity is 1500 pounds. This means that facilities with 1500 lbs or greater of H_2S on-site would be subject to the process safety management standard. OSHA further requires that the 25 States and territories with their own occupational safety organizations adopt similar rules within 6 months.

Although hydrogen sulfide is covered in this standard, oil and gas drilling or servicing operations are exempted, along with retail facilities and normally unoccupied remote facilities. OSHA explains the reason for the drilling and servicing exemptions in its preamble to the final rulemaking (57 FR 6369), stating that "OSHA continues to believe that oil and gas well drilling and servicing operations should be covered in a standard designed to address the uniqueness of the industry." This exclusion is retained in the final standard since OSHA continues to believe that a separate standard dealing with such operation is necessary. The potential exists that oil and gas operations that are the focus of this Report to Congress may be exempt form this OSHA standard if the facility is remotely located or if servicing operations include those studied in this Report. Table IV-6 lists current and proposed regulations pertaining to hydrogen sulfide.

Proposed Regulations

In 1983, OSHA proposed an Oil and Gas Well Drilling and Servicing Standard (48 FR 57202). The proposed standard would supplement the general standards already in effect and address the operation's unique hazards, such as those related to the unusual equipment, special situations dictated by the locations of operations, and hazards resulting from well pressures. According to the Bureau of Labor Statistics, the oil and gas well drilling and servicing industry was ranked among the most hazardous industries in the United States. OSHA estimated that 95,000 workers at approximately 5,400 rigs were employed in various occupations relating to oil and gas well drilling and servicing operations. The National Institute for Occupational Safety and Health (NIOSH) conducted a study of the oil and gas industry and provided OSHA with recommendations for developing a standard. In addition to a discussion of the Bureau of Labor Statistics injury data, NIOSH's "Comprehensive Safety Recommendation - Land Based Oil and Gas Well Drilling" also referenced in an early draft a study of data NIOSH received on fatalities and injuries occurring between 1973 and 1978 in Texas and California drilling operations. NIOSH applied these statistics for the entire drilling industry and concluded that the injury incidence and severity rates for the oil and gas drilling industry were more than six times the rate of general industry. However, these statistics include hazards other than H_2S.

In 1973 OSHA decided to regulate this industry under its Construction Safety Standards (29 CFR 1926); however, the applicability of this rule was contested by the industry. As a result of the industry contention, the Occupational Safety and Health Review Commission (OSHRC) ruled several times that the construction standards were not applicable. According to OSHRC, employers engaged in oil and gas well drilling and servicing should be subject to the general industry standards found in 29 CFR 1910. New enforcement problems emerged as a result of applying general industry standards. At the time of the issuance of the proposed standard, OSHA data showed that the oil and gas industry received a higher percentage of citations than any other industry. These citations are issued only when a standard does not exist to address the hazard, but the hazard is well recognized as a potential source of serious injury. OSHA felt that the high number of citations indicated the need for standards directed to these hazards in order to assist employers in meeting their obligations under the Occupational Safety and Health Act. They stated that it was apparent that the general industry standards either did not address or inadequately addressed hazards unique to oil and gas production, possibly even contributing to the higher injury and illness rate experienced by this industry. With the help of data from numerous studies of injury and illness in the oil and gas production industry, and input from numerous states, trade associations, labor unions and industry representatives, the draft oil and gas standards were proposed in 1983. No known action on this proposal has occurred since then. Currently, the proposed oil and gas well drilling and servicing rule has not been withdrawn, but it is also not on the regulatory agenda for finalizing.

OSHA proposed specific requirements for drilling, servicing, and special services operations performed in areas where a potential for exposure to H_2S gas exists. The requirements proposed establishing and implementing a monitoring program in specified areas of the rig. The monitoring program would be applicable where the potential exists for H_2S exposure, including areas where data are unavailable or inconclusive with respect to the potential H_2S exposure. The program would use automatic environmental monitoring systems connected to an employee alarm system. Details of the program and its procedures would be required from the regulated community in written form. Testing and maintenance of the monitoring system would also be regulated under the proposal, because improperly maintained or untested systems may lead to a false sense of security for employees who rely on them for warning.

Specific respiratory protection equipment requirements were also included in the proposed regulation. All employees working in an area of potential hydrogen sulfide exposure would be required to wear or carry an approved escape-type, self-contained breathing apparatus. An approved positive-pressure respirator would be required for employees who remain in or return to the danger area.

In Appendix A to the proposed rule, OSHA also suggested the following practices to control or limit hydrogen sulfide exposure:

- automatic ignitors on the flare from the degasser, choke manifold, and mud-gas separator to burn off hydrogen sulfide;
- spark arrestors for all internal combustion engines to lessen the chance of the engine serving as a source of ignition in the event of a blowout;
- regular checking of drilling mud to assure it has the right constituents and pH to counteract H_2S;
- addition of hydrogen sulfide neutralizer to the drilling mud to prevent the gas from reaching the surface;
- installation of H_2S monitoring systems on all rigs working within 1000 feet of known or suspected H_2S zones.

Although the oil and gas well drilling and servicing rule (1910.270) was proposed in 1983 and has not been enacted, OSHA has continued to express a preference for a specific regulation pertaining to the oil and gas drilling and servicing operation in 1992, by exempting these industries from the Process Safety Management of Highly Hazardous Chemicals; Explosives and Blasting Agents Final Rule (29 CFR 1910.109 and 1910.119; 57 FR 6356).

Impact of OSHA Regulations on Occupational and Human Health

OSHA regulations are designed to protect the worker rather than the general public or the environment. In this respect, they set levels that protect the health of workers exposed for a 40-hour workweek, rather than residents who may be exposed continuously. The OSHA permissible exposure limit (PEL) for H_2S is 10 ppb. Levels set to protect human health in general are often much more conservative since they are often based on models which assume exposure scenarios in which the person is exposed 24-hours a day for a lifetime. Non-occupational health effects levels may also account for possible developmental effects on young children and the effects of pollutants on those whose health is already compromised due to age or a chronic condition.

Four OSHA standards have the potential to protect workers exposed to H_2S. Two of these OSHA standards could apply to both workers and the public, while the other two apply specifically to workers. The OSHA general industry air contaminants and respirator standards protect the worker from H_2S exposures above certain levels. These standards address the protection of the worker from an exposure in excess of a set level through the use of personal protective equipment. The public is not protected through these two standards, since they aim to protect workers from contact with H_2S rather than prevent the release of the H_2S into the atmosphere. The process safety management standard and the proposed oil and gas well drilling and servicing standard have the potential to protect both the worker and the general public by preventing the release of H_2S.

National Institute for Occupational Safety and Health

Recommendations for safe levels of worker environmental exposure to H_2S are presented in the May 1977, *National Institute for Occupational Safety and Health (NIOSH) Criteria Document for a Recommended Standard for Occupational Exposure to Hydrogen Sulfide* (NIOSH, 1977). Hydrogen sulfide was cited as the leading cause of sudden death in the workplace (Ellenhorn and Barceloux, 1988). It was recognized as a serious hazard to the health of workers employed in energy production from hydrocarbon or geothermal sources, in the production of fibers or sheets from viscous syrup, in the production of deuterium oxide (heavy water), in tanneries, sewers, sewage treatment and animal waste disposal, in work below ground, fishing boats, and in chemical operations. Table IV-6 presents specific work practices recommended by NIOSH for the gas and oil industry.

A ceiling concentration was proposed to prevent eye effects and other adverse effects, including anorexia, nausea, weight loss, insomnia, fatigue, and headache, from prolonged exposure to hydrogen sulfide at low concentrations. The proposed ceiling concentration would also prevent acute eye effects, unconsciousness, and death, which can rapidly follow exposure to hydrogen sulfide at high concentrations. NIOSH suggests no employee be exposed to hydrogen sulfide at a ceiling concentration greater than 15 mg/m^3 (approximately 1×10^4 ppb), as determined with a sampling period of 10 minutes, for up to a 10-hour work shift in a 40-hour workweek. Evacuation of the area shall be required if the concentration of hydrogen sulfide equals or exceeds 70 mg/m^3 (approximately 5×10^4 ppb). NIOSH warns that the standard was not developed for the population-at-large, and any extrapolation beyond occupational exposures is not warranted.

The document includes monitoring requirements for all areas where there is occupational exposure to H_2S. First, there should be personal monitoring to detect each employee's ceiling exposure, with source and area monitoring as a supplement. The monitoring should be done quarterly, or as recommended by an industrial hygienist. Recording automatic monitors would be permitted to show short-term (less than 1-minute) peaks of up to 5×10^4 ppb, as long as no more than one occurs in any 30-minute period. These recording automatic monitors should be set up to signal spark-proof audible or visual alarms. They should have different alarms to signal concentrations of 1×10^4 ppb as an alert level to employees and 5×10^4 ppb as the level for employee evacuation.

The Secretary of Labor weighs NIOSH's recommendations, along with other considerations such as feasibility and means of implementation, in developing regulatory standards. The criteria document also contains sections on medical screening and followup of exposed employees, labeling and posting of H_2S hazards, personal protective equipment, hazard information for employees, work practices, sanitation, and monitoring and recordkeeping.

Bureau of Land Management

If a sour oil and gas well is located on Federal or Indian land, the facility operator or owner is subject to the requirements imposed by the Onshore Oil and Gas Order No. 6 developed by the Bureau of Land Management. This order requires submittal of a public protection plan by operators of sour oil and gas facilities upon detection of the potential to release a hazardous volume of H_2S (defined as concentrations of H_2S that exceed 1×10^5 parts per billion in the gas stream). Site-specific conditions are also criteria for determining whether or not a facility needs to submit a public protection plan. These conditions include (1) proximity to public buildings, public gathering centers, and roadways used for public use; and (2) radius and concentration of exposure. The order also has requirements for danger signs, fencing and gates, and wind direction indicators. Additional requirements include well control equipment, corrosion protection, and automatic safety valves or shutdowns for accidental release prevention.

The Bureau of Land Management does have procedures for enforcing Onshore Oil and Gas Order No. 6. Penalties for failure to comply with are cited in 43 C.F.R. 3163.1 (1992).

Minerals Management Service

The Minerals Management Service (Department of the Interior) Outer Continental Shelf Standard, MMS-OCS-1, Safety Requirements for Drilling Operations in a H_2S

Environment is the name for the former U.S. Geological Survey Outer Continental Shelf (OCS) Standard No.1. In February of 1976, the Conservation Division of the U. S. Geological Survey (USGS) released offshore rules for safety and pollution prevention in Standard No. 1, Safety Requirements for Drilling Operations in a Hydrogen Sulfide Environment (USGS, 1976). Required details of a contingency plan for emergency hydrogen sulfide situations are listed in the standard, and each platform is required to have the plan developed prior to drilling. The standard also specifies details of the personnel training program, and type, storage location and use of personnel protective equipment. Finally, the standard requires state-of-the-art equipment for blowout prevention, and specifies details of the mud program, well-testing procedures and flare system.

The standard requires H_2S monitoring equipment at all wells, except when drilling in areas known to be free of hydrogen sulfide. Upon encountering hydrogen sulfide, the safety requirements of the rules go into effect, and when concentrations reach 2 x 10^4 ppb the remainder of the rules dealing with hydrogen sulfide's corrosive effects must be observed. The precautions in the American Petroleum Institute Recommended Practice for Safe Drilling of Wells Containing Hydrogen Sulfide, (API RP 49) are considered supplemental to the requirements of the standard (API, 1987).

Two separate operational conditions are outlined with requirements for warning flags and notification of authorities. Moderate danger, when the threshold limit value of 10 ppm is reached, requires the display of signs and flags reading "DANGER - HYDROGEN SULFIDE - H_2S." If the concentration reaches 2 x 10^4 ppb, protective-breathing apparatus is required to be worn by all working personnel, and non-working personnel are required to evacuate to safe briefing areas. Extreme danger, when H_2S reaches the injurious level (5 x 10^4 ppb), is the point when all personnel (or all non-working personnel as appropriate) are required to evacuate. Radio communications are required to alert all known air and water craft in the immediate vicinity of the danger.

The Minerals Management Service is in the process of reproposing its standards for hydrogen sulfide.

CERCLA and EPCRA

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) of 1980 establishes broad Federal authority to deal with releases or threatened releases of hazardous substances from vessels and facilities. The Act defines a set of hazardous substances chiefly by reference to other environmental statutes; currently there are over 700 CERCLA hazardous substances. Commonly known as "Superfund," CERCLA requires that the person in charge of a vessel or facility notify the National Response Center as soon as that person has knowledge of a release of a hazardous substance in an amount equal to or greater than the reportable quantity (RQ) for that substance. Currently, hydrogen sulfide is listed as a CERCLA hazardous substance with a reportable quantity of 100 pounds.

On October 17, 1986, the President signed into law the Superfund Amendments and Reauthorization Act of 1986 (SARA), which revises and extends the authorities established under CERCLA and other laws. The Emergency Planning and Community Right-to-Know Act (EPCRA), enacted in 1986 as Title III of SARA, establishes new authorities for emergency planning and preparedness, community right-to-know reporting, and toxic chemical release reporting. It is intended to encourage and support emergency planning efforts at the State and local levels and to provide citizens and local governments with information concerning potential chemical hazards present in their communities. EPCRA is organized into three subtitles (A-C), each containing a number of subsections.

Subtitle A establishes the framework for State and local emergency planning. Section 301 requires each State to establish an emergency response commission and local emergency planning committees. Section 303 governs the development of comprehensive emergency response plans by local emergency planning committees and provision of facility information to the committee. Section 302 requires EPA to publish a list of extremely hazardous substances and threshold planning quantities (TPQs) for such substances. This list was established by EPA to identify chemical substances that could cause serious irreversible health effects from accidental releases. The list includes hydrogen sulfide, with a threshold planning quantity of 500 pounds. Any facility where an extremely hazardous substance is present in an amount in excess of the threshold planning quantity is required to notify the State commission and be included in local planning efforts. Section 304 establishes requirements for immediate reporting of certain releases of reportable quantities of extremely hazardous substances, and CERCLA Hazardous Substances, to the local planning committees and State emergency response commissions. These requirements are similar to the release reporting provisions under Section 103 of CERCLA. Section 304 also requires follow-up reports on each release, its effects, and response actions taken.

Only those sour oil and gas wells and well-site facilities that have 500 pounds or more of H_2S present at the well facility are subject to the planning requirements. The reportable quantity of H_2S is 100 pounds. Therefore, releases into the environment at or above 100 pounds must be reported in accordance with CERCLA 103 and EPCRA 304.

Subtitle B provides the mechanism for community awareness of hazardous chemicals present in the locality. This information is critical for effective local contingency planning. If the owner or operator of a facility is required to prepare or have available a Material Safety Data Sheet (MSDS) for a hazardous chemical under the Occupational Safety and Health Act of 1970 and regulations promulgated under that Act, Section 311 requires that owner or operator to submit MSDSs, or a list of the chemicals for which the facility is required to have an MSDS, to the local emergency planning committees, State emergency response commissions, and local fire departments. Under Section 312, owners and operators of facilities that must submit an MSDS under Section 311 are also required to submit chemical inventory information on the hazardous chemicals present at the facility. The threshold for reporting for H_2S under sections 311 and 312 is 500 pounds. Only facilities that have more than the threshold quantity need to report under sections 311 and 312, unless

MSDS or inventory information is specifically requested by the State Emergency Response Commission (SERC) or Local Emergency Planning Committee (LEPC). The owner or operator must submit an inventory form containing an estimate of the maximum amount of hazardous chemicals present at the facility during the preceding year, an estimate of the average daily amount of hazardous chemicals at the facility, and the location of these chemicals at the facility. Section 313 requires that certain facilities with ten or more employees that manufacture, process, or use a "toxic chemical" in excess of a statutorily-prescribed quantity submit annual information on the chemical and releases of the chemical into the environment. This information must be submitted to EPA and to the appropriate State offices annually. Hydrogen sulfide is not listed as a toxic chemical for which annual release information is required.

Subtitle C contains general provisions concerning trade secret protection, enforcement, citizen suits, and public availability of information.

Clean Air Act Section 112(r) - Accident Prevention

The Clean Air Act Amendments of 1990 established programs to prevent accidental releases of extremely hazardous substances and to assure that mitigation and response measures are in place in the event that a release does occur. Section 112(r) of the Clean Air Act establishes the responsibility for prevention of releases of extremely hazardous substances as the general duty of owners and operators of facilities that produce, process, handle or store such substances. Section 112(r) also requires that EPA promulgate a list of at least 100 substances that could cause death, injury or serious adverse effects to human health or the environment. Facilities with threshold quantities of the listed substances will be required to establish risk management programs and to prepare risk management plans. The statute requires EPA to promulgate regulations concerning risk management plans and other aspects of accident prevention. H_2S is one substance to which these requirements will apply as mandated in the statute.

The general duty clause is intended to establish as a responsibility of the facility owner the prevention of accidental releases and minimization of the consequences of accidental releases which do occur. Responsibilities include the conduct of appropriate hazard assessments and the design, operation, and maintenance of a safe facility. This means that facilities must be equipped for release mitigation and community protection should a release occur. The clause in the Clean Air Act Amendments refers to and is correlated with the general duty clause contained in the Occupational Safety and Health Act administered by OSHA. The OSHA clause was designed for situations for which there is no specific OSHA regulation or standard. Recognition of the hazard by the owner or operator, or within an industry, of the industry has been one standard under the OSHA general duty clause (U.S. Senate 1989). Therefore, the general duty clause places on the owners and operators of facilities the responsibility to adhere to applicable industry codes and standards for safety, accident prevention, and response.

The accidental release prevention list criteria include severity of acute adverse health effects, likelihood of accidental release, and potential magnitude of human exposure. A threshold quantity is to be established for each regulated substance to account for toxicity, dispersibility, reactivity, volatility, combustibility, or flammability of the substance and the amount anticipated to cause adverse health effects in an accidental release. The list and threshold quantities were proposed on January 19, 1993 (58 FR 5102). H_2S is listed as a toxic, and other substances present at oil and gas sites, such as methane, ethane, propane, and other hydrocarbons, are listed as flammables. Facilities with threshold quantities of the regulated substances will be required to prepare risk management plans (RMPs) and implement risk management programs. The RMPs will include a summary of assessments of offsite consequences for a range of accidental releases (including worst-case accidental releases) and a history of accidental releases. Facilities must also describe release prevention and emergency response programs developed under the risk management regulations as part of the RMP process.

Clean Air Act - PSD Program

There is no NAAQS which addresses hydrogen sulfide; however, emissions of H_2S are regulated under the Prevention of Significant Air Quality Deterioration (PSD) Program. PSD is designed to allow for industrial growth within specific air quality goals. The basic goals of the PSD regulations are (1) to ensure that economic growth will occur in harmony with the preservation of existing clean air resources to prevent any new nonattainment problems; (2) to protect the public health and welfare from any adverse effect which might occur even at air pollution levels better than the national ambient air quality standards; and (3) to preserve, protect and enhance the air quality in areas of special national or regional natural, recreational, scenic, or historic value, such as national parks and wilderness areas.

PSD permits are required for stationary sources located in areas designated, pursuant to section 107 of the CAA, as attainment or unclassifiable for a criteria pollutant. Major sources or modifications are those emitting either at least 100 tons per year or 250 tons per year of any pollutant regulated under the CAA, depending on the source category of the PSD listed pollutants. Major sources in nonattainment areas would be regulated under permit requirements persuant to Part D under title I of the CAA.

The CAA has set significance levels, below which a PSD permit is not required. Two tables set the significance values, one for defining significant emissions changes, in tons per year; and the other for defining significant air quality changes, in $\mu g/m^3$. For hydrogen sulfide, the applicable emissions threshold is the significant emission rate of 10 tons per year. An exemption from the monitoring provision of the permitting regulations for hydrogen sulfide is set as a 1-hour average concentration of 0.02 $\mu g/m^3$. Hydrogen sulfide emissions are also counted as part of the Total Reduced Sulfur and Reduced Sulfur, both having significance values set at 10 tons per year. These pollutant classes are regulated primarily to avoid nuisance (odor) problems.

The applicability of the PSD permit program to oil and gas extraction wells would be dependent on the amount of emissions and the grouping of the wells (i.e., whether several wells would be combined for calculation of emissions). In general, it appears that most oil and gas extraction wells would not likely be subject to PSD regulations based on the applicability criteria.

INDUSTRY-RECOMMENDED SAFETY AND ENVIRONMENTAL PROTECTION PROCEDURES

This section summarizes selected industry standards and practices for managing H_2S releases to the atmosphere. The American Petroleum Institute (API) has developed and published design, construction, and operating standards. Certain aspects of these standards pertaining to accidental release prevention were discussed in the previous chapter.

API Recommended Practices

The American Petroleum Institute (API), an industry-wide technical organization, has published several recommended practices (RP) pertaining to hydrogen sulfide in the oil and gas production industry. These voluntary guidelines are intended to maintain worker and public safety and health. Table IV-7 lists API Recommended Practices pertinent to production and operations in formations containing H_2S.

Control Standards

API RP 49, Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide (April 15, 1987) and API RP 55, Recommended Practices for Conducting Oil and Gas Production Operations Involving Hydrogen Sulfide (October 1981; reissued March, 1983; and preparation of a second edition began in 1990) are the two main documents dealing with H_2S in oil and gas production. It is expected that the revised RP 55 will provide information similar in scope to that in the document currently under revision, but with additional detail and more current references. These recommended practices do not set a control level for H_2S emissions; rather they identify situations to which the practices apply. They are applicable in oil and gas operations where the potential exists for atmospheric concentrations of H_2S to reach 2×10^4 ppb. They also apply "where the fluids handled contain sufficient H_2S to produce a partial pressure above 0.05 pounds per square inch absolute (psia) and the total pressure is 65 psia or greater, or where internal or external stresses are present which could result in pipe or equipment failure due to sulfide stress cracking and/or hydrogen embrittlement" (API, 1987). In these cases, materials must meet National Association of Corrosion Engineers (NACE) standards.

Control Techniques

The control techniques discussed in the API Recommended Practices take two approaches to worker and public safety. First, when hydrogen sulfide has already been

Table IV-7. **Reviewed American Petroleum Institute* Documents Pertaining to H_2S in Oil and Gas Production**

Document	Date	Title	Topics Covered
Recommended Practice 49 (RP49)	2nd Edition April 15, 1987	Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide	Personnel training and protective equipment. Locations. Rig and well equipment. Rig operations in H_2S environments. Contingency planning and emergency procedures. Properties and effects of H_2S and SO_2. Sour environment definition.
Recommended Practice 51 (RP51)	1st Edition October 1974 Reissued May 1982	API Recommended Onshore Production Operating Practices for Protection of the Environment	Producing wells. Lease roads, gathering systems and pipelines. Production and water handling facilities. Oil discharge – prevention and cleanup.
Recommended Practice 53 (RP53)	2nd Edition May 25, 1984	Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells	Arrangement (surface and subsea) and/or installation of: blowout preventers, choke and kill units and lines, closing units, auxilliary equipment, pipe stripping, marine riser systems. Inspection and testing. Sealing components. Blowout modifications for H_2S environments.
Recommended Practice 54 (RP54)	2nd Edition May 1, 1992	Recommended Practices for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations	Injuries and first aid. Protective equipment. Fire prevention. Drilling and well servicing rig equipment and electrical systems. Wireline service. Stripping and snubbing. Drill stem testing. Operations (including H_2S environment).
Recommended Practice 55 (RP55)	1st Edition October 1981 Reissued March 1983 (revision in progress)	Recommended Practices for Conducting Oil and Gas Production Operations Involving Hydrogen Sulfide	Personnel training and protective equipment. Contingency plans and emergency procedures. Design, construction, and operating procedures. Surveillance and maintenance. Continuous H_2S monitoring equipment. Supplementary guidance and reference material for H_2S operations.
Specification 6A (SPEC 6A)	16th Edition October 1, 1989	Specification for Wellhead and Christmas Tree Equipment, Supplement 1 and 2	Design and performance. Materials. Welding. Quality control. Equipment marking, shipping, storing, and specific requirements.

*American Petroleum Institute; 1220 L Street, Northwest; Washington, DC 20005.

released, worker and public safety is protected through the use of monitoring programs, personal protective devices and contingency plans for evacuations. Second, the engineering approach uses design, construction, and operating procedures to prevent the release of hydrogen sulfide to the atmosphere. The prevention of equipment damage due to corrosion (sulfide stress cracking) and the techniques for prevention of blowouts in API RP 53, Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells, are two main considerations in this more site- specific engineering control technique.

API RP 49, which deals with drilling in a hydrogen sulfide environment, contains the following recommendations for well siting in order to protect workers from the effects of hydrogen sulfide accumulation at the well site: "Rig components should be arranged on a location such that prevailing winds blow across the rig in a direction that will disperse any vented gas from the areas of the wellhead, choke manifold, flare stack or line, mud/gas separator, drilling fluid tanks, reserve pits, shale shaker, and degasser away from any potential ignition source (i.e., engines, generators, compressors, crew quarters, etc.) and areas used for personnel assembly. All equipment should be located and spaced to take advantage of prevailing winds and to provide for good air movement to eliminate as many sources of potential gas accumulation as possible" (API, 1987).

Other siting recommendations in API RP 49, shown in Figure III-4, are the use of caution signs at entrance and exit roads to warn of hydrogen sulfide concentrations above 2×10^4 ppb and danger flags to warn of extreme danger when the concentration exceeds 5×10^4 ppb. These signs are required to stay in place when flaring of the hydrogen sulfide could produce sulfur dioxide concentrations in excess of 5×10^3 ppb. Protection or briefing centers should be placed upwind or perpendicular to the prevailing wind, with wind direction indicators easily visible from the briefing location and all work locations. Mechanical ventilation, large fans or bug blowers, should be available for use during light wind conditions to prevent the hydrogen sulfide from accumulating in low lying locations. The locations of drilling fluid systems, power plants, burn pits, and flare stacks are also discussed from the vantage point of worker safety after the release of hydrogen sulfide.

Both API RP 49 (pertaining to drilling in a hydrogen sulfide environment) and API RP 55 (dealing with production operations) contain recommendations for personnel training. RP 55 training program topics include: the effects upon humans of various concentrations of hydrogen sulfide; protective equipment, including the use of self contained breathing apparatus rather than canister type gas masks (a filtering type mask is not appropriate for protection from hydrogen sulfide); monitoring devices; emergency procedures; material selection; and the importance of ventilation. Monitoring equipment that would set off a visual alarm at 1×10^4 ppb and an audible one at 2×10^4 ppb is recommended. Breathing equipment requirements are also discussed, including selection and storage (where they are readily available in an emergency).

Contingency plans are outlined in Section 4 of API RP 55 (API, 1983). They are recommended for each operation that has the potential for an accidental release capable of exposing the public to hazardous concentrations of hydrogen sulfide. Contingency plans should include the locations of: equipment that contains hydrogen sulfide, residences and other public facilities, evacuation routes, safety equipment, telephones, and designated briefing areas for employees. The contingency plan should also include procedures for calculating the dispersion of releases and lists of emergency telephone numbers. Finally, it is suggested that public and local officials should be briefed about the potential hazard prior to an incident, and that periodic tests of the contingency plan should be conducted.

RP 55 also covers protection of workers from the toxic effects of hydrogen sulfide due to build-up of gas concentration in confined areas. Protective equipment or purging is recommended for vessels that have previously held hydrogen sulfide. Extreme caution should be used when entering buildings containing equipment used to handle fluids containing hazardous concentrations of hydrogen sulfide. Routine use of personal protective devices is suggested in these instances.

API RP 54, Recommended Practices for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations (May 1, 1992) also addresses some aspects of personal protection from the toxic effects of hydrogen sulfide (API, 1992). This document was released after OSHA's implementation of the 1×10^4 ppb time-weighted average standard. RP 54 does not mention any specific standard or level, rather it refers the reader back to API RP 49 and API RP 55, which state that they apply to oil and gas operations where the potential exists for atmospheric concentrations to reach 2×10^4 ppb (the old OSHA ceiling standard), or where the gas could cause corrosion of the equipment. API does caution throughout their documents that the latest local, State and Federal regulations should be consulted.

Engineering controls used to prevent the production of, or the release of, hydrogen sulfide to the atmosphere are covered in the recommended practices for drilling and production (RP 49 and RP 55). API RP 55, pertaining to production, warns of the potential for introducing sulfur-reducing bacteria, which produce hydrogen sulfide, into a formation during pressure maintenance or water flooding operations (i.e., enhanced oil recovery). Operators are warned to be aware of the possibility and to act quickly if introduction occurs. If care is taken to prevent the bacteria from being introduced into formations that do not contain hydrogen sulfide, the danger of hydrogen sulfide pollution will be prevented.

Other engineering controls such as those used in design, construction, and operating practices are covered in Section 5 of RP 55. API recommends that construction materials meet specifications of the National Association of Corrosion Engineers (NACE) Standard MR-01-75: Material Requirements for Sulfide Stress Cracking Resistant Metallic Material for Oil Field Equipment. These materials include all those that are exposed to fluids containing hydrogen sulfide and critical to its containment. Process factors for consideration are discussed, including the concentration of hydrogen sulfide, the maximum atmospheric temperatures expected, pressure, pH, water content of fluids, mechanical stresses, corrosional or scale effects on the system, and any others unique to each situation. Finally, piping design should eliminate dead or slow-flow areas where fluids containing hydrogen sulfide gas can collect.

Drilling fluids are important to the control of the drilling environment. According to API RP 49 (Recommended Practices for Safe Drilling of Wells Containing Hydrogen Sulfide), the following practices help to maintain environmental control: maintenance of a pH of 10 or higher to neutralize hydrogen sulfide (failing to maintain proper pH can cause release of hydrogen sulfide from the drilling fluid system), the use of chemical sulfide scavengers, and the use of oil-based drilling fluids. When hydrogen sulfide gas is breaking out of drilling fluids, the fluids should be routed through a mud-gas separator until the level is reduced to a safe one. Corrosion inhibitors that create a film which protects the equipment from pitting and eventual sulfide stress cracking are also recommended. Finally, extreme caution is urged in storing fluids that have been exposed to hydrogen sulfide, and in entering enclosed areas where drilling fluids have been stored.

Drill stem, casing, tubing, and wellhead selection must meet specifications of API, NACE, the American Society of Mechanical Engineers, and the American National Standards Institute, detailed in Section 5 of RP 49. Section 5 also covers procedures for limited entry tests and equipment considerations for blowout preventer units, closing units, remote choke control lines, and kill lines. Hydrogen sulfide considerations in mud/gas separators, degassers and flare system are also discussed.

Abandonment procedures are included in API RP 55, with the disclaimer that the suggested procedures do not supersede local, State or Federal regulations. Section 6.5 discusses spontaneous combustion of iron sulfide, which is produced by the reaction of H_2S with steel. Because spontaneous combustion is possible when iron sulfide is exposed to air, RP 55 suggests that iron sulfide be kept wet until it can be burned or buried. Iron sulfide also poses a hazard during well servicing operations. Acids react with the iron sulfide to produce H_2S. Damage may also occur in pipes exposed alternately to hydrogen sulfide and air. API stresses the use of monitoring equipment when well servicing operations are performed on wells where a hydrogen sulfide hazard exists.

Hydrogen sulfide in oil and gas production is also mentioned in API RP 51, API Recommended Onshore Production Operating Practices for Protection of the Environment (October 1974, reissued May 1982). General information on the protection of personnel and equipment are presented in this document (API, 1982).

FINDINGS

1. Eighteen States have short-term H_2S ambient air quality standards. Four of the nine major oil and gas producing States reviewed in this report do not have ambient air standards.

2. Ambient air quality standards range from 160 ppb per 24 hr average time to 50 ppb per 0.5 hr average time.

3. The number of State agencies involved in controlling oil and gas operations varies widely.

4. The size of enforcement staffs at the State level varies greatly, with some staff having inspection responsibility beyond oil and gas operations.

5. No specific H_2S environmental (i.e., ecological) protection standards were found for Texas, Michigan, Oklahoma and California.

6. Not all States maintain notification requirements for accidental releases of H_2S from oil and gas wells. Some do require notification when a threatening accidental release occur.

7. Reporting of routine H_2S emissions is not required in Texas, Oklahoma, Michigan, or California. "Routine" excludes such incidents as vapor recovery unit failures and other equipment upsets.

8. NIOSH suggests no employee be exposed to H_2S at a ceiling concentration greater than 15 mg/m^3 (about 1×10^4 ppb) for up to a 10 hr work shift in a 40 hr work week. Evacuation is required if the concentration equals or exceeds 70 mg/m^3 (5×10^4 ppb).

9. NIOSH requires monitoring in work areas with alarms sounding at 1×10^4 ppb and 5×10^4 ppb.

10. The Minerals Management Service requires for offshore rigs drilling in an H_2S environment: contingency plan, personnel training, state-of-the-art blowout prevention equipment, monitoring equipment and response procedures at 1×10^4, 2×10^4, and 5×10^4 ppb. Special mud programs, well-testing procedures, and flare systems are also required. This Federal regulatory program does not have an equivalent onshore program.

11. The PSD permit program applies to significant emissions of H_2S from new sources emitting greater than 250 tons per year (or 100 tons per year for certain source categories) of any regulated pollutant, i.e., major PSD sources. It also applies to modifications of existing facilities if the net emissions increase of H_2S from the modification is significant. In either case, the significant emission rate for H_2S is 10 tons per year. Also, permits do not require monitoring if the 1-hr average concentration is below 0.014 ppb (0.02 μg/m^3). H_2S is also regulated under the PSD program for its nuisance odor as part of a larger group of Total Reduced Sulfur and Reduced Sulfur (significant $\geq$ 10 tons/yr).

12. Accidental releases of H_2S can be prevented by application of process safety management principles. The following are among the ways that these principles are adopted:

    a. Under the Clean Air Act, as amended, industry has a responsibility to identify hazards, take the actions necessary to prevent chemical accidents, and to take action to mitigate accidents in the event that they do occur.
    b. OSHA has promulgated a process safety management standard that requires facilities to implement process safety management programs for chemicals including H_2S to protect workers from accidents. These same measures can also prevent chemical accidents that might affect the public. However, the OSHA requirements do not apply to remote or unstaffed facilities such as most oil and gas well sites.
    c. Under the Clean Air Act, as amended, EPA must promulgate rules that require facilities handling H_2S to implement a risk management plan designed to prevent chemical accidents that adversely affect the public.
    d. The Bureau of Land Management's Onshore Oil and Gas Order No. 6 addresses the prevention of accidental releases of H_2S on Federal or Indian lands.
    e. Several State programs address the prevention of accidental releases of H_2S. States with such programs include Oklahoma, Texas, Michigan, California, and New Mexico.
    f. Voluntary industry initiatives (e.g., codes, standards, recommended practices) such as the API RP 55, Recommended Practices for Conducting Oil and Gas Operations Involving H_2S, which is currently being revised, have been implemented by many facilities.

13. A number of Federal and State requirements exist for emergency planning in the event that an accidental release of H_2S occurs.

    a. Facilities handling quantities of H_2S greater than threshold amounts are subject to the emergency planning requirements of the Emergency Planning and Community Right-to-Know Act (EPCRA).
    b. The accidental release prevention provisions of the Clean Air Act Amendments will require facilities handling amounts of H_2S above threshold quantities to implement an emergency response program.
    c. For Federal and Indian lands, the Bureau of Land Management requires public protection plans for sour oil and gas production operations that meet certain criteria.
    d. Several States require contingency plans in the event of accidental H_2S releases. State requirements include those of Oklahoma, Texas, Michigan, California, and New Mexico.

e. API RP 55 recommends that contingency plans be developed for oil and gas extraction facilities where an accidental release of H_2S could be immediately hazardous to life or health.

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CHAPTER V
RECOMMENDATIONS

ROUTINE EMISSIONS

From the limited data available, there appears to be no evidence that a significant threat to public health or the environment exists from routine H_2S emissions from sour oil and gas extraction. States and industry are encouraged to evaluate existing design, construction, and operation principles within the framework of process safety management. EPA recommends no further legislation pertaining to routine H_2S emissions from oil and gas extraction at this time.

ACCIDENTAL RELEASES

General

The EPA recommends no further legislative action pertaining to accidental H_2S releases from oil and gas extraction activities at this time. The regulations already promulgated, and being developed, under the authorities provided to EPA in CERCLA, EPCRA, and the accidental release prevention provisions of the CAA, provide a good framework for the prevention of accidental releases and preparedness in the event that they occur.

- EPA should track implementation of current and future industry standards and recommended practices at sour oil and gas extraction facilities. An example of such industry standards is the American Petroleum Institute Recommended Practices for Conducting Oil and Gas Production Operations Involving Hydrogen Sulfide (API RP55). EPA should consider outreach specifically directed at non-participating sectors.

- The EPA should participate in the investigation of any accidental releases associated with H_2S that cause or have the potential to cause public impacts in order to determine the root cause of such accidents. Such investigations should be coordinated with the Occupational Safety and Health Administration (OSHA) in order to encompass worker safety issues.

- The EPA should continue to investigate the need for additional rulemaking under the accidental release prevention provisions of the Clean Air Act to require implementation of certain prevention, detection, monitoring and mitigation efforts at facilities where extremely hazardous substances (such as H_2S) could generate dense gas clouds and impact the public.. The level of voluntary industry initiatives and degree of participation, and accident history should be taken into account.

Facility and Local Emergency Planning Committee (LEPC)

Facilities that handle hazardous substances that could form dense vapor clouds if accidentally released, such as H_2S, should work closely with their LEPC to prevent accidents and to be prepared to respond to such accidents.

- Facilities should identify and thoroughly understand the hazards and conditions that can lead to accidental releases and the potential impacts on the public. These hazards and potential impacts should be communicated to the LEPC.

- All sour oil and gas extraction facilities and the LEPC for that area should conduct drills and exercises with workers, the community, first responders and others to test mitigation, response, and medical treatment for a simulated major H_2S accident. All such facilities should have training programs in place for H_2S emergencies.

Preparedness and Response

All sour oil and gas extraction facilities should actively conduct outreach efforts to ensure that the community is aware of the hazards of H_2S, that protective measures are in place to prevent public health impacts, and that proper actions will be taken during an emergency. Such outreach should be conducted through the LEPCs.

- All sour oil and gas extraction facilities should able to rapidly detect, mitigate, and respond to accidental releases in order to minimize the consequences. Site-specific risk factors should be taken into account.

- Because a general duty exists to design, operate, and maintain a safe facility, owners and operators of sour oil and gas facilities should use appropriate equipment for the facility to provide public safety and should implement a program to remedy the effects of wear and tear and corrosion on equipment.

- In addition to regular inspection of all equipment, owners and operators should pay particular attention to corrosion monitoring of existing flow and gathering lines and to the condition of temporarily abandoned equipment. Remedial action should be taken before accidental releases occur.

- EPA should foster the development and continued refinement of release detection and mitigation systems for hazardous substances, such as H_2S, in order to improve their reliability and effectiveness.

- All facilities that handle oil and gas with potentially harmful levels of H_2S should have proper medical treatment supplies and trained personnel available and should ensure that first responders, hospitals, and clinics in the area are prepared to treat H_2S exposure.

Research and Further Studies

- Further study on the acute exposure levels of H_2S that result in irreversible health effects or lethality in humans should be continued in order to improve emergency planning tools such as atmospheric dispersion models.

- Further research on the effects of surface roughness and obstacles on dense-gas dispersion behavior should be continued to determine their influences on toxic substance concentrations in a dispersing vapor cloud. The Liquefied Gaseous Fuels Spill Test Facility could be used for spill tests to assist in this research.

- EPA should continue to study the issues surrounding worst-case releases, their consequences, and the likelihood of worst-case or other significant releases for extremely hazardous substances and the role and relationship of these issues to prevention, preparedness, and response.

GLOSSARY

Abandon: To cease producing oil or gas from a well when it becomes unprofitable. A wildcat may be abandoned after it has been proven nonproductive. Usually, before a well is abandoned, some of the casing is removed and salvaged and one or more cement plugs are placed in the borehole to prevent migration of fluids between the various formations. In many States, wells may not be abandoned unless approved by an official regulatory agency.

Accidental Release: The unanticipated emissions of a regulated substance or other extremely hazardous substance into the air from a stationary source.

Acid: Any chemical compound, one element of which is hydrogen, that dissociates in solution to produce free-hydrogen ions. For example, hydrochloric acid, HCl, dissociates in water to produce hydrogen ions, H^+, and chloride ions, Cl^-.

Additive: A substance or compound added in small amounts to a larger volume of another substance to change some characteristic of the latter. In the oil industry, additives are used in lubricating oil, fuel, drilling mud, and cement for cementing casing.

Air drilling: A method of rotary drilling that uses compressed air as its circulation medium. This method of removing cuttings from the wellbore is as efficient or more efficient than the traditional methods using water or drilling mud; in addition, the rate of penetration is increased considerably when air drilling is used. However, a principal problem in air drilling is the penetration of formations containing water, since the entry of water into the system reduces its efficiency.

Alkalinity: The combining power of a base, or alkali, as measured by the number of equivalents of an acid with which it reacts to form a salt.

Annular injection: Long-term disposal of wastes between the outer wall of the drill stem or tubing and the inner wall of the casing or open hole.

Annulus or annular space: The space around a pipe in a wellbore, the outer wall of which may be the wall of either the borehole or the casing.

API: The American Petroleum Institute. Founded in 1920, this national oil trade organization is the leading standardizing organization on oil-field drilling and production equipment. It maintains departments of transportation, refining, and marketing in Washington, D.C., and a department of production in Dallas.

Artificial lift: Any method used to raise oil to the surface through a well after reservoir pressure has declined to the point at which the well no longer produces by means of natural energy. Artificial lift may also be used during primary recovery if the initial reservoir pressure is inadequate to bring the hydrocarbons to the surface. Sucker-rod pumps, hydraulic pumps, submersible pumps, and gas lift are the most common methods of artificial lift.

Barrel (bbl): A measure of volume for petroleum products. One barrel (1 bbl) is equivalent to 42 U.S. gallons or 158.97 liters. One cubic meter (1 m^3) equals 6.2897 bbl.

Basin: A synclinal structure in the subsurface, formerly the bed of an ancient sea. Because it is composed of sedimentary rock and its contours provide traps for petroleum, a basin is a good prospect for exploration. For example, the Permian Basin in West Texas is a major oil producing area.

Bit: The cutting or boring element used in drilling oil and gas wells. Most bits used in rotary drilling are roller-cone bits. The bit consists of the cutting element and the circulating element. The circulating element permits the passage of drilling fluid and uses the hydraulic force of the fluid stream to improve drilling rates. In rotary drilling, several drill collars are joined to the bottom end of the drill-pipe column for added weight. The bit is attached to the end of the drill collar.

Blowdown: The emptying or depressurizing of a material from a vessel. The material thus discarded.

Blowout preventer (BOP): Equipment installed at the wellhead, at surface level on land rigs and on the seafloor of floating offshore rigs, to prevent the escape of pressure either in the annular space between the casing and drill pipe or in an open hole during drilling and completion operations.

Blow out: To suddenly expel oil-well fluids from the borehole with great velocity. To expel a portion of water and steam from a boiler to limit its concentration of minerals.

Borehole: The wellbore; the hole made by drilling or boring.

Casing: Steel pipe placed in an oil or gas well as drilling progresses to prevent the wall of the well from caving in during drilling and to provide a means of extracting petroleum if the well is productive.

Casing string: Casing is manufactured in lengths of about 30 ft, each length or joint being joined to another as casing is run in a well. The entire length of all the joints of casing is called the casing string.

Cement: A powder consisting of alumina, silica, lime, and other substances which hardens when mixed with water. Extensively used in the oil industry to bond casing to the walls of the wellbore.

Cement plug: A portion of cement placed at some point in the wellbore to seal it.

Christmas tree: Assembly of fittings and valves at the tip of the casing of an oil well that controls the flow of oil from the well.

Close-in: A well capable of producing oil or gas, but temporarily not producing.

Collar: A coupling device used to join two lengths of pipe. A combination collar has left-hand threads in one end and right-hand threads in the other. A drill collar.

Commercial production: Oil and gas output of sufficient quantity to justify keeping a well in production.

Completion fluid: A special drilling mud used when a well is being completed. It is selected not only for its ability to control formation pressure, but also for its properties that minimize formation damage.

Completion operations: Work performed in an oil or gas well after the well has been drilled to the point at which the production string of casing is to be set. This work includes setting the casing, perforating, artificial stimulation, production testing, and equipping the well for production. It is done prior to the commencement of the actual production of oil or gas in paying quantities, or in the case of an injection or service well, prior to when the well is plugged and abandoned.

Corrosion: A complex chemical or electrochemical process by which metal is destroyed through reaction with its environment. Rust is an example of corrosion.

Crude oil: Unrefined liquid petroleum. It ranges in gravity from 9° to 55° API and in color from yellow to black, and it may have a paraffin, asphalt, or mixed base. If a crude oil, or crude, contains a sizable amount of sulfur or sulfur compounds, it is called a sour crude; if it has little or no sulfur, it is called a sweet crude. In addition, crude oils may be referred to as heavy or light according to API gravity, the lighter oils having the higher gravities.

Cuttings: The fragments of rock dislodged by the bit and brought to the surface in the drilling mud. Washed and dried samples of the cuttings are analyzed by geologists to obtain information about the formations drilled.

Demulsify: To resolve an emulsion, especially of water and oil, into its components.

Desander: A centrifugal device used to remove fine particles of sand from drilling fluid to prevent abrasion of the pumps. A desander usually operates on the principle of a fast-moving stream of fluid being put into a whirling motion inside a cone-shaped vessel.

Desilter: A centrifugal device, similar to a desander, used to remove very fine particles, or silt, from drilling fluid to keep the amount of solids in the fluid to the lowest possible level. The lower the solids content of the mud, the faster the rate of penetration.

Disposal well: A well into which salt water is pumped; usually part of a saltwater-disposal system.

Drill: To bore a hole in the earth, usually to find and remove subsurface formation fluids such as oil and gas.

Drill collar: A heavy, thick-walled tube, usually steel, used between the drill pipe and the bit in the drill stem to weight the bit in order to improve its performance.

Drill cutting: The formation rock fragments that are created by the drill bit during the drilling process.

Drilling fluid: The circulating fluid (mud) used in the rotary drilling of wells to clean and condition the hole and to counterbalance formation pressure. A water-based drilling fluid is the conventional drilling mud in which water is the continuous phase and the suspended medium for solids, whether or not oil is present. An oil-based drilling fluid has diesel, crude, or some other oil as its continuous phase with water as the dispersed phase. Drilling fluids are circulated down the drill pipe and back up the hole between the drill pipe and the walls of the hole, usually to a surface pit. Drilling fluids are used to lubricate the drill bit, to lift cuttings, to seal off porous zones, and to prevent blowouts. There are two basic drilling media: muds (liquid) and gases. Each medium comprises a number of general types. The type of drilling fluid may be further broken down into numerous specific formulations.

Drill pipe: The heavy seamless tubing used to rotate the bit and circulate the drilling fluid. Joints of pipe 30 ft long are coupled together by means of tool joints.

Drill site: The location of a drilling rig.

Drill stem: The entire length of tubular pipes, composed of the kelly, the drill pipe, and drill collars, that make up the drilling assembly from the surface to the bottom of the hole.

Drill string: The column, or string, of drill pipe, not including the drill collars or kelly. Often, however, the term is loosely applied to include both the drill pipe and drill collars.

Emulsion: A mixture in which one liquid, termed the dispersed phase, is uniformly distributed (usually as minute globules) in another liquid, called the continuous phase or dispersion medium. In an oil-water emulsion, the oil is the dispersed phase and the water the dispersion medium; in a water-oil emulsion the reverse holds. A typical product of oil wells, water-oil emulsion also is used as a drilling fluid.

Embrittlement: Through chemical reactions with H_2S, steel and other materials become more brittle and more likely to break.

Emulsion breaker: A system, device, or process used for breaking down an emulsion and rendering it into two or more easily separated compounds (like water and oil). Emulsion breakers may be (1) devices to heat the emulsion, thus achieving separation by lowering the viscosity of the emulsion and allowing the water to settle out; (2) chemical compounds, which destroy or weaken the film around each globule of water, thus uniting all the drops; (3) mechanical devices such as settling tanks and wash tanks; or (4) electrostatic treaters, which use an electric field to cause coalescence of the water globules. This is also called electric dehydration.

Enhanced oil recovery (EOR): A method or methods applied to depleted reservoirs to make them productive once again. After an oil well has reached depletion, a certain amount of oil remains in the reservoir, which enhanced recovery is targeted to produce. EOR can encompass secondary and tertiary production.

EPA: United States Environmental Protection Agency.

Exploration: The search for reservoirs of oil and gas, including aerial and geophysical surveys, geological studies, core testing, and the drilling of wildcats.

Extraction: The physical removal of oil and gas from a well.

Field: A geographical area in which a number of oil or gas wells produce from a continuous reservoir. A field may refer to surface area only or to underground productive formations as well. In a single field, there may be several separate reservoirs at varying depths.

Flare: Combustion of wastegases, such as H_2S or natural gas, which are not able to be profitably brought to market.

Flowing well: A well that produces oil or gas without any means of artificial lift.

Formation: A bed or deposit composed throughout of substantially the same kinds of rock; a lithologic unit. Each different formation is given a name, frequently as a result of the study of the formation outcrop at the surface and sometimes based on fossils found in the formation.

Gas plant: A plant for the processing of natural gas, by other than solely mechanical means, for the extraction of natural gas liquids, and/or the fractionation of the liquids into natural gas liquid products such as ethane, butane, propane, and natural gasoline.

Heater-treater: A vessel that heats an emulsion and removes water and gas from the oil to raise it to a quality acceptable for pipeline transmission. A heater-treater is a combination of a heater, free-water knockout, and oil and gas separator.

Hydrocarbons: Organic compounds of hydrogen and carbon, whose densities, boiling points, and freezing points increase as their molecular weights increase. Although composed of only two elements, hydrocarbons exist in a variety of compounds because of the strong affinity of the carbon atom for other atoms and for itself. The smallest molecules of hydrocarbons are gaseous; the largest are solid.

Ignitability (RCRA): The hazardous characteristic of ignitability for purposes of RCRA is defined in 40 CFR 261.21 and is generally a liquid with a flash point less than 140 degrees F., a non-liquid that causes fire under a friction condition, an ignitable compressed gas, or is an oxidizer.

Inhibitor: An additive used to retard undesirable chemical action in a product. It is added in small quantities to gasolines to prevent oxidation and gum formation, to lubricating oils to stop color change, and to corrosive environments to decrease corrosive action.

Injection well: A well in which fluids have been injected into an underground stratum to increase reservoir pressure.

Kelly: A pipe attached to the top of a drill string and turned during drilling. It transmits twisting torque from the rotary machinery to the drill string and ultimately to the bit.

LC_{50} (median lethal concentration): The concentration of a chemical required to cause death in 50% of the exposed population when exposed for a specified time period, and observed for a specified period of time after exposure. Refers to inhalation exposure concentration in the context of air toxics (may refer to water concentration for tests of aquatic organisms or systems).

Lease: A legal document executed between a landowner (or a lessor) and a company or individual, as lessee, that grants the right to exploit the premises for minerals or other products. The area where production wells, stock tanks, separators, and production equipment are located.

Lowest-observed-adverse-effect level (LOAEL): The lowest dose or exposure level of a chemical in a study at which there is a statistically or biologically significant increase in the frequency or severity of an adverse effect in the exposed population as compared with an appropriate, unexposed control group.

Mud: The liquid circulated through the wellbore during rotary drilling and workover operations. In addition to its function of bringing cuttings to the surface, drilling mud cools and lubricates the bit and drill stem, protects against blowouts by holding back subsurface pressures, and deposits a mud cake on the wall of the borehole to prevent loss of fluids to the formation. Although it originally was a suspension of earth solids (especially clays) in water, the mud used in modern drilling operations is a more complex, three-phase mixture of liquids, reactive solids, and inert solids. The liquid phase may be fresh water, diesel oil, or crude oil and may contain one or more conditioners.

Natural gas: Naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface. The principal hydrocarbon constituent is methane.

No-observed-adverse-effect level (NOAEL). The highest experimental dose at which there is no statistically or biologically significant increases in frequency or severity of adverse health effects, as seen in the exposed population compared with an appropriate, unexposed population. Effects may be produced at this level, but they are not considered to be adverse.

Odor perception threshold: The lowest concentration at which a substance is first able to be smelled.

Oil base muds: A drilling fluid that is a water-oil emulsion with oil as the continuous phase. The oil content ranges from 50-98% oil. Oil muds are used to reduce drilling torque and to stabilize reactive shales that impede the drilling process.

Oil and gas separator: An item of production equipment used to separate the liquid components of the well stream from the gaseous elements. Separators are vertical or horizontal and are cylindrical or spherical in shape. Separation is accomplished principally by gravity, the heavier liquids falling to the bottom and the gas rising to the top. A float valve or other liquid-level control regulates the level of oil in the bottom of the separator.

Oil field: The surface area overlying an oil reservoir or reservoirs. Commonly, the term includes not only the surface area but also the reservoir, wells, and production equipment.

Operator: The person or company, either proprietor or lessee, actually operating an oil well or lease.

Packer: A piece of downhole equipment, consisting of a sealing device, a holding or setting device, and an inside passage for fluids. It is used to block the flow of fluids through the annular space between the tubing and the wall of the wellbore by sealing off the space. The packer is usually made up in the tubing string some distance above the producing zone. A sealing element expands to prevent fluid flow except through the inside bore of the packer and into the tubing. Packers are classified according to configuration, use, and method of setting and whether or not they are retrievable (i.e., whether they can be removed when necessary, or whether they must be milled or drilled out and thus destroyed).

Perforate: To pierce the casing wall and cement to provide holes through which formation fluids may enter, or to provide holes in the casing so that materials may be introduced into the annulus between the casing and the wall of the borehole. Perforating is accomplished by lowering into the well a perforating gun, or perforator, that fires electrically detonated bullets or shaped charges from the surface.

Permeability: A measure of the ease with which fluids can flow through a porous rock.

pH: A measure of the acidity or alkalinity of a solution, numerically equal to 7 for neutral solutions, increasing with increasing alkalinity and decreasing with increasing acidity.

Primary recovery: Oil production in which only existing natural energy sources in the reservoir provide for movement of the well fluids to the wellbore.

Produced water: The water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil and gas. It can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

Producing zone: The zone or formation from which oil or gas is produced.

Production: The phase of the petroleum industry that deals with bringing the well fluids to the surface and separating them. Production also includes storing, gauging, and otherwise preparing the product for the pipeline.

Production casing: The last string of casing or liner that is set in a well, inside of which is usually suspended the tubing string.

RCRA (Resource Conservation and Recovery Act): The Federal statute enacted in 1976 (and subsequent amendments) which amended the Solid Waste Disposal Act. Among other things, RCRA and its amendments established and/or augmented three significant programs: the hazardous waste management program, the solid waste program, and the underground storage tank program.

Reference concentration (RfC): An estimate (with uncertainty spanning perhaps an order of magnitude) of a daily inhalation exposure of the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime.

Reservoir: A subsurface, porous, permeable rock body in which oil or gas or both are stored. Most reservoir rocks are limestones, dolomites, sandstones, or a combination of these. The three basic types of hydrocarbon reservoirs are oil, gas, and condensate. An oil reservoir generally contains three fluids--gas, oil, and water--with oil the dominant product. In the typical oil reservoir, these fluids occur in different phases because of the variance in their gravities. Gas, the lightest, occupies the upper part of the reservoir rocks; water occupies, the lower part; and oil occupies, the intermediate section. In addition to occurring as a cap or in solution, gas may accumulate independently of the oil; if so, the reservoir is called a gas reservoir. Associated with the gas, in most instances, are salt water and some oil. In a condensate reservoir, the hydrocarbons may exist as a gas, but when brought to the surface, some of the heavier ones condense to a liquid or condensate. At the surface the hydrocarbons from a condensate reservoir consist of gas and a high gravity crude (i.e., the condensate). Condensate wells are sometimes called gas-condensate reservoirs).

Rig: The derrick, drawworks, and attendant surface equipment of a drilling or workover unit.

Routine emissions: The anticipated emissions of a regulated substance or other extremely hazardous substance into the air from a stationary source during its normal operation.

Secondary recovery: Any method by which an essentially depleted reservoir is restored to producing status by the injection of liquids or gases (from extraneous sources) into the wellbore. This injection effects a restoration of reservoir energy, which moves the formerly unrecoverable secondary reserves through the reservoir to the wellbore.

Shale shaker: A series of trays with sieves that vibrate to remove cuttings from the circulating fluid in rotary drilling operations. The size of the openings in the sieve is carefully selected to match the size of the solids in the drilling fluid and the anticipated size of cuttings. It is also called a shaker.

Short-term exposure limit (STEL): A time-weighted average that the American Conference of Government and Industrial Hygienists (ACGIH) indicates should not be exceeded any time during the work day. Exposures at the STEL should not be longer than 15 minutes and should not be repeated more than 4 times per day. There should be at least 60 minutes between successive exposure at the STEL.

Shut-in well: A non-producing well with its pump turned off, and the stuffing box closed, which has been inspected to ensure there is no leakage.

Sour: Containing hydrogen sulfide or caused by hydrogen sulfide or another sulfur compound.

Stripper well: A well nearing depletion that produces a very small amount of oil or gas.

Tail gas: gas that leaves a sulfur recovery process after most of the H_2S has been converted to SO_2.

Tank battery: A group of production tanks located in the field, used for storage of crude oil.

Tertiary recovery: A recovery method used to remove additional hydrocarbons after secondary recovery methods have been applied to a reservoir. Sometimes more hydrocarbons can be removed by injecting liquids or gases (usually different from those used in secondary recovery and applied with different techniques) into the reservoir.

Threshold limit value (TLV): The concentration of a substance below which no adverse health effects are expected to occur for workers, assuming exposure for 8 hours per day, 40 hours per week. TLVs are published by the American Conference of Governmental Hygienists (ACGIH). This listing may be useful in identifying substances used in the workplace and having the potential to be emitted into the ambient air.

Time-weighted average (TWA): An approach to calculating the average exposure over a specified time period.

Tubing: Small-diameter pipe that is run into a well to serve as a conduit for the passage of oil and gas to the surface.

Uncertainty factor (UF): One of several, generally 10-fold factors, applied to a NOAEL or a LOAEL to derive a reference dose (RfD) from experimental data. UFs are intended to account for (a) the variation in the sensitivity among the members of the human population; (b) the uncertainty in extrapolating animal data to humans; (c) the uncertainty in extrapolating from data obtained in a less-than-lifetime exposure study to chronic exposure; and (d) the uncertainty in using a LOAEL rather than a NOAEL for estimating the threshold region.

Volatile: Readily vaporized.

Waterflood: A method of secondary recovery in which water is injected into a reservoir to remove additional quantities of oil that have been left behind after primary recovery. Usually, a waterflood involves the injection of water through wells specially set up for water injection and the removal of the water and oil from the wells drilled adjacent to the injection wells.

Wellbore: A borehole; the hole drilled by the bit. A wellbore may have casing in it or may be open (i.e., uncased); or a portion of it may be cased and a portion of it may be open.

Well completion: The activities and methods necessary to prepare a well for the production of oil and gas; the method by which a flow line for hydrocarbons is established between the reservoir and the surface. The method of well completion used by the operator depends on the individual characteristics of the producing formation or formations. These techniques include open-hole completions, conventional perforated completions, sand-exclusion completions, tubingless completions, multiple completions, and miniaturized completions.

Wellhead: The equipment used to maintain surface control of a well, including the casinghead, tubing head, and Christmas tree.

Workover: One of more of a variety of remedial operations performed on a producing oil well to try to increase production. Some examples of workover operations are deepening, plugging back, pulling and resetting the liner, and squeeze-cementing.

Workover fluids: A special drilling mud used to keep a well under control when it is being worked over. A workover fluid is compounded carefully so it will not cause formation damage.

APPENDIX A

BACKGROUND INFORMATION ON THE OIL AND GAS PRODUCTION INDUSTRY

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APPENDIX A

BACKGROUND INFORMATION ON THE OIL AND GAS PRODUCTION INDUSTRY

EXPLORATION AND DEVELOPMENT

Although geological and geophysical studies provide information about potential accumulations of petroleum, only exploratory drilling can confirm the presence of petroleum.

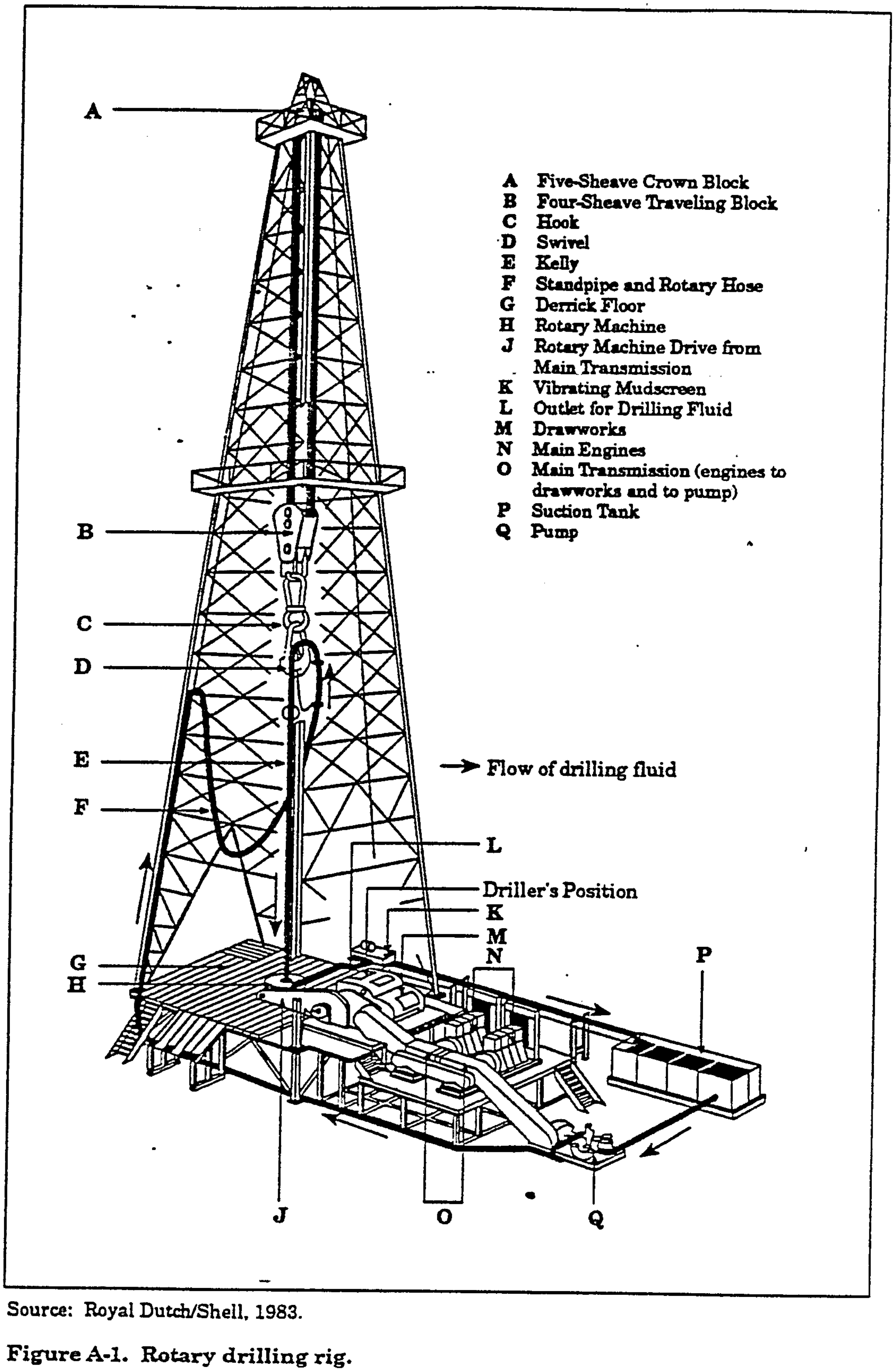
Rotary drilling, the primary drilling method in the United States, provides a safe way to control high-pressure oil/gas/water flows and allow for the simultaneous drilling of the well and removal of cuttings. This makes it possible to drill wells over 30,000 feet deep. Figure A-1 illustrates the process. Most rotary drilling operations employ a circulation system using a water- or oil-based fluid, called "mud" because of its appearance. The mud is pumped down the hollow drill pipe and across the face of the bit to provide lubrication and remove cuttings. Cuttings are removed at the surface by shale shakers, desanders, and desilters; they are then deposited in the reserve pit excavated or constructed next to the rig. Air drilling, which is considerably faster and less expensive than drilling with water- or oil-based fluids, is used in areas where high pressure or water-bearing formations are not anticipated.

Potential producing zones are normally measured and analyzed during exploratory drilling. If evidence of hydrocarbons is found, a drill stem test can show whether commercial quantities of oil and gas are present. If so, the well is prepared for production. This is called "completion." The most common method is the "cased hole" completion. Production casing is run into the hole and cemented permanently in place. Then one or more strings of production tubing are set in the hole, productive intervals are isolated with packers, and surface equipment is installed. The well is not actually completed until a gun or explosive charge perforates the production casing and begins the flow of petroleum into the well (U.S. EPA, 1987). Figure A-2 shows a cross section of a common well.

While a well is being drilled, heavy fittings have to be installed at the surface where the casing is attached, as each string of casing is inserted into the hole. Each part of the casing head is supported by a part of the casing head which was installed at the top of the next larger string of casing when it was run (U.S. EPA, 1987).

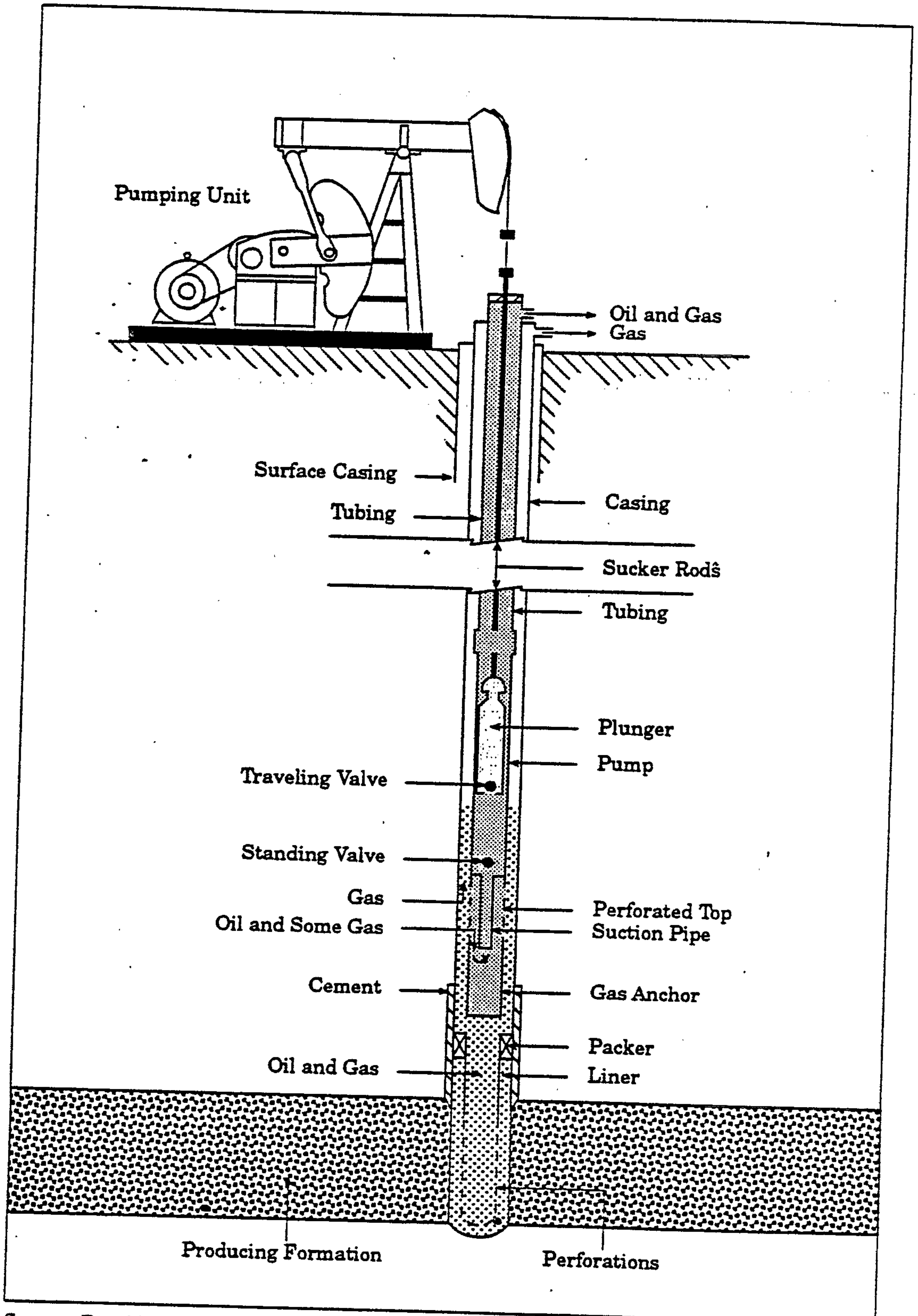
HOW OIL AND GAS ARE PRODUCED

Production operations generally include all activities associated with the recovery of oil and gas from geologic formations. They can be divided into activities associated with downhole operations and activities associated with surface operations. Downhole operations include primary secondary, and tertiary recovery methods, well workovers, and well stimulation activities. Activities associated with surface operations include oil/gas/water



Source: Royal Dutch/Shell, 1983.

Figure A-1. Rotary drilling rig.



Source: Royal Dutch/Shell, 1983.

Figure A-2. Cross section of a well pumping installation.

separation, fluid treatment, and disposal of produced water. The term "extraction" is commonly used to refer to activities associated with getting oil or gas to the surface; production includes both extraction and the surface operations involved in processing the materials extracted from the well. Production, as discussed in this report, is limited to the processing and storage that occurs at the well site. Transportation and further processing is not included in the scope of this report.

Downhole Operations

The initial production of oil or gas from the reservoir is called primary recovery. Natural pressure or artificial lift methods (surface or subsurface pumps and gas lifts) are used to bring the gas or oil out of the formation and to the surface (see Figure A-3). High-pressure gas can also be injected to lift the oil from the reservoir.

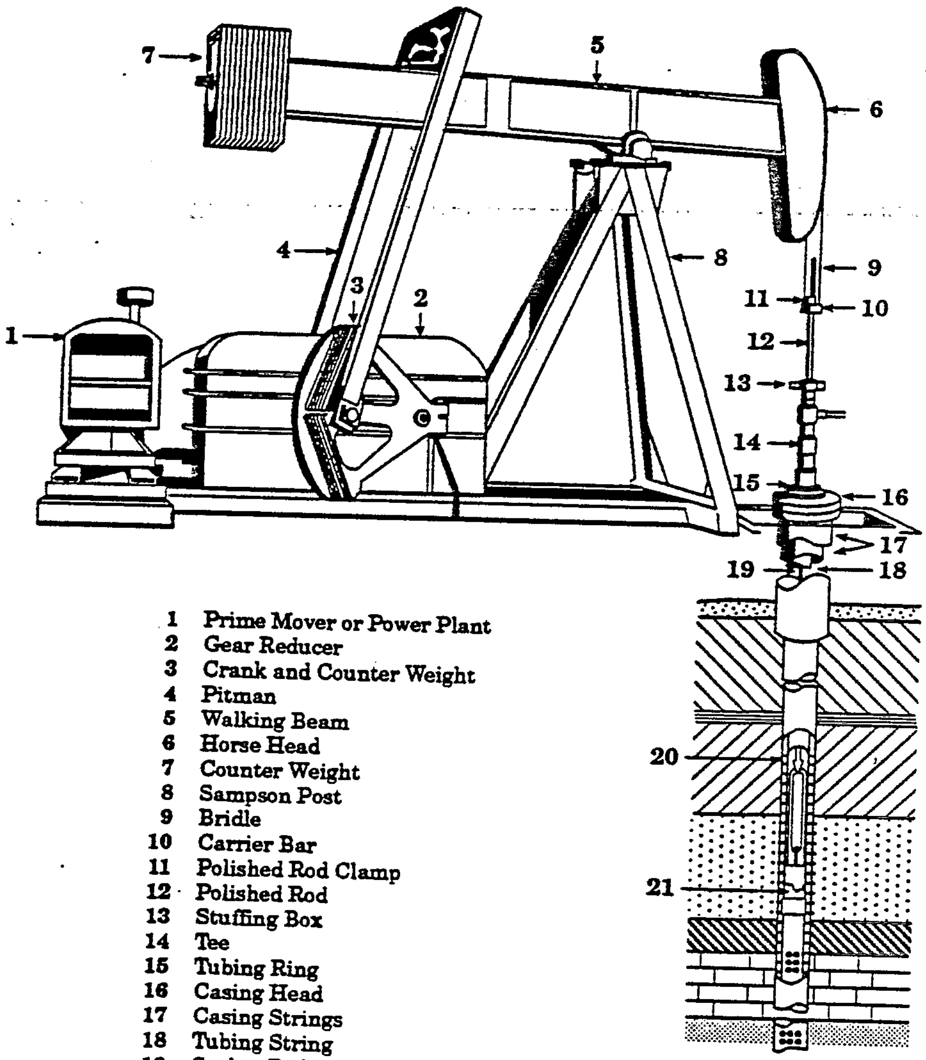
During the primary recovery stage, natural pressure in the reservoir may decline and artificial lift may be needed. One of three general types of pumps may be used: (1) pumps at the bottom of the hole run by a string of rods; (2) pumps at the bottom of the hole run by high-pressure liquids; and (3) bottom-hole centrifugal pumps (API, 1976).

The pumping unit includes a complete set of surface equipment that imparts an up-and-down motion to the sucker-rod string, which is connected the bottom-hole pump. Figure A-2 shows the parts of such as unit. Deep wells often require the long-stroke pumping provided by hydraulic units.

A stuffing box is used in a pumping well to pack or seal off the pressure inside the tubing so that liquid and gas cannot leak outside the polished rod. A stuffing box consists of flexible material or packing housed in a box which provides a method of compressing the packing. The packing material gradually wears out and must be replaced before it loses its effectiveness as a seal (API, 1976).

Primary recovery methods alone can produce oil and gas from most reservoirs, but over the life of the well production gradually decreases. Some form of secondary recovery will eventually be needed in nearly all wells. Secondary recovery methods inject gas or liquid into the reservoir to maintain pressure. The most frequent method is waterflooding, which involves injecting treated water (seawater, fresh water or produced water) into the formation through a separate well.

When secondary recovery methods are no longer adequate, the last portion of the oil that can be economically produced is recovered by tertiary methods. These include chemical, physical, and thermal methods or some combination. Chemical methods involve injection of fluids containing substances such as surfactants and polymers. Miscible oil recovery methods inject gases such as carbon dioxide and natural gas that combine with the oil. Thermal recovery methods include steam injection and *in situ* combustion (or "fire flooding"). The injected gases or fluids from secondary and tertiary recovery operations are



1 Prime Mover or Power Plant
2 Gear Reducer
3 Crank and Counter Weight
4 Pitman
5 Walking Beam
6 Horse Head
7 Counter Weight
8 Sampson Post
9 Bridle
10 Carrier Bar
11 Polished Rod Clamp
12 Polished Rod
13 Stuffing Box
14 Tee
15 Tubing Ring
16 Casing Head
17 Casing Strings
18 Tubing String
19 Sucker Rod
20 Fluid Level
21 Rod Pump

Source: API, 1976.

Figure A-3. Main parts of a pumping unit.

dissolved or mixed with the oil produced by the well and must be removed during surface production operations (U.S. EPA, 1987).

Workovers are another type of downhole production operation. Workovers are used to restore or increase production when downhole mechanical failures or blockages, such as sand or paraffin deposits have inhibited the flow of a well. Fluids circulated into the well for a workover must be compatible with the formation and must not adversely affect permeability. The workover fluid may be reclaimed or disposed of when the well is put back into production. Workover fluids are similar to completion fluids, which are special fluids used when the well is completed (ready for the production phase), to minimize formation damage and control potential problems such as H_2S corrosion.

Other chemicals are used periodically or continuously to inhibit corrosion, reduce friction, or simply keep the well flowing (U.S. EPA, 1987).

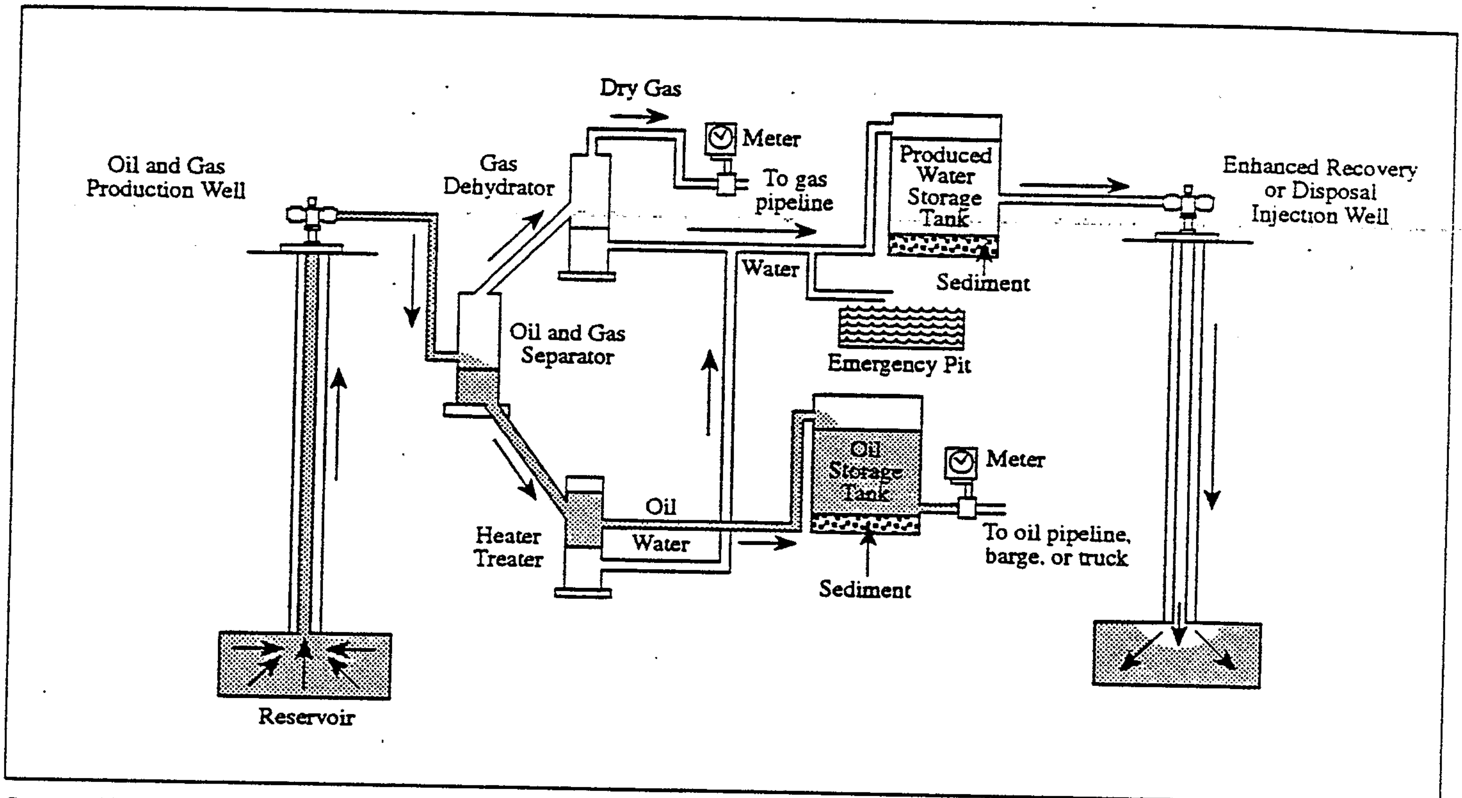
Surface Operations

As fluids are pumped to the surface, they are collected and treated to separate the various components (oil, gas, gas liquids, and water). Figure A-4 shows the separation process. These surface operations become more complex as secondary and tertiary recovery methods are employed. The ratio of water and other fluids to oil tends to increase as producing reservoirs are depleted. In new wells little or no water may be produced. The volume of water produced by stripper wells varies greatly. Stripper wells may produce more than 100 barrels of water for every barrel of oil, especially if waterflooding is used as a secondary recovery (U.S. EPA, 1987).

Separation involves the use of equipment to separate the gas, oil and water from each other. The actual separation may be accomplished in a single step or several steps depending on the relative amounts and the physical characteristics of the material which is delivered to the surface. Complete separation may require several stages involving different pressures, temperatures, and possibly additives if the material is delivered to the surface at a high pressure and the oil and gas are present in an emulsion.

After separation, the gas is transported by pipeline to a gas processing facility if the quantities from a specific well are adequate. If the quantities are inadequate, the gas is flared (burned). Gas processing facilities remove inerts (N_2, CO_2), hydrogen sulfide (H_2S), and liquids (oil and water) to produce pipeline quality gas which has a nominal heating value of 1000 BTU per cubic foot. Gas can also be re-injected into the well if necessary to help manage the reservoir or the production from the well.

Oil that is recovered from the separators at the well is placed in tanks and transported to a refinery for processing. This transportation is by pipeline if the quantities are adequate to justify installation of a pipeline or by truck if the production is small.



Source: U.S. EPA, 1987.

Figure A-4. Typical extraction operation showing separation of oil, gas, and water.

Water recovered from the separators at the well is placed in tanks or pools. This water will ultimately be reinjected into the producing formation, injected into a disposal well, or discharged. Reinjection into the producing formation and injection into a disposal well are the most common methods for water disposal; discharge is rarely used. Permits are usually required for these water disposition options.

The equipment used at the surface to control the well is called the well head. If high production or significant gas pressure is expected, the well head is usually built of cast or forged steel, and machined to a close fit. These sealed fittings prevent well fluids from blowing or leaking at the surface. Parts of the well head may be designed to hold pressures up to 20,000 lb per sq in (psi). Some well heads are just simple assemblies to support the weight of the tubing in the well, and may not be built to hold pressure. For stripper wells, or other low-production, low-pressure wells, a simple well head can be used as long as only small amounts of gas are produced with the oil (API, 1976).

High pressures or corrosive gases such as H_2S require well heads with special valves and control equipment to control the flow of oil and gas from the well. These are constructed of heavy metal and installed above the casing head or tubing head before the well is completed. This collection of valves is called a Christmas tree because of its shape and the large number of fittings branching out above the well head. The tree diverts fluids through alternative chokes (API, 1976).

Safety measures should be adequate to prevent high pressure wells from going out of control. Equipment is available that automatically shuts off production if there is damage to the wellhead or to automatic surface safety valves at the wellhead.

Simpler types of Christmas trees can be used on low pressure or pumping wells. Pressure gauges on the well head and Christmas tree measure the pressure in the casing and tubing. If the pressures under various operating conditions are known, better control can be maintained (API, 1976).

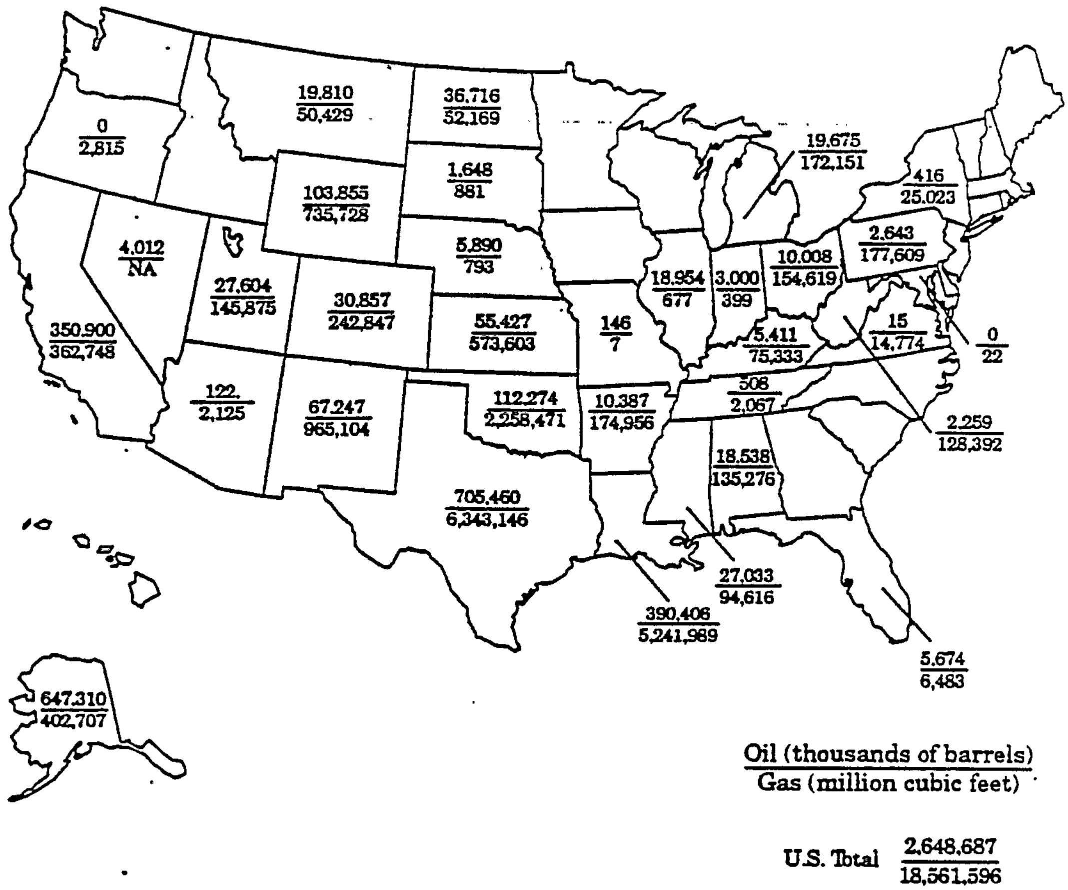
OVERVIEW OF THE INDUSTRY

The U.S. petroleum industry drilled its first oil well in 1859. Since that first well, the oil and gas industry has grown to be extremely complex and diverse. In 1990, approximately 869,887 wells in over 33 States were producing oil and gas in the United States. The oil and gas obtained from these wells is found at depths ranging from 30 feet to 30,000 feet below the earth's surface. The major U.S. areas of onshore production include the southwest (including California), the midwest, and Alaska, with lesser contributions from the Appalachians. Table A-1 lists production estimates for the oil and gas producing States. In 1990-1991, Texas led all States in oil and natural gas production, turning out 705 million barrels of oil and 6.3 trillion cubic feet of natural gas (Petroleum Independent, 1992). Figure A-5 shows U.S. oil and gas production by State. The bar graph in Figure A-6 shows distribution of States containing more than 70 percent of gas wells in the U.S. Some of these

Table A-1. 1991 Oil and 1990 Gas Production Estimates

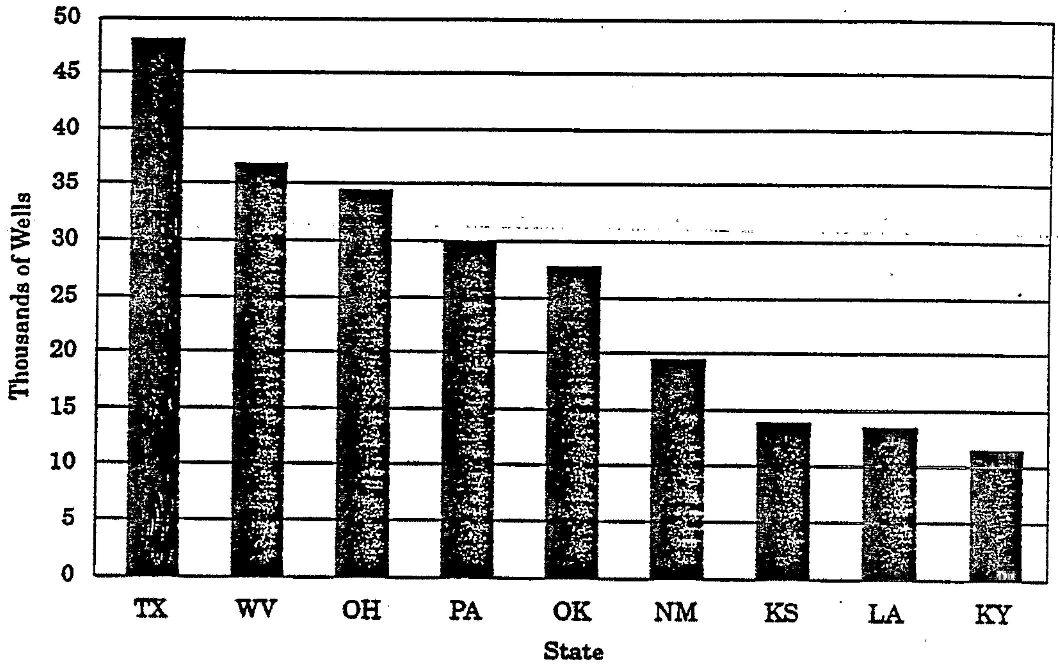
State	Number of Producing Oil Wells[a]	Oil Production (thousands of barrels)[b]	Number of Producing Gas Wells[a]	Gas Production (million cubic feet)[b]
Alabama	872	18,538	2,038	135,276
Alaska	1,466	647,310	109	402,907
Arizona	22	122	NA	2,125
Arkansas	7,265	10,387	3,460	174,956
California	43,375	350,900	1,169	362,748
Colorado	6,596	30,857	5,097	242,897
Florida	83	5,674	NA	6,483
Illinois	31,874	19,954	356	677
Indiana	7,506	3,000	1,311	399
Kansas	45,470	55,427	14,043	573,603
Kentucky	22,741	5,411	11,713	75,333
Louisiana	23,812	390,406	13,530	5,241,989
Maryland	0	0	NA	22
Michigan	4,570	19,675	1,438	172,151
Mississippi	2,168	27,033	629	94,616
Missouri	854	146	NA	7
Montana	3,854	19,810	2,428	50,429
Nebraska	1,440	5,890	NA	793
Nevada	46	4,012	NA	NA
New Mexico	18,546	67,247	19,537	965,104
New York	4,043	416	5,406	25,023
North Dakota	3,546	36,716	103	52,169
Ohio	30,089	10,008	34,697	154,619
Oklahoma	95,468	112,274	27,919	2,258,471
Oregon	0	0	NA	2,815
Pennsylvania	22,338	2,643	30,000	177,609
South Dakota	149	1,648	52	881
Tennessee	736	508	527	2,067
Texas	188,829	705,460	48,075	6,343,146
Utah	1,972	27,604	742	145,875
Virginia	25	15	819	14,774
West Virginia	15,950	2,143	37,000	178,000
Wyoming	11,397	103,855	2,431	735,728
Federal Waters	4,468	NA	3,591	NA
Other	25	NA	147	NA
U.S.	601,520	2,684,687	268,367	18,561,596

Combined Source: Petroleum Independent, September 1992, attributes the individual column sources to:
[a]World Oil.
[b]Energy Information Administration.
–NA Not available.



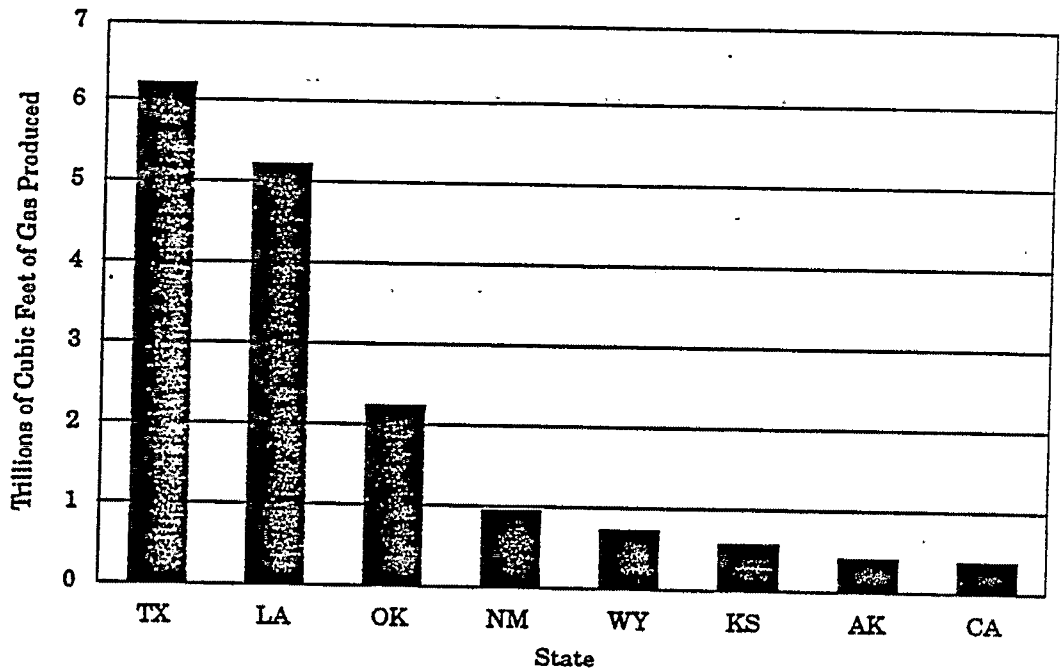
Combined Source: Petroleum Independent, September 1992, attributes the oil and gas sources to: World Oil Energy Information Administration.

Figure A-5. 1991 U.S. oil and gas production by State.



Source: World Oil (in Petroleum Independent, September 1992)

Figure A-6. States with the most producing gas wells in 1990.



Source: Energy Information Administration (in Petroleum Independent, September 1992).

Figure A-7. Gas production in 1990 from the top producing states.

States, however, are not the largest gas producers. Figure A-7 shows that Texas, Louisiana, Oklahoma, New Mexico, Wyoming, Kansas, Alaska, and California account for 92 percent of domestic gas production. Alaska, California, Louisiana, and Texas account for 78 percent of domestic oil production.

Principal Production Industry Groups

The industry can be divided into four groups. The first group consists of the major oil companies. These companies are highly vertically integrated, which means that they perform both "upstream" activities (oil exploration, development and production) and "downstream" activities (transportation, refining and marketing).

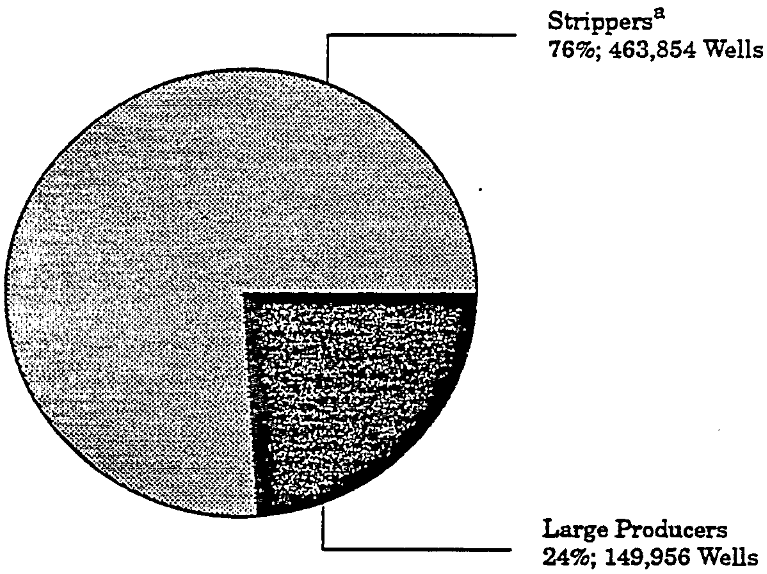
The second group is the large independents. These companies primarily explore, develop, and produce oil and gas, but do not perform downstream activities. Some large independents produce oil and gas only, while others provide such additional services as contract drilling and pipeline operations.

The third group is the small independents. Little information is available that would characterize this group quantitatively. However, small independents are known to have fewer wells and/or lower production wells. The lower operating expenses of small independents makes it more affordable to continue producing small quantities from low volume wells.

The fourth group consists of companies that provide a variety of specialized services to the oil and gas drilling rigs and platforms, such as designing, manufacturing, and installing specialized hardware. They also provide geophysical support, drilling mud, and logging services.

Diversity of Production

Production from individual wells varies greatly from a high of 11,500 barrels per day to less than 10 barrels per day. As shown in Figure A-8, over 70 percent of U.S. oil wells are "stripper" wells. The definition of a stripper well varies from State to State. However, these wells are generally defined as wells that produce 10 barrels of oil per day or less, or 100 thousand cubic feet (mcf) of gas per day or less. In 1990, 463,854 stripper wells existed and produced a total of 383,197,000 barrels of oil (NSWA, 1991). Stripper well production is shown in Table A-2. Figure A-9 shows that stripper wells produced 14 percent of the 2,684,687,000 barrels of oil produced in the United States in 1990 (U.S. EIA, 1991; U.S. EIA, 1987). Figure A-10 shows the proportion of stripper wells in the 10 States with the largest numbers of wells overall. In all 10 States, stripper wells comprised more 50 percent of producing wells. However, Figure A-11 demonstrates that in the 10 top oil producing States, oil from stripper wells is relatively low in volume. These wells typically are near depletion of recoverable natural resources and produce only a small quantity of oil or gas.



[a] Strippers are defined as those producing 10 barrels a day or less.

Source: Interstate Oil and Gas Compact Commission and National Stripper Well Association.

Figure A-8. Number of producing oil wells in the U.S. in 1990.

Table A-2. 1990 Oil Production from Stripper Wells by State

Location	Number of Producing Wells[a]	Number of Producing Stripper[c] Wells	Percentage of Producing Wells Which Are Stripper Wells*	Amount of Crude Oil Produced (thousands of barrels)[b]
Alabama	872	514	58%	18,538
Alaska	1,466	0	0%	647,310
Arizona	22	12	55%	122
Arkansas	7,265	7,290	NA*	10,387
California	43,375	26,128	60%	350,900
Colorado	6,596	5,234	79%	30,857
Florida	83	0	0%	5,674
Illinois	31,874	33,700	NA*	19,954
Indiana	7,506	5,764	77%	3,000
Kansas	45,470	45,227	99%	55,427
Kentucky	22,741	19,330	85%	5,411
Louisiana	23,812	17,695	74%	390,406
Michigan	4,570	3,967	87%	19,675
Mississippi	2,168	615	28%	27,033
Missouri	854	375	44%	146
Montana	3,854	3084	80%	19,810
Nebraska	1,440	1,269	88%	5,890
Nevada	46	0	0%	4,012
New Mexico	18,546	15,261	82%	67,247
New York	4,043	3,748	93%	416
North Dakota	3,546	1,205	34%	36,716
Ohio	30,089	29,576	98%	10,008
Oklahoma	95,468	73,345	77%	112,274
Pennsylvania	22,338	21,800	98%	2,643
South Dakota	149	26	17%	1,648
Tennessee	736	923	NA*	508
Texas	188,829	127,790	68%	705,460
Utah	1,972	1,026	52%	27,604
Virginia	25	22	88%	15
West Virginia	15,950	15,975	NA	2,143
Wyoming	11,397	2,953	26%	103,855
U.S.	601,520	463,854	77%	2,684,687

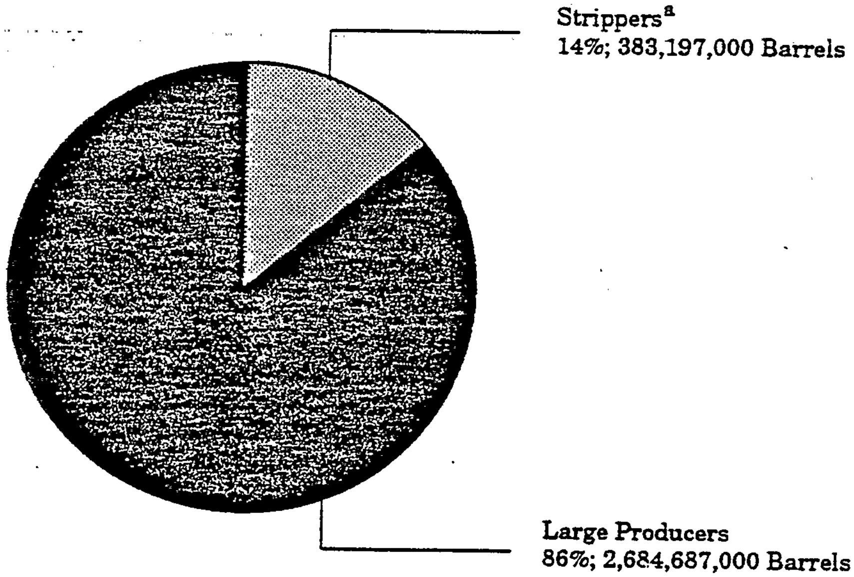
Combined Source: Petroleum Independent, September 1992, attributes the individual column sources to:
[a] World Oil.
[b] Energy Information Administration.
[c] Interstate Oil and Gas Compact Commission and National Stripper Well Association.

*Petroleum Independent warns "[number of producing stripper wells]-data cannot be compared to "Producing Oil Wells" table due to different sources and technology."

NA Unable to calculate.

Table A-2. 1990 Oil Production from Stripper Wells by State (continued)

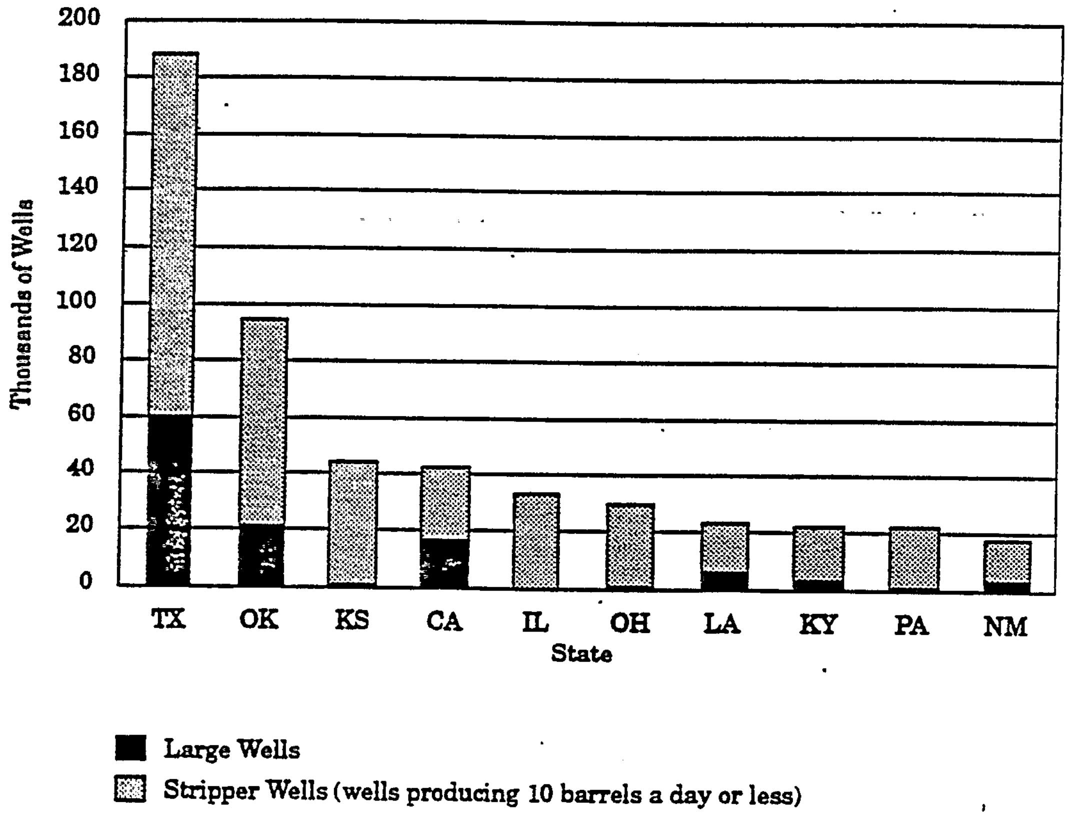
Amount of Crude Oil Produced from Stripper Wells (thousands of barrels)[c]	Percentage of Crude Oil Produced from Stripper Wells
1,486	8%
0	0%
26	21%
5,693	55%
36,405	10%
5,698	19%
0	0%
18,520	93%
3,002	NA*
40,873	74%
4,338	80%
7,154	2%
4,599	23%
802	3%
120	82%
2,449	12%
2,011	34%
0	0%
14,296	21%
383	92%
2,053	6%
7,271	73%
78,599	70%
2,622	99%
64	4%
419	83%
135,850	19%
1,035	4%
12	80%
2,122	99%
5,297	5%
389,197	14%



[a] Strippers are defined as those producing 10 barrels a day or less.

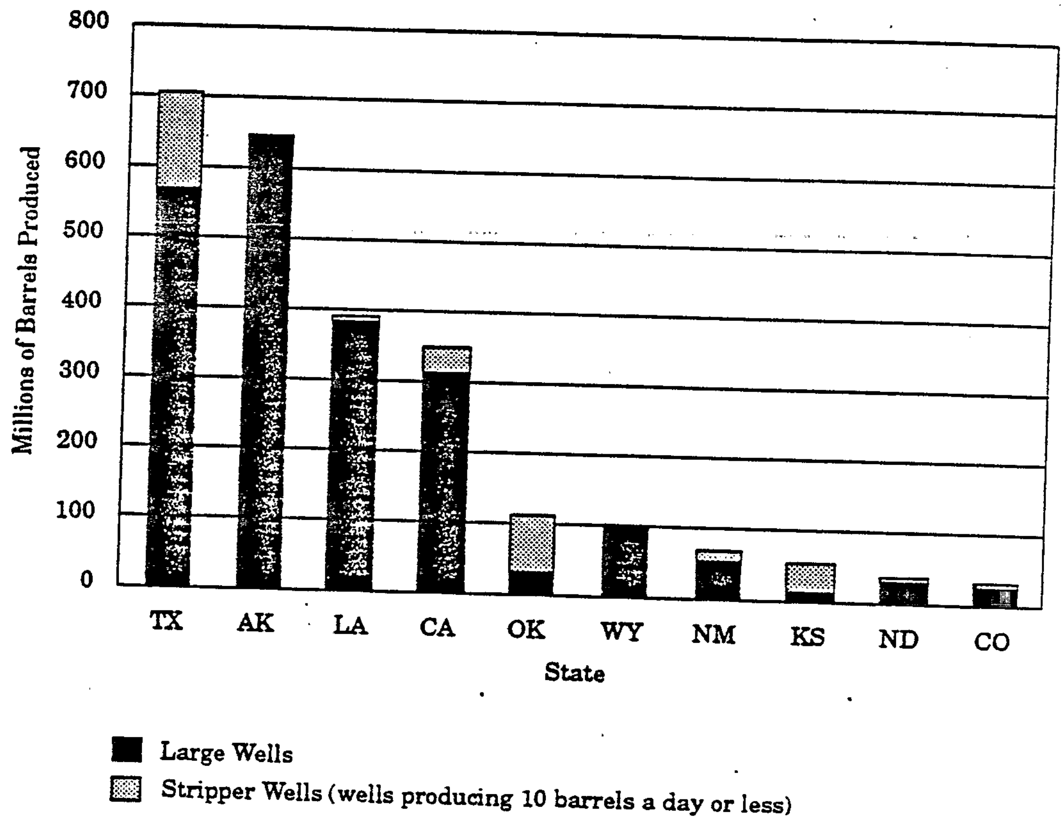
Source: Interstate Oil and Gas Compact Commission and National Stripper Well Association.

Figure A-9. 1990 U.S. oil production.



Source: World Oil (in Petroleum Independent, September 1992).

Figure A-10. States with the largest number of producing oil wells in 1990.



Source: World Oil (in Petroleum Independent, September 1992).

Figure A-11. Oil production in 1990 from the top producing states.

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World Oil Magazine, Forecast Review Issue. February 1992.

APPENDIX B

SUBJECTS OF STATE H_2S REGULATIONS AND GUIDELINES

Table B-1. Subjects of State H_2S Regulations and Guidelines

Regulations and Guidelines	Oklahoma	Texas	Michigan	California*
Characteristics and Effects of H_2S (including emergency rescue, resuscitators, effects on metal and artificial respiration)	NA	•	•	•
Initial Testing	•	NA	•	•
Periodic Gas Analyses	•	NA	NA	NA
Nuisance Odors	•	NA	NJ	NA
Guidelines for Safe Drilling Operations				
A. Location Requirements	•	•	•	•
B. Drilling Equipment (Including blowout preventer, controls, piping and accessories, etc.)	•	•	•	•
C. Monitoring Equipment (including alarm systems and gas detection equipment)	•	•	•	•
D. Personal Protective Equipment (including all personnel, breathing apparatus, equipment specs., etc.)	•	•	•	•
E. Employee Physical Requirements	NA	•	NA	NA
F. Training Requirements	•	•	•	NA
G. Drills and Orientations	•	•	•	•
H. Maintenance of Equipment	•	•	•	•
I. Warning Systems	•	•	•	•
J. Evacuation	•	•	•	•
Guidelines for Safe Production Operations				
A. Applicability	NA	•	•	NA
B. General Provisions	NA	•	•	NA
1. Concentration Determination	•	•	•	NA
2. Radius of Evacuation (ROE)	•	•	•	•
3. Escape Rate Volume Determinators	•	•	•	NA
4. Storage Tank Provisions	•	•	•	NA
5. . . . ppm ROE in excess of . . . feet	•	•	•	•
6. Implementation	•	•	•	NA
7. Control and Safety Equipment	•	•	•	•
8. Contingency Plan	•	•	•	•
9. Training	•	•	•	NA
10. Injection Provision	•	•	•	NA
11. Certificate of Compliance Provision	•	•	•	NA
12. Accident Notification	•	•	•	•

NA Not available in reviewed literature.
• The subject was identified under the State's H_2S regulations or guidelines.
A Rule 36 references API RP19.
NJ Not under Congressional jurisdiction.
MMIOSH Required by Michigan OSHA.
*CA grants the supervisor of the Oil and Gas Division discretionary authority to control H_2S releases.

APPENDIX C

ATMOSPHERIC DISPERSION CALCULATIONS FOR H_2S RELEASES FROM OIL AND GAS EXTRACTION FACILITIES

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ATMOSPHERIC DISPERSION CALCULATIONS FOR H_2S RELEASES FROM OIL AND GAS EXTRACTION FACILITIES

INTRODUCTION

The purpose of this appendix is to provide supporting details for the analyses of atmospheric dispersion of H_2S conducted for this report. In Chapter III, computer models were used, together with information on published studies of sour gas releases, to examine the range of predictions of the distances of concern for scenarios of H_2S releases from wellheads or pipelines. The inputs to the analyses are reviewed, and the outputs of three sample calculations for two of the scenarios are described. Outputs for a horizontal wellhead release are described for calculations using the SLAB and SAPLUME models. The output for a vertical wellhead release using the DEGADIS model is also described.

SUMMARY INPUT AND OUTPUT DATA

Summary data for the wellhead blowout and pipe rupture scenarios are presented in Tables C-1 and C-2, respectively. As described in Chapter III, analyses for wellhead blowouts were conducted using the SLAB, DEGADIS, and SAPLUME models. Analyses of the pipe rupture scenarios were conducted using the SACRUNCH and SAPLUME models.

The wellhead blowout scenarios in Chapter III result from various assumed flow rates as presented again in Table C-1. The following discussion presents some justification for the choice of these flow rates. Flow rates are functions of such factors as rock permeabilities, gas properties, depth, and tube and casing diameters. In practice, there are large variabilities in these parameters. One measure of the potential rate of flow from a well is the Calculated Absolute Open Flow Rate (CAOF), which is the rate of flow of gas into the well bore when the pressure is atmospheric. A sample of 15 wells in western Wyoming had CAOFs with a geometrical mean of 4.7×10^6 standard cubic feet per day (scf/d) or 1.3×10^5 cubic meters per day (m^3/d) (Layton et al., 1983). The 95 percent confidence interval spanned the range from 2.1×10^5 scf/d (5.9×10^3 m^3/d) to 10^8 scf/d (2.8×10^6 m^3/d). Alp et al. (1990) considered CAOFs of between 5×10^4 and 5×10^6 m^3/d as representative of wells in Alberta and chose 10^6 m^3/d as representative for the purposes of risk analysis. The Quest report (1992) considered CAOFs in the range 2.2×10^5 to 7.3×10^6 m^3/d for a system of wells in southwestern Wyoming. The actual flow rates out of a ruptured well will be less than the CAOF because of frictional effects in the pipework. By contrast, the Quest report and Layton et al. use the CAOF as a conservative estimate of flow rate. Based on the above discussions, a flow rate of 2×10^7 scf/d was chosen for representative calculations, with a flow rate of 10^8 scf/d being taken as an example of a very high flow rate.

TABLE C-1

SUMMARY OF INPUT AND OUTPUT DATA WELLHEAD BLOWOUT SCENARIOS

SCENARIO[a]	A	B	C	D	D(E)*
INPUTS					
Flow rate (m^3/d)	$6x10^5$	$6x10^5$	$6x10^5$	$6x10^5$	$3x10^6$
Vol. % H_2S	7.5	27	15	30	30
Density[b] @ 0°C (kg/m^3)	0.862	1.293	1.038	1.128	1.128
Release temperature (°C)	0	0	0	0	0
Total release rate (kg/s)	5.99	8.98	7.21	7.83	39.2
Release rate of H_2S (kg/s)	0.79	2.85	1.58	3.17	15.8
Ambient temperature (°C)	5	5	5	5	5
Relative humidity (%)	75	75	75	75	75
Atmospheric stability category	F	F	F	F	F
Windspeed (m/s)	1.5	1.5	1.5	1.5	1.5
Surface roughness length (m)	0.1	0.1	0.1	0.1	0.1
Effective area of release (m_2)	0.02	0.02	0.02	0.02	0.1
OUTPUTS: HORIZONTAL RELEASE					
SLAB:					
Distance to:					
LC_{01}(m)	700	2,800	1,500	2,900	7,000
ERPG-2(m)	2,800	7,000	4,700	7,000	>10,000
SAPLUME:					
Distance to:					
LC_{01} (m)	1,000	2,700	1,500	3,000	>10,000
ERPG-2(m)	3,100	10,000	5,700	10,000	>10,000
OUTPUTS: VERTICAL RELEASE					
SLAB:					
Distance to:					
LC_{01}(m)	0	0	0	0	0
ERPG-2(m)	0	0	0	0	0
DEGADIS:					
Distance to:					
LC_{01}(m)	0	0	0	0	0
ERPG-2(m)	0	0	0	0	0
SAPLUME:					
Distance to:					
LC_{01}(m)	0	0	0	0	0
ERPG-2(m)	0	0	0	0	0

[a] Scenarios from Table III-7.
[b] For comparison, density of air @ 0°C=1.293 kg/m^3.
* E=Extreme Case.

TABLE C-2

PIPE RUPTURE SCENARIOS
INPUTS AND OUTPUTS (SADENZ MODEL)

Parameters/Scenario	Composition A[a], rupture of 4" diameter pipeline[b]	Composition D[a], rupture of 16" diameter pipeline[c]
INPUTS		
Total mass released (kg)[d]	640	31,000
Total mass of H_2S (kg)	84	12,500
Duration of release (s)[d]	16	310
Density @ 0°C (kg/m^3)	0.862	1.128
Release temperature (°C)	0 (32 °F)	0 (32 °F)
Ambient temperature (°C)	5 (41 °F)	5 (41 °F)
Relative humidity (%)	75	75
Atmospheric stability category	F	F
Windspeed (m/s)	1.5	1.5
Surface roughness length(m)	0.1	0.1
OUTPUTS		
Distance to:		
LC_{01} (m)	600	4,300
ERPG-2 (m)	750	5,600

[a] Composition from Table III-5.
[b] Spacing between emergency shutdown valves is 1,000 m.
[c] Spacing between emergency shutdown valves is 3,000 m.
[d] From Figure III-22.

Table C-1 also presents values for the effective area of release. These values are derived by dividing the volumetric release rate by the velocity of release and were not the bases for the release scenarios. As stated in Chapter III, the velocity of release was assumed to be "choked," or limited, to sonic velocity (approximately 330 m/s) as a result of the high initial gas pressure.

The temperature of the gas in a well prior to expansion to atmospheric pressure through a rupture depends on the depth of the gas reservoir. The amount of cooling that results from expansion to atmospheric pressure as a result of release depends on the initial pressure and the composition. Alp et al. (1990) assume a representative release temperature of 15°C (288 K) at atmospheric pressure. In the Quest report, the authors assume a reservoir temperature of 60°C and calculate expansion temperatures of between -9°C and 3°C. The calculated results of wellhead blowout and pipeline rupture scenarios in this study are based on a representative release temperature of 0°C. This temperature is below the assumed ambient temperature of 5°C.

Atmospheric conditions characterized by low turbulence and low wind speed provide for decreased dilution of a released chemical with the surrounding air. Thus, these conditions are directionally conservative in terms of potential exposure to accidental releases. Atmospheric thermal stability, impacted by the difference between surface and air temperatures, is often described by Pasquill atmospheric stability categories. These categories range from high turbulence (A) through low turbulence (F). The "F" category is typical of still, nighttime conditions (AIChE, 1989). This category was chosen for the calculations conducted to conservatively evaluate the wellhead blowout and pipeline rupture scenarios. Wind speeds of less than 2 m/s are considered low and create little turbulence. The calculations used in this study's analyses assume a wind speed of 1.5 m/s to conservatively simulate nonturbulent conditions. Actual conditions of A - D stability and higher wind speeds will cause more rapid dilution of an accidental release and will result in a decreased affected distance. The assumption that conditions of low wind speed and stable atmospheric conditions exist uniformly for extended distances also provides conservatism to the analyses.

Terrain is another factor that may influence atmospheric dispersion of a release. The surface roughness length is a measure of the "roughness" of the terrain. Roughness is a function of the type of terrain and the presence of such features as trees and buildings. The models in this study assume that the study of the behavior of dense gas flow around obstacles and through rough terrain is controversial and is an area where further research is needed. Rough terrain will cause more turbulence to atmospheric flows above it than smooth terrain. The value of surface roughness length, 0.1 m, used in the calculated dispersion predictions, is considered to be an intermediate roughness length and typical of highly vegetated rural terrain. It should be noted that lower, more conservative values would be more appropriate in flat, barren terrain.

SAMPLE SLAB CALCULATIONS

SLAB Input

The following illustrates how the input is prepared for SLAB, using composition D from Table III-5 as an example. The SLAB input is displayed on Table C-3. The SLAB users' manual provides further guidance (Ermak, 1989).

Line 1: IDSPL is the spill source type. For an evaporating pool, IDSPL =1. For a horizontal jet release IDSPL=2. For a vertical jet release IDSPL=3. For a puff, IDSPL = 4. For the present example, the release is assumed to be horizontal, IDSPL=2.

Line 2: NCALC is a numerical substep parameter. The code developer recommends using NCALC=1. However, NCALC can be increased if numerical stability problems are encountered.

Line 3: WMS is the molecular weight of the wellhead gas in kg/gmole. From Table III-6, it is 0.0252 kg/gmol (from 25.2 g/gmol). Note, however, that the value given in Table C-3 is 0.0289 kg/gmol, for the following reason. Initially, the dilution of the plume is dominated by entrainment caused by its high momentum (its initial velocity equals that of sound). There is considerable dilution in this early phase and, by the time it is over, the density of the plume is only slightly less than that of the surrounding atmosphere. Work on marginally buoyant plumes shows that they are not likely to lift off the ground (Briggs, 1973). However, SLAB runs with WMS = 0.0252 kg/gmol show predicted plume rise that continues to a height of over 100 m. This is regarded as physically unrealistic and the computer model is "fooled" into ignoring plume rise by setting WMS equal to the effective molecular weight of air which is 28.9 g/gmol (0.0 289 kg/gmol). As noted above, this is thought to be physically realistic. The results predicted in this way will be conservative if plume rise does in fact take place.

Line 4: CPS is the vapor heat capacity at constant pressure. Similar to the above molecular weight calculation, the gas mixture vapor heat capacity is calculated by summing the product of the constituents' mole percent and vapor heat capacity. For composition D it is approximately 1,500 J/kg/K.

Line 5: TBP is the boiling point of the released material. For a pure vapor release, SLAB does not in fact use this quantity, which has been arbitrarily set equal to the boiling point of methane, 111.5K.

Line 6: CMEDO is the liquid mass fraction in the initial release and is set to zero because the release is pure vapor.

Lines 7, 8: DHE=509,880 (J/kg) and CPSL=3,349 (J/kg/K) are the heat of vaporization and the liquid specific heat for methane. Their values are taken from Table 2 of the SLAB

Users' Guide. When the released material is pure vapor, as it is in the present case, and the temperature of the cloud does not drop below the boiling point, these values are adequate because the liquid properties will not be used in the SLAB calculation. However, a value for all SLAB input properties must be specified whether they are used or not.

Line 9: RHOSL is the liquid density of the released material. This is another quantity that is not used in the calculations. It has been set equal to the density of water (1,000 kg/m^3).

Lines 10,11: SPB and SPC are parameters that go into the saturated vapor pressure formula:

$$P_s = P_a*\exp[SPA - SPB/(T + SPC)],$$

where P_s is the saturated vapor pressure, P_a is the ambient pressure (1.01×10^5 N/m^2), SPA is defined in the code and T is the local cloud temperature. Table 2 of the SLAB Users' Guide contains some values of SPB and SPC, but not for the mixture modeled here. When these values are unknown, the Users' Guide recommends default values of SPB = -1 and SPC = 0. The code then uses the Clapeyron equation to define the value of SPB. When the released material is pure vapor, as it is in the present case, and the temperature of the cloud does not drop below the boiling point, this default is adequate because the saturation pressure will not be used in the SLAB calculation. However, a value for all SLAB input properties must be specified whether they are used or not.

Lines 12-17: These lines specify the spill parameters. TS is the temperature of the released material, taken to be 273K. QS is the rate of release, estimated at 20 million scfd (7.69 kg/s). AS is the effective area of the release, 1.93×10^{-2} m^2, obtained by dividing the volumetric flow rate by the speed of sound (340 m/s). TSD is the duration of the release, 3,600.s, the assumed duration of release for a wellhead blowout. QTIS is zero except when modeling an instantaneous puff release. Finally, HS is the height of the release, arbitrarily taken to be 5 m (close to the ground).

Line 18: TAV is the concentration averaging time. This is set equal to 3,600 to be consistent with the exposure time of concern.

Line 19: XFFM is the maximum downwind extent of the calculation. A value of 10 km is used in order to obtain cloud concentration results at large distances away from the release. It is set to 2×10^4 m, which should be enough to ensure that any results of interest lie within this distance.

Lines 20-23: ZP(I) allows the user to specify up to four heights at which the concentration is calculated as a function of downwind distance. ZP(1) is set to 1.6 m (approximate head elevation above grade). The remaining ZP(I)s are zero, which means that SLAB only considers the first height.

Lines 24-29: These lines specify the meteorological conditions. ZO is the surface roughness length, which is set to 0.1 m, depicting a relatively smooth surface. ZA is the height at which the windspeed is measured (10 m). UA is the windspeed at height ZA (1.5 m/s). TA is the ambient temperature (273K). RH is the relative humidity (75%, chosen as being typical of Category F weather conditions). Finally, STAB is the stability class (F=stable). The weather conditions (Category F with a low windspeed of 1.5 m/s) have been chosen to simulate unfavorable (close to worst case) conditions.

Line 30: TER is the end of file designator. TER < 0 terminates the run.

SLAB Output

A partial SLAB output corresponding to the inputs of Table C-3 is given in Table C-4. The interpretation is as follows. The first column gives the downwind distance, x. The second column gives the time at which the maximum concentration arrives at x and the third gives the duration of cloud passage. As can be seen, the duration of passage remains equal to the duration of release until the cloud has traveled several kilometers downwind. The fourth column gives the approximate half-width of the plume, bbc. The remaining six columns give the average concentration (volume fraction) at a height of 1.6 m (as chosen in the SLAB input) for six off-axis distances that are multiples of bbc, 0.5, 1.0, 1.5, etc. The predicted concentrations are zero close in because the plume was arbitrarily released at a height of 5 m. As the plume broadens, the concentrations at height 5 m rise above zero to a maximum at about 25 m to 30 m downwind and then begin to decline as the plume dilutes further.

The effective ERPG-2 is 100 ppm and the effective LC_{01} is about 4.7×10^5 ppb. These number values are derived as follows: the ERPG-2 for pure H_2S for an exposure time of 1 hour is 3×10^4 ppb. The volume concentration of H_2S in composition D is 30 percent (see Table III-5). Therefore, the overall concentration of the total released material when the H_2S in it is at 3×10^4 ppb is $30/0.3 = 1 \times 10^5$ ppb. Similarly, the LC_{01} for pure H_2S is 1.4×10^5 ppb for an exposure time of 1 hour (see Chapter III). Therefore, the effective LC_{01} for the plume is $140/0.3 = 4.7 \times 10^5$ ppb. As explained in Chapter III, the ERPG-2 is regarded as a threshold at which emergency response might be necessary and the LC_{01} is an approximate threshold for the occurrence of fatalities among the affected population. Reading down the column headed "y/bbc=0," the concentrations first fall below 4.7×10^5 ppb (= a volume fraction of 4.7×10^{-4}) at a distance of about 3 km and below 1×10^5 ppb (= a volume fraction of 1.0×10^{-4}) at a distance of about 7 km.

SAMPLE DEGADIS CALCULATIONS

DEGADIS Input

Table C-5 displays the DEGADIS input for the same case as was prepared for SLAB in Table C-3 except that DEGADIS can only simulate a vertical jet release. The chosen values for most of the parameters have already been explained in the section on SLAB.

Lines 1-4 allow the user to input up to four lines of title.

Line 5 requires the windspeed (1.5 m/s) and the height at which the windspeed is measured (10 m).

Line 6 gives the surface roughness length (0.1 m).

Line 7 requires the parameter INDVEL, the atmospheric stability category (F=6) and the Monin-Obukhov length RML. For INDVEL=1 (the present case) the model calculates RML from the stability category and the surface roughness length, so the user does not need to specify a value for RML.

Line 8 requires the ambient temperature (273K), the ambient pressure (1 atmosphere) and the relative humidity (75%).

Line 9 gives the surface temperature, which is here set equal to the ambient temperature (273K).

Line 10 is a name for the released gas, in this case CPD for ComPosition D.

Line 11 is the molecular weight, 25.2.

Line 12 is the averaging time, taken to be equal to the duration of release, 3,600 s. It is used to calculate the increase in the effective width of the plume as a function of exposure time.

Line 13 is the temperature of the released gas, 273K.

Line 14 contains the upper level of concern (470 ppm, expressed as a volume fraction), the lower level of concern (100 ppm) and the height at which the concentrations are calculated (1.6 m).

Line 15 contains first a variable INDHT=0, meaning that heat transfer from the ground is not included, which does not matter here because the plume, air, and ground all have the same temperature. The second entry is the specific heat of the released gas at constant pressure (1,500 J/kg/K). The third entry, CPP=0, indicates that an approximation was made in which the specific heat does not vary with temperature.

Line 16 is a parameter "NDEN" that is used to specify the density profile of the released material. For NDEN=0, the release is assumed to be an ideal gas with specific heat at constant pressure 1500J/kg/K. Water condensation effects are taken into account.

Line 17 is the mass rate of release, 7.69 kg/s.

Table C-3. SLAB Input - Horizonal Wellhead Release

Value	Parameter	Line No.
2 (horizontal), 3 (vertical)	IDSPL	1
1	NCALC	2
0.0289	WMS	3
1500.	CPS	4
111.50	TBP	5
0.0	CMEDO	6
509,880.	DHE	7
3,349.	CPSL	8
1,000.	RHOSL	9
-1.0	SPB	10
0.0	SPC	11
273.	TS	12
7.69	QS	13
1.93×10^{-2}	AS	14
3,600.	TSD	15
0.	QTIS	16
5.	HS	17
3,600.	TAV	18
20,000.	XFFM	19
1.6	ZP(1)	20
0.	ZP(2)	21
0.	ZP(3)	22
0.	ZP(4)	23
0.1	ZO	24
10.	ZA	25
1.5	UA	26
273.	TA	27
75.	RH	28
F	STAB	29
-1.	TER	30

Table C-4. Partial SLAB Output

Time Averaged (TAV = 3,600 s) Volume Concentration: Concentration in the z = 1.60 Plane.

Downwind Distance x (m)	Time of Max Conc (s)	Cloud Duration (s)	Effective Half Width bbc (m)	Average Concentration (Volume Fraction) at (x,y,z), y/bbc =					
				0.0	0.5	1.0	1.5	2.0	2.5
1.00	1.80×10^{3}	3.60×10^{3}	6.95×10^{-2}	0.00	0.00	0.00	0.00	0.00	0.00
1.02	1.80×10^{3}	3.60×10^{3}	7.73×10^{-2}	0.00	0.00	0.00	0.00	0.00	0.00
1.05	1.80×10^{3}	3.60×10^{3}	8.71×10^{-2}	0.00	0.00	0.00	0.00	0.00	0.00
1.08	1.80×10^{3}	3.60×10^{3}	9.92×10^{-2}	0.00	0.00	0.00	0.00	0.00	0.00
1.13	1.80×10^{3}	3.60×10^{3}	1.14×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.18	1.80×10^{3}	3.60×10^{3}	1.32×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.24	1.80×10^{3}	3.60×10^{3}	1.54×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.32	1.80×10^{3}	3.60×10^{3}	1.81×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.41	1.80×10^{3}	3.60×10^{3}	2.14×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.52	1.80×10^{3}	3.60×10^{3}	2.54×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.66	1.80×10^{3}	3.60×10^{3}	3.03×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
1.84	1.80×10^{3}	3.60×10^{3}	3.63×10^{-1}	0.00	0.00	0.00	0.00	0.00	0.00
2.05	1.80×10^{3}	3.60×10^{3}	4.36×10^{-1}	8.35×10^{-41}	5.76×10^{-41}	1.88×10^{-41}	2.84×10^{-42}	1.93×10^{-43}	5.61×10^{-45}
2.31	1.80×10^{3}	3.60×10^{3}	5.24×10^{-1}	1.18×10^{-28}	8.13×10^{-29}	2.65×10^{-29}	4.02×10^{-30}	2.79×10^{-31}	8.76×10^{-33}
2.63	1.80×10^{3}	3.60×10^{3}	6.31×10^{-1}	3.14×10^{-20}	2.16×10^{-20}	7.03×10^{-21}	1.07×10^{-21}	7.54×10^{-23}	2.42×10^{-24}
3.01	1.80×10^{3}	3.60×10^{3}	7.61×10^{-1}	1.99×10^{-14}	1.37×10^{-14}	4.45×10^{-15}	6.79×10^{-16}	4.82×10^{-17}	1.58×10^{-18}
3.49	1.80×10^{3}	3.60×10^{3}	9.17×10^{-1}	1.86×10^{-10}	1.28×10^{-10}	4.16×10^{-11}	6.36×10^{-12}	4.55×10^{-13}	1.51×10^{-14}
4.08	1.80×10^{3}	3.60×10^{3}	1.10	9.38×10^{-8}	6.45×10^{-8}	2.10×10^{-8}	3.21×10^{-9}	2.30×10^{-10}	7.71×10^{-12}
4.79	1.80×10^{3}	3.60×10^{3}	1.33	6.31×10^{-6}	4.34×10^{-6}	1.41×10^{-6}	2.16×10^{-7}	1.55×10^{-8}	5.23×10^{-10}
5.67	1.80×10^{3}	3.60×10^{3}	1.60	1.07×10^{-4}	7.33×10^{-5}	2.38×10^{-5}	3.65×10^{-6}	2.63×10^{-7}	8.89×10^{-9}
6.75	1.80×10^{3}	3.60×10^{3}	1.91	6.99×10^{-4}	4.81×10^{-4}	1.56×10^{-4}	2.39×10^{-5}	1.73×10^{-6}	5.87×10^{-8}
8.07	1.80×10^{3}	3.60×10^{3}	2.28	2.41×10^{-3}	1.66×10^{-3}	5.37×10^{-4}	8.24×10^{-5}	5.95×10^{-6}	2.03×10^{-7}
9.68	1.80×10^{3}	3.60×10^{3}	2.72	5.35×10^{-3}	3.68×10^{1}	1.19×10^{-3}	1.83×10^{-4}	1.32×10^{-5}	4.51×10^{-7}
1.17×10^{1}	1.80×10^{3}	3.60×10^{3}	3.22	8.87×10^{-3}	6.09×10^{-3}	1.98×10^{-3}	3.03×10^{-4}	2.19×10^{-5}	7.48×10^{-7}
1.41×10^{1}	1.81×10^{3}	3.60×10^{3}	3.79	1.22×10^{-2}	8.38×10^{-3}	2.72×10^{-3}	4.17×10^{-4}	3.02×10^{-5}	1.03×10^{-6}
1.71×10^{1}	1.81×10^{3}	3.60×10^{3}	4.43	1.49×10^{-2}	1.03×10^{-2}	3.33×10^{-3}	5.11×10^{-4}	3.70×10^{-5}	1.27×10^{-6}
2.07×10^{1}	1.81×10^{3}	3.60×10^{3}	5.11	1.69×10^{-2}	1.16×10^{-2}	3.78×10^{-3}	5.80×10^{-4}	4.20×10^{-5}	1.43×10^{-6}
2.52×10^{1}	1.81×10^{3}	3.60×10^{3}	5.79	1.82×10^{-2}	1.25×10^{-2}	4.05×10^{-3}	6.22×10^{-4}	4.50×10^{-5}	1.54×10^{-6}
3.07×10^{1}	1.81×10^{3}	3.60×10^{3}	6.55	1.84×10^{-2}	1.27×10^{-2}	4.11×10^{-3}	6.31×10^{-4}	4.57×10^{-5}	1.57×10^{-6}

(continued)

Table C-4 (cont)

Time Averaged (TAV = 3,600 s) Volume Concentration: Concentration in the z = 1.60 Plane.

Downwind Distance x (m)	Time of Max Conc (s)	Cloud Duration (s)	Effective Half Width bbc (m)	Average Concentration (Volume Fraction) at (x,y,z), y/bbc = 0.0	0.5	1.0	1.5	2.0	2.5
3.74×10^{1}	1.82×10^{3}	3.60×10^{3}	7.42	1.80×10^{-2}	1.23×10^{-2}	4.01×10^{-3}	6.15×10^{-4}	4.45×10^{-5}	1.52×10^{-6}
4.56×10^{1}	1.82×10^{3}	3.60×10^{3}	8.39	1.70×10^{-2}	1.17×10^{-2}	3.78×10^{-3}	5.80×10^{-4}	4.20×10^{-5}	1.43×10^{-6}
5.57×10^{1}	1.83×10^{3}	3.60×10^{3}	9.47	1.56×10^{-2}	1.08×10^{-2}	3.49×10^{-3}	5.35×10^{-4}	3.88×10^{-5}	1.33×10^{-6}
6.81×10^{1}	1.83×10^{3}	3.60×10^{3}	1.07×10^{1}	1.42×10^{-2}	9.77×10^{-3}	3.17×10^{-3}	4.86×10^{-4}	3.52×10^{-5}	1.20×10^{-6}
8.32×10^{1}	1.84×10^{3}	3.60×10^{3}	1.20×10^{1}	1.28×10^{-2}	8.77×10^{-3}	2.85×10^{-3}	4.37×10^{-4}	3.16×10^{-5}	1.08×10^{-6}
1.02×10^{2}	1.85×10^{3}	3.60×10^{3}	1.34×10^{1}	1.14×10^{-2}	7.81×10^{-3}	2.53×10^{-3}	3.89×10^{-4}	2.82×10^{-5}	9.63×10^{-7}
1.25×10^{2}	1.86×10^{3}	3.60×10^{3}	1.51×10^{1}	1.00×10^{-2}	6.90×10^{-3}	2.24×10^{-3}	3.43×10^{-4}	2.49×10^{-5}	8.50×10^{-7}
1.52×10^{2}	1.87×10^{3}	3.60×10^{3}	1.70×10^{1}	8.80×10^{-3}	6.05×10^{-3}	1.96×10^{-3}	3.01×10^{-4}	2.18×10^{-5}	7.44×10^{-7}
1.87×10^{2}	1.89×10^{3}	3.60×10^{3}	1.92×10^{1}	7.68×10^{-3}	5.28×10^{-3}	1.71×10^{-3}	2.63×10^{-4}	1.90×10^{-5}	6.51×10^{-7}
2.29×10^{2}	1.90×10^{3}	3.60×10^{3}	2.18×10^{1}	6.65×10^{-3}	4.57×10^{-3}	1.48×10^{-3}	2.27×10^{-4}	1.65×10^{-5}	5.61×10^{-7}
2.80×10^{2}	1.93×10^{3}	3.60×10^{3}	2.49×10^{1}	5.71×10^{-3}	3.92×10^{-3}	1.27×10^{-3}	1.95×10^{-4}	1.41×10^{-5}	4.84×10^{-7}
3.43×10^{2}	1.96×10^{3}	3.60×10^{3}	2.87×10^{1}	4.85×10^{-3}	3.33×10^{-3}	1.08×10^{-3}	1.66×10^{-4}	1.20×10^{-5}	4.10×10^{-7}
4.20×10^{2}	1.99×10^{3}	3.60×10^{3}	3.33×10^{1}	4.07×10^{-3}	2.80×10^{-3}	9.09×10^{-4}	1.39×10^{-4}	1.01×10^{-5}	3.44×10^{-7}
5.15×10^{2}	2.04×10^{3}	3.60×10^{3}	3.91×10^{1}	3.38×10^{-3}	2.32×10^{-3}	7.55×10^{-4}	1.16×10^{-4}	8.38×10^{-6}	2.89×10^{-7}
6.30×10^{2}	2.09×10^{3}	3.60×10^{3}	4.65×10^{1}	2.77×10^{-3}	1.91×10^{-3}	6.19×10^{-4}	9.49×10^{-5}	6.87×10^{-6}	2.36×10^{-7}
7.73×10^{2}	2.15×10^{3}	3.60×10^{3}	5.58×10^{1}	2.25×10^{-3}	1.54×10^{-3}	5.01×10^{-4}	7.68×10^{-5}	5.57×10^{-6}	1.90×10^{-7}
9.47×10^{2}	2.23×10^{3}	3.60×10^{3}	6.75×10^{1}	1.80×10^{-3}	1.24×10^{-3}	4.02×10^{-4}	6.16×10^{-5}	4.46×10^{-6}	1.49×10^{-7}
1.16×10^{3}	2.33×10^{3}	3.60×10^{3}	8.23×10^{1}	1.43×10^{-3}	9.82×10^{-4}	3.19×10^{-4}	4.89×10^{-5}	3.54×10^{-6}	1.22×10^{-7}
1.42×10^{3}	2.45×10^{3}	3.60×10^{3}	1.01×10^{2}	1.12×10^{-3}	7.73×10^{-4}	2.51×10^{-4}	3.85×10^{-5}	2.79×10^{-6}	9.64×10^{-8}
1.74×10^{3}	2.60×10^{3}	3.60×10^{3}	1.24×10^{2}	8.81×10^{-4}	6.05×10^{-4}	1.96×10^{-4}	3.01×10^{-5}	2.18×10^{-6}	7.55×10^{-8}
2.13×10^{3}	2.78×10^{3}	3.60×10^{3}	1.52×10^{2}	6.86×10^{-4}	4.71×10^{-4}	1.53×10^{-4}	2.35×10^{-5}	1.70×10^{-6}	5.91×10^{-8}
2.62×10^{3}	3.00×10^{3}	3.60×10^{3}	1.86×10^{2}	5.31×10^{-4}	3.65×10^{-4}	1.19×10^{-4}	1.82×10^{-5}	1.32×10^{-6}	4.37×10^{-8}
3.21×10^{3}	3.27×10^{3}	3.60×10^{3}	2.28×10^{2}	4.08×10^{-4}	2.81×10^{-4}	9.11×10^{-5}	1.40×10^{-5}	1.01×10^{-6}	3.52×10^{-8}
3.93×10^{3}	3.60×10^{3}	3.60×10^{3}	2.77×10^{2}	3.09×10^{-4}	2.13×10^{-4}	6.90×10^{-5}	1.06×10^{-5}	7.65×10^{-7}	2.70×10^{-8}
4.82×10^{3}	4.10×10^{3}	3.87×10^{3}	3.40×10^{2}	2.05×10^{-4}	1.41×10^{-4}	4.58×10^{-5}	7.02×10^{-6}	5.10×10^{-7}	1.76×10^{-8}
5.94×10^{3}	4.70×10^{3}	4.19×10^{3}	4.14×10^{2}	1.39×10^{-4}	9.57×10^{-5}	3.11×10^{-5}	4.77×10^{-6}	3.46×10^{-7}	1.09×10^{-8}
7.33×10^{3}	5.45×10^{3}	4.58×10^{3}	5.02×10^{2}	9.06×10^{-5}	6.22×10^{-5}	2.02×10^{-5}	3.10×10^{-6}	2.24×10^{-7}	8.61×10^{-9}
9.07×10^{3}	6.36×10^{3}	5.03×10^{3}	6.05×10^{2}	5.27×10^{-5}	3.62×10^{-5}	1.17×10^{-5}	1.80×10^{-6}	1.31×10^{-7}	4.02×10^{-9}
1.13×10^{4}	7.47×10^{3}	5.57×10^{3}	7.23×10^{2}	2.55×10^{-5}	1.75×10^{-5}	5.70×10^{-6}	8.73×10^{-7}	6.35×10^{-8}	2.33×10^{-9}
1.40×10^{4}	8.84×10^{3}	6.11×10^{3}	8.62×10^{2}	1.46×10^{-5}	1.00×10^{-5}	3.26×10^{-6}	5.00×10^{-7}	3.61×10^{-8}	1.59×10^{-9}
1.75×10^{4}	1.05×10^{4}	6.67×10^{3}	1.02×10^{3}	1.04×10^{-5}	7.13×10^{-6}	2.31×10^{-6}	3.55×10^{-7}	2.58×10^{-8}	6.70×10^{-10}
2.20×10^{4}	1.26×10^{4}	7.49×10^{3}	1.21×10^{3}	5.98×10^{-6}	4.11×10^{-6}	1.33×10^{-6}	2.05×10^{-7}	1.48×10^{-8}	4.55×10^{-10}

Table C-5. Input for DEGADIS Simulation of a Vertical Wellhead Release

Value			Line Number
Release from a			1
Well Head:			2
Verticle Jet Simulation			3
			4
1.5	10.		5
0.1			6
1	6	0.	7
273.	1.	75.	8
273.			9
CPD			10
25.2			11
3,600.			12
273.			13
4.7×10^{-4}	1.0×10^{-4}	1.6	14
0	1,500.	0.0	15
0			16
7.69			17
5.0	0.0192		18
3,600.			19
50.			20

Line 18 contains the height of release (5 m) and the effective diameter (0.0192 m)

Line 19 is the duration of release, 3,600 s.

Line 20 is the distance between points at which DEGADIS calculates the output.

DEGADIS Output

A partial DEGADIS output is given in Table C-6. The first column gives the distance downwind and the second gives the elevation. As can be seen, the plume rises substantially because of its initial momentum. The third column gives the concentration of the released gas as a mole fraction, the fourth column gives the concentration in kg/m^3 and the fifth column gives the density in kg/m^3. As can be seen, the density rapidly approaches that of the surrounding air, 1.29 kg/m^3. The fifth column gives the temperature of the plume, which remains constant at 273K because the released plume and the air both have that temperature. The sixth column gives the plume horizontal standard deviation, σ y, and the seventh column gives the vertical standard deviation, σ z (the concentration across the plume is approximated by a Gaussian distribution in DEGADIS). As can be seen, at a height of 1.60 m, the predicted width of the plume (the distance across the wind to the upper or lower Levels of Concern, LC_{01} and ERPG-2) is zero so that LOCs are not predicted to be seen at ground level. This is a typical result for vertical jets of sour gas in stable weather conditions, whether DEGADIS, SLAB, or SAPLUME is used.

SAMPLE SAPLUME CALCULATIONS

SAPLUME Input

Table C-7 contains the input for the model SAPLUME corresponding to Table C-3, which contains the SLAB input for a horizontal release with composition D. The first few lines of input begin with four asterisks and are title cards, followed by a blank which tells the code that the titles have ended. Each subsequent line or group of lines begins with a keyword, followed by numbers in exponential notation to three significant figures.

"SITE" tells SAPLUME that there is a site with one radius and one sector (this is the default when the model is not considering a real site). The following line gives the one radius, arbitrarily set at 10,000 m, with one person arbitrarily set at that point (in the mode of operation chosen for the current problem, the model ignores these numbers).

"WEATHER" specifies that one weather condition only, category F, is being considered (because the 1.000 that follows WEATHER begins at space 61. For E the space would be 51, for D, 41 and so forth. The model can consider all six weather categories at once with up to four velocity subdivisions in each.) In this case, there is one velocity subdivision, specified as 1.5 m/s (first line after weather), and the probability that the wind blows into the one sector is unity (second line after weather).

Table C-6. Partial DEGADIS Output - Vertical Jet

Release from a Wellhead Pipeline Vertical Jet Simulation

Downwind Distance (m)	Elevation (m)	Mole Fraction	Concentration (kg/m³)	Density (kg/m³)	Temperature (K)	σ y (m)	σ x (m)	At z = 1.60 m: Mole Fraction	At z = 1.60 m: Width to mol%: 1.00×10^{-2} (m)	At z = 1.60 m: Width to mol%: 4.70×10^{-2} (m)	Maximum Mole Fraction	Elevation for Maximum Mole Fraction (m)
1.000×10^{-30}	5.15	1.00	1.13	1.13	273	1.060×10^{-2}	1.059×10^{-2}	.000	0	0	1.00	5.15
29.5	120.	8.279×10^{-4}	9.314×10^{-4}	1.29	273	12.1	12.0	.000	0	0	8.279×10^{-4}	120.
61.4	142.	5.644×10^{-4}	6.349×10^{-4}	1.29	273	16.0	15.6	.000	0	0	5.644×10^{-4}	142.
99.6	157.	4.254×10^{-4}	4.786×10^{-4}	1.29	273	19.2	18.4	.000	0	0	4.254×10^{-4}	157.
142.	169.	3.425×10^{-4}	3.853×10^{-4}	1.29	273	22.0	20.6	.000	0	0	3.425×10^{-4}	169.
191.	180.	2.832×10^{-4}	3.186×10^{-4}	1.29	273	24.6	22.4	.000	0	0	2.832×10^{-4}	180.
240.	188.	2.432×10^{-4}	2.736×10^{-4}	1.29	273	27.0	23.9	.000	0	0	2.432×10^{-4}	188.
289.	196.	2.140×10^{-4}	2.408×10^{-4}	1.29	273	29.2	25.2	.000	0	0	2.140×10^{-4}	196.
339.	202.	1.915×10^{-4}	2.155×10^{-4}	1.29	273	31.4	26.3	.000	0	0	1.915×10^{-4}	202.
389.	207.	1.736×10^{-4}	1.953×10^{-4}	1.29	273	33.4	27.2	.000	0	0	1.736×10^{-4}	207.
438.	212.	1.588×10^{-4}	1.786×10^{-4}	1.29	273	35.5	28.1	.000	0	0	1.588×10^{-4}	212.
488.	217.	1.464×10^{-4}	1.647×10^{-4}	1.29	273	37.5	28.8	.000	0	0	1.464×10^{-4}	217.
538.	221.	1.358×10^{-4}	1.528×10^{-4}	1.29	273	39.4	29.5	.000	0	0	1.358×10^{-4}	221.
588.	225.	1.267×10^{-4}	1.425×10^{-4}	1.29	273	41.4	30.1	.000	0	0	1.267×10^{-4}	225.
638.	228.	1.187×10^{-4}	1.335×10^{-4}	1.29	273	43.4	30.7	.000	0	0	1.187×10^{-4}	228.
688.	231.	1.116×10^{-4}	1.255×10^{-4}	1.29	273	45.3	31.2	.000	0	0	1.116×10^{-4}	231.
738.	234.	1.053×10^{-4}	1.185×10^{-4}	1.29	273	47.2	31.7	.000	0	0	1.053×10^{-4}	234.
787.	237.	9.965×10^{-5}	1.121×10^{-4}	1.29	273	49.2	32.2	.000	0	0	9.965×10^{-5}	237.
837.	240.	9.457×10^{-5}	1.064×10^{-4}	1.29	273	51.1	32.6	.000	0	0	9.457×10^{-5}	240.
887.	242.	8.995×10^{-5}	1.012×10^{-4}	1.29	273	53.1	33.0	.000	0	0	8.995×10^{-5}	242.
937.	245.	8.575×10^{-5}	9.647×10^{-5}	1.29	273	55.0	33.4	.000	0	0	8.575×10^{-5}	245.
987.	247.	8.190×10^{-5}	9.213×10^{-5}	1.29	273	56.9	33.8	.000	0	0	8.190×10^{-5}	247.
1.037×10^{3}	249.	7.836×10^{-5}	8.816×10^{-5}	1.29	273	58.9	34.2	.000	0	0	7.836×10^{-5}	249.
1.087×10^{3}	251.	7.510×10^{-5}	8.449×10^{-5}	1.29	273	60.8	34.5	.000	0	0	7.510×10^{-5}	251.
1.137×10^{3}	253.	7.208×10^{-5}	8.109×10^{-5}	1.29	273	62.7	34.9	.000	0	0	7.208×10^{-5}	253.
1.187×10^{3}	255.	6.928×10^{-5}	7.794×10^{-5}	1.29	273	64.7	35.2	.000	0	0	6.928×10^{-5}	255.
1.237×10^{3}	257.	6.667×10^{-5}	7.501×10^{-5}	1.29	273	66.6	35.5	.000	0	0	6.667×10^{-5}	257.
1.287×10^{3}	258.	6.424×10^{-5}	7.228×10^{-5}	1.29	273	68.5	35.8	.000	0	0	6.424×10^{-5}	258.
1.337×10^{3}	260.	6.197×10^{-5}	6.972×10^{-5}	1.29	273	70.5	36.1	.000	0	0	6.197×10^{-5}	260.
1.387×10^{3}	262.	5.984×10^{-5}	6.733×10^{-5}	1.29	273	72.4	36.3	.000	0	0	5.984×10^{-5}	262.

Table C-6 (cont)

Downwind Distance (m)	Elevation (m)	Mole Fraction	Concentration (kg/m^3)	Density (kg/m^3)	Temperature (K)	σ y (m)	σ z (m)	At z = 1.60 m: Mole Fraction	At z = 1.60 m: Width to mol%: 1.00×10^{-2} (m)	At z = 1.60 m: Width to mol%: 4.70×10^{-2} (m)	Maximum Mole Fraction	Elevation for Maximum Mole Fraction (m)
1.437×10^3	263.	5.785×10^{-5}	6.508×10^{-5}	1.29	273	74.3	36.6	.000	0	0	5.785×10^{-5}	263.
1.487×10^3	265.	5.597×10^{-5}	6.296×10^{-5}	1.29	273	76.3	36.9	.000	0	0	5.597×10^{-5}	265.
1.537×10^3	266.	5.420×10^{-5}	6.097×10^{-5}	1.29	273	78.2	37.1	.000	0	0	5.420×10^{-5}	266.
1.587×10^3	267.	5.253×10^{-5}	5.909×10^{-5}	1.29	273	80.2	37.4	.000	0	0	5.253×10^{-5}	267.
1.637×10^3	269.	5.095×10^{-5}	5.732×10^{-5}	1.29	273	82.1	37.6	.000	0	0	5.095×10^{-5}	269.
1.687×10^3	270.	4.945×10^{-5}	5.564×10^{-5}	1.29	273	84.0	37.9	.000	0	0	4.945×10^{-5}	270.
1.737×10^3	271.	4.804×10^{-5}	5.404×10^{-5}	1.29	273	85.9	38.1	.000	0	0	4.804×10^{-5}	271.
1.787×10^3	273.	4.669×10^{-5}	5.253×10^{-5}	1.29	273	87.9	38.3	.000	0	0	4.669×10^{-5}	273.
1.837×10^3	274.	4.542×10^{-5}	5.109×10^{-5}	1.29	273	89.8	38.6	.000	0	0	4.542×10^{-5}	274.
1.887×10^3	275.	4.420×10^{-5}	4.973×10^{-5}	1.29	273	91.7	38.8	.000	0	0	4.420×10^{-5}	275.
1.937×10^3	276.	4.304×10^{-5}	4.842×10^{-5}	1.29	273	93.7	39.0	.000	0	0	4.304×10^{-5}	276.
1.987×10^3	277.	4.194×10^{-5}	4.718×10^{-5}	1.29	273	95.6	39.2	.000	0	0	4.194×10^{-5}	277.
2.037×10^3	278.	4.089×10^{-5}	4.600×10^{-5}	1.29	273	97.5	39.5	.000	0	0	4.089×10^{-5}	278.
2.087×10^3	279.	3.988×10^{-5}	4.487×10^{-5}	1.29	273	99.4	39.7	.000	0	0	3.988×10^{-5}	279.
2.137×10^3	280.	3.892×10^{-5}	4.378×10^{-5}	1.29	273	101.	39.9	.000	0	0	3.892×10^{-5}	280.
2.187×10^3	281.	3.800×10^{-5}	4.275×10^{-5}	1.29	273	103.	40.1	.000	0	0	3.800×10^{-5}	281.
2.237×10^3	282.	3.711×10^{-5}	4.175×10^{-5}	1.29	273	105.	40.3	.000	0	0	3.711×10^{-5}	282.
2.287×10^3	283.	3.627×10^{-5}	4.080×10^{-5}	1.29	273	107.	40.5	.000	0	0	3.627×10^{-5}	283.
2.337×10^3	284.	3.546×10^{-5}	3.989×10^{-5}	1.29	273	109.	40.7	.000	0	0	3.546×10^{-5}	284.
2.387×10^3	285.	3.468×10^{-5}	3.901×10^{-5}	1.29	273	111.	40.9	.000	0	0	3.468×10^{-5}	285.
2.437×10^3	286.	3.393×10^{-5}	3.817×10^{-5}	1.29	273	113.	41.1	.000	0	0	3.393×10^{-5}	286.
2.487×10^3	286.	3.321×10^{-5}	3.736×10^{-5}	1.29	273	115.	41.2	.000	0	0	3.321×10^{-5}	286.
2.537×10^3	287.	3.252×10^{-5}	3.658×10^{-5}	1.29	273	117.	41.4	.000	0	0	3.252×10^{-5}	287.
2.587×10^3	288.	3.185×10^{-5}	3.583×10^{-5}	1.29	273	119.	41.6	.000	0	0	3.185×10^{-5}	288.
2.637×10^3	289.	3.121×10^{-5}	3.511×10^{-5}	1.29	273	120.	41.8	.000	0	0	3.121×10^{-5}	289.
2.687×10^3	290.	3.059×10^{-5}	3.441×10^{-5}	1.29	273	122.	42.0	.000	0	0	3.059×10^{-5}	290.
2.737×10^3	290.	2.999×10^{-5}	3.374×10^{-5}	1.29	273	124.	42.2	.000	0	0	2.999×10^{-5}	290.
2.787×10^3	291.	2.941×10^{-5}	3.309×10^{-5}	1.29	273	126.	42.3	.000	0	0	2.941×10^{-5}	291.
2.837×10^3	292.	2.885×10^{-5}	3.246×10^{-5}	1.29	273	128.	42.5	.000	0	0	2.885×10^{-5}	292.
2.887×10^3	293.	2.831×10^{-5}	3.185×10^{-5}	1.29	273	130.	42.7	.000	0	0	2.831×10^{-5}	293.
2.937×10^3	293.	2.779×10^{-5}	3.127×10^{-5}	1.29	273	132.	42.9	.000	0	0	2.779×10^{-5}	293.
2.987×10^3	294.	2.729×10^{-5}	3.070×10^{-5}	1.29	273	134.	43.0	.000	0	0	2.729×10^{-5}	294.
3.037×10^3	295.	2.680×10^{-5}	3.015×10^{-5}	1.29	273	136.	43.2	.000	0	0	2.680×10^{-5}	295.

Table C-6 (cont)

Downwind Distance (m)	Elevation (m)	Mole Fraction	Concentration (kg/m^3)	Density (kg/m^3)	Temperature (K)	σy (m)	σz (m)	At z = 1.60 m: Mole Fraction	At z = 1.60 m: Width to mol%: 1.00×10^{-2} (m)	At z = 1.60 m: Width to mol%: 4.70×10^{-2} (m)	Maximum Mole Fraction	Elevation for Maximum Mole Fraction (m)
3.087×10^3	295.	2.633×10^{-5}	2.962×10^{-5}	1.29	273	138.	43.4	.000	0	0	2.633×10^{-5}	295.
3.137×10^3	296.	2.588×10^{-5}	2.911×10^{-5}	1.29	273	139.	43.5	.000	0	0	2.588×10^{-5}	296.
3.187×10^3	297.	2.543×10^{-5}	2.861×10^{-5}	1.29	273	141.	43.7	.000	0	0	2.543×10^{-5}	297.
3.237×10^3	297.	2.500×10^{-5}	2.813×10^{-5}	1.29	273	143.	43.9	.000	0	0	2.500×10^{-5}	297.
3.262×10^3	297.	2.479×10^{-5}	2.789×10^{-5}	1.29	273	144.	43.9	.000	0	0	2.479×10^{-5}	297.

The entries on the "PROPERTIES" line are as follows: the ambient temperature is 273K at which temperature the density of air is 1.29 kg/m^3 and its specific heat at constant pressure is 990 J/kg/K. At a temperature of 273K, the density of the released gas is 1.141 kg/m^3 and the specific heat at constant pressure is 1,500 J/kg/K.

The entries on the "SOURCE" line are as follows: the rate of release is 7.69 kg/m^3 at a temperature of 273K. The amount of air initially entrained with the source is zero. The angle of release is zero radians (horizontal). The height of release is 5 m. The initial momentum flux is 2,540 kg m s^{-2} and is the product of the rate of release and the exit velocity (the speed of sound is approximately 330 m/s).

The "INTERVAL" line specifies that SAPLUME calculations start at a downwind distance x of 0.1 m and that calculations are performed at a uniform spacing of 0.15 in $\log_{10}(x)$.

On the "ROUG" line, the surface roughness length is 0.1 m and the windspeed is measured at a height of 10 m.

The "HAZARD" line specifies two levels of concern. As explained above in the discussion of the SLAB results, these are the LC_{01} of 470 ppm (approximately 5.32×10^{-4} kg/m^3) and the ERPG-2 of 100 ppm (1.141×10^{-4} kg/m^3).

"VGRAD" informs SAPLUME that it should consider the velocity gradient and the temperature gradient in the atmosphere. SAPLUME uses standard textbook formulae for these gradients. If the first entry after VGRAD were zero, velocity would be constant as a function of height. Similarly, if the second entry after VGRAD were zero, the temperature of the atmosphere would remain constant as height increases.

A value of 3 after "NEUT" specifies one of three parametrizations for the standard deviations in the Gaussian model once the released material has evolved out of the jet phase. NEUT =3 corresponds to a parameterization that is appropriate for a rural site. "DUR" specifies that the duration of release is one hour.

Finally, the repetition of "END" terminates the run of SAPLUME.

SAPLUME Output

A partial SAPLUME output corresponding to the input in Table C-7 is given in Table C-8. This table indicates that, for hazard level 1 (i.e., the LC_{01} of 470 ppm discussed above) the plume touches down at a downwind distance of approximately 63 m and extends to about 3 km, covering an area of about 10^5 m^2 (one tenth of a square kilometer). The table of pairs of values of downwind distance, x, and width can be coupled to a plotting routine to give contours of constant concentration. Similarly, hazard level 2 (the ERPG-2 of 100 ppm)

Table C-7. Input for SAPLUME Runs

****	EPA Hydrogen Sulfide Runs					
****	January 1993					
****	No Protective Measures					
****	Composition D - 30% H_2S at Wellhead					
****	$2x10^7$ SCFD:					
****	Horizontal Release					
****	H_2S Release Rate - 3.073 kg/s					
****	Total Mixture Release Rate - 7.69 kg/s					
****	Hazard Level - ERPG-2 (100 ppm) and					
****	LC_{01} (470 ppm) Both Adjusted for Stream Composition					
****	Category F Weather, Windspeed 1.5 m/s					
SITE	1.000 1.000					
$1.000x10^4$						
1.000						
WEATHER	1.000					
1.500						
$2.500x10^{-1}$						
PROP	$2.730x10^2$	1.290	$9.900x10^2$	$2.730x10^2$	1.141	$1.500x10^3$
SOURCE	7.690	$2.730x10^2$	0.000	0.000	5.000	$2.540x10^3$
INTERVAL	$1.000x10^{-1}$	$1.5000x10^{-1}$				
ROUG	$1.0000x10^{-1}$	$1.000x10^1$				
HAZARD	2.000					
$5.320x10^{-4}$	$1.141x10^{-4}$					
VGRAD	1.000 1.000					
NEUT	3.000					
DUR	1.000					
END						
END						

Table C-8. Partial SAPLUME Output for Horizontal Plume

FOR HAZARD LEVEL 1, WINDSPEED 1.500 m/s AND CATEGORY 6

THE HAZARDOUS CLOUD EXTENDS FROM 6.327×10^{1} TO 3.126×10^{3} METERS DOWNWIND AND HAS AN AREA OF 1.129×10^{5} m^2

CLOUD BOUNDARIES

X[a] (m)	WIDTH (m)	X (m)	WIDTH (m)	X (m)	WIDTH (m)	X (m)	WIDTH (m)	X (m)	WIDTH (m)
0.000	0.000	1.000×10^{-1}	0.000	1.162×10^{-1}	0.000	1.350×10^{-1}	0.000	1.568×10^{-1}	0.000
1.822×10^{-1}	0.000	2.117×10^{-1}	0.000	2.460×10^{-1}	0.000	2.858×10^{-1}	0.000	3.320×10^{-1}	0.000
3.857×10^{-1}	0.000	4.482×10^{-1}	0.000	5.207×10^{-1}	0.000	6.050×10^{-1}	0.000	7.029×10^{-1}	0.000
8.166×10^{-1}	0.000	9.488×10^{-1}	0.000	1.102	0.000	1.281	0.000	1.488	0.000
1.729	0.000	2.009	0.000	2.334	0.000	2.711	0.000	3.150	0.000
3.660	0.000	4.252	0.000	4.940	0.000	5.740	0.000	6.669	0.000
7.748	0.000	9.002	0.000	1.046×10^{1}	0.000	1.215×10^{1}	0.000	1.412×10^{1}	0.000
1.640×10^{1}	0.000	1.906×10^{1}	0.000	2.214×10^{1}	0.000	2.572×10^{1}	0.000	2.989×10^{1}	0.000
3.472×10^{1}	0.000	4.034×10^{1}	0.000	4.687×10^{1}	0.000	5.446×10^{1}	0.000	6.327×10^{1}	5.555
7.351×10^{1}	2.627	8.540×10^{1}	2.739	9.922×10^{1}	2.955	1.153×10^{2}	3.294	1.339×10^{2}	3.768
1.556×10^{2}	4.385	1.808×10^{2}	5.149	2.101×10^{2}	6.066	2.441×10^{2}	7.143	2.835×10^{2}	8.388
3.294×10^{2}	9.811	3.827×10^{2}	1.142×10^{1}	4.447×10^{2}	1.324×10^{1}	5.167×10^{2}	1.527×10^{1}	6.003×10^{2}	1.701×10^{1}
6.974×10^{2}	1.856×10^{1}	8.103×10^{2}	2.005×10^{1}	9.414×10^{2}	2.140×10^{1}	1.094×10^{3}	2.257×10^{1}	1.271×10^{3}	2.345×10^{1}
1.476×10^{3}	2.393×10^{1}	1.715×10^{3}	2.384×10^{1}	1.993×10^{3}	2.295×10^{1}	2.315×10^{3}	2.082×10^{1}	2.690×10^{3}	1.653×10^{1}
3.126×10^{3}	5.139								

[a] x = Downwind distance.

extends from about 60 m to about 12 km downwind, covering an area of approximately 10^6 m^2.

The above results are close to those predicted by SLAB. The higher result is about 50% larger than that predicted by SLAB. However, the difference is within the range of uncertainties expected for these dispersion models. As noted above, the neglect of dry deposition means that the predictions are likely to be conservative.

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16. ABSTRACT

Under section 112(n)(5) of the Clean Air Act Amendments of 1990, the EPA is required to submit this report which assesses the hazards to public health and the environment resulting from the emission of hydrogen sulfide associated with the extraction of oil and natual gas. This assessment is designed to build upon work done under section 8002(m) of the Solid Waste Disposal Act and to reflect consultation with the States. The report includes a review of existing State and industry control standards, techniques, and enforcement and includes recommendations for control of hydrogen sulfide emissions from these sources.

The Office of Air Quality Planning and Standards and the Office of Solid Waste and Emergency Response completed this report on a joint effort. This report provides the information currently available on each of the elements listed above.

17. KEY WORDS AND DOCUMENT ANALYSIS

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HYDROGEN SULFIDE:
EVALUATION OF CURRENT CALIFORNIA AIR QUALITY STANDARDS WITH RESPECT TO PROTECTION OF CHILDREN

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Prepared for
California Air Resources Board
California Office of Environmental Health Hazard Assessment

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A. Extended abstract

The current California Ambient Air Quality Standard (CAAQS) for hydrogen sulfide is 0.03 ppm (30 ppb, 42 µg/m^3) for one hour. The standard was adopted in 1969 and was based on the geometric mean odor threshold measured in adults. The purpose of the standard was to decrease odor annoyance. The standard was reviewed in 1980 and 1984 (CARB, 1984), and was not changed since no new relevant information had emerged. The U.S. EPA presently does not classify hydrogen sulfide as either a criteria air pollutant or a Hazardous Air Pollutant. However, several countries have short-term (usually 30 minute) standards for hydrogen sulfide, as well as long-term (24 hour) standards.

This report focuses on key studies in humans and animals bearing on the health-protectiveness of the CAAQS for hydrogen sulfide. It also includes a discussion of whether significant adverse health effects would reasonably be expected to occur, especially among infants and children, at exposure concentrations below the CAAQS of 30 ppb, based on the findings of published studies. Additional research on odor sensitivity in infants, children, and adults would be useful in evaluating the standard. This would include: (1) testing of the odor threshold for H_2S using the most current methodology among groups of healthy persons of both sexes in different age ranges; (2) odor testing of hydrogen sulfide in adolescents or younger children to determine their odor threshold for H_2S; (3) the identification of children hypersensitive to the odor of hydrogen sulfide; and (4) physiologic testing of anosmic (either specifically anosmic to H_2S or totally anosmic) children at the CAAQS to determine if adverse physiological symptoms occur in the absence of odor detection.

B. Background

The Mulford-Carrell Air Resources Act of 1967 directed the Air Resources Board to divide California into Air Basins and to adopt ambient air quality standards for each basin (Health and Safety Code (H&SC) Section 39606). The existing California state-wide ambient air quality standard (CAAQS) for hydrogen sulfide of 0.03 ppm (30 ppb, 42 $\mu g/m^3$), averaged over a period of 1 hour and not to be equaled or exceeded, protects against nuisance odor ("rotten egg smell") for the general public. The standard was adopted in 1969 and was based on rounding of the geometric mean odor threshold of 0.029 ppm (range = 0.012 – 0.069 ppm; geometric SD = 0.005 ppm) measured in adults (California State Department of Public Health, 1969). The standard was reviewed by the Department of Health Services in 1980 and 1984, and was not changed since no new relevant information had emerged. OEHHA (1999) formally adopted 30 ppb as the acute Reference Exposure Level (REL) for use in evaluating peak off-site concentrations from industrial facilities subject to requirements in H&SC Section 44300 *et seq*. OEHHA (2000) adopted a level of 8 ppb (10 $\mu g/m^3$) as the chronic Reference Exposure Level (cREL) for use in evaluating long term emissions from Hot Spots facilities. The cREL was based on a study demonstrating nasal histological changes in mice.

At the federal level, U.S. EPA does not currently classify hydrogen sulfide as either a criteria air pollutant or a Hazardous Air Pollutant (HAP). U.S. EPA has developed a (chronic) Reference Concentration (RfC) of 0.001 mg/m^3 (1 $\mu g/m^3$) for hydrogen sulfide (USEPA, 1999). The RfC is an estimate (with uncertainty spanning perhaps an order of magnitude) of a daily inhalation exposure of the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime.

There are no international standards for H_2S. Many countries have "short-term" (usually 30 minute) standards, which range from 6 to 210 ppb (WHO, 1981). The World Health Organization (WHO) recommends that, in order to avoid substantial complaints about odor annoyance among the exposed population, hydrogen sulfide concentrations should not be allowed to exceed 0.005 ppm (5 ppb; 7 $\mu g/m^3$), with a 30-minute averaging time (WHO, 1981; National Research Council, 1979; Lindvall, 1970). A very short-lived, peak concentration could also be annoying. Rule 2 of Regulation 9 of the Bay Area Air Quality Management District (BAAQMD) specifies that ambient ground level H_2S concentrations may not exceed 60 ppb averaged over 3 consecutive minutes. Regulating at averaging times less than 30 – 60 minutes may be difficult. Many countries have "long-term" (24 hour) standards (WHO, 1981).

NRC (1979), WHO (1981), Beauchamp *et al*. (1984), Reiffenstein *et al*. (1992), and ATSDR (1999) have published reviews of the health effects of hydrogen sulfide.

C. Principal sources/Exposure assessment

Hydrogen sulfide (H_2S) is used as a reagent and as an intermediate in the preparation of other reduced sulfur compounds (HSDB, 1999). It is also a by-product of desulfurization processes in the oil and gas industries and rayon production, sewage treatment, and leather tanning (Ammann, 1986). Geothermal power plants, petroleum production and refining, and sewer gas are specific sources of hydrogen sulfide in California. The annual statewide industrial emissions from facilities reporting under the Air Toxics Hot Spots Information and Assessment Act in California (H&SC Sec. 44300 *et seq*.), based on the most recent inventory, were estimated to be 5,688,172 pounds of hydrogen sulfide (CARB, 1999).

A specific concern in California has been schools located near workplaces emitting toxic substances. For example, the Hillcrest Elementary School in Rodeo (Contra Costa County; part of the BAAQMD) is adjacent to an oil refinery which, on occasion, has emitted enough malodorous sulfur compounds (including H_2S) for the school to close its doors and for the teachers and children to "shelter-in-place." Thus the school district has planned to relocate the school (West County Times, November 23, 1999). These compounds have also affected other schools in the area.

Hydrogen sulfide is produced endogenously in mammalian tissues from L-cysteine, mainly by two pyridoxal-5'-phosphate-dependent enzymes, cystathionine beta-synthetase and cystathionine gamma-lyase (Hosoki *et al*., 1997). Abe and Kimura (1996) suggested that hydrogen sulfide may be an endogenous neuromodulator in the hippocampus based on the high level of cystathionine beta-synthetase in the hippocampus and on experimental effects of activators and inhibitors of the enzyme.

D. Key studies of acute and chronic health impacts

D.1. Toxicity to Humans

D.1.1. Adults. Hydrogen sulfide is an extremely hazardous gas (ACGIH, 1991). Exposure to high concentrations of hydrogen sulfide is reported to be the most common cause of sudden death in the workplace (NIOSH, 1977). Estimates of the mortality resulting from acute hydrogen sulfide intoxication include 2.8% (Arnold *et al*., 1985) and 6% (WHO, 1981). While severe intoxication is especially of concern when exposure occurs in confined spaces, an accidental release of hydrogen sulfide into the ambient air surrounding industrial facilities can cause very serious effects. As a result of an accidental release of hydrogen sulfide due to a malfunctioning flare at an oilfield at Poza Rica, Mexico in 1950, 320 people were hospitalized and 22 died (WHO, 1981).

Most information on H_2S toxicity comes from studies that used levels of H_2S orders of magnitude above the standard of 0.03 ppm. Hazardtext (1994) reported an inhalation LC_{Lo} of 600 and 800 ppm (840 and 1,120 mg/m^3) for 30 and 5 minutes, respectively. A lethal exposure was documented for a worker exposed to approximately 600 ppm H_2S for 5 to 15 minutes (Simson and Simpson, 1971). Inhalation of 1,000 ppm (1,400 mg/m^3) is reported to cause immediate respiratory arrest (ACGIH, 1991). Concentrations greater than 200 ppm (280 mg/m^3) H_2S are reported to cause direct irritant effects on exposed surfaces and can cause pulmonary edema following longer exposures (Spiers and Finnegan, 1986). The mechanism of H_2S

toxicity, cellular hypoxia caused by inhibition of cytochrome oxidase, is similar to that for cyanide. Toxicity can be treated by induction of methemoglobin or by therapy with hyperbaric oxygen (Elovaara *et al*., 1978; Hsu *et al*., 1987).

At concentrations exceeding 50 ppm (70 mg/m³) H_2S, olfactory fatigue prevents detection of H_2S odor. Exposure to 100-150 ppm (140-210 mg/m³) for several hours causes local irritation (Haggard, 1925). Exposure to 50 ppm for 1 hour causes conjunctivitis with ocular pain, lacrimation, and photophobia; this can progress to keratoconjunctivitis and vesiculation of the corneal epithelium (ACGIH, 1991).

Bhambhani and Singh (1985) reported that exposure of 42 individuals to 2.5 to 5 ppm (3.5 to 7 mg/m³) H_2S caused coughing and throat irritation after 15 minutes. Bhambhani and Singh (1991) showed that 16 healthy adult male subjects (25.2±5.5 years old) exposed to 5 ppm (7 mg/m³) H_2S under conditions of moderate exercise exhibited impaired lactate and oxygen uptake in the blood. Subsequently Bhambani *et al*. (1994) compared the effects of inhaling 5 ppm H_2S on physiological and hematological responses during exercise. Subjects were 13 men (mean±SD for age, height, and weight = 24.7±4.6 y, 173±6.6 cm, and 73.1±8.1 kg, respectively) and 12 women (mean±SD = 22.0±2.1 y, 165±8.2 cm, and 63.4±8.6 kg, respectively). Subjects completed two 30-minute exercise tests on a cycle ergometer at 50% of their predetermined maximal aerobic power, while breathing either air or 5 ppm H_2S. There were no significant differences between the two exposures for metabolic (oxygen uptake, carbon dioxide production, respiratory exchange ratio), cardiovascular (heart rate, blood pressure, rate pressure product), arterial blood (oxygen and carbon dioxide tensions, pH), and perceptual (rating of perceived exertion) responses. No one reported adverse health effects following H_2S exposure. The authors believe that healthy adults can safely perform moderate intensity work in environments containing 5 ppm H_2S.

Bhambhani *et al*. (1996) examined the acute effects of "oral" inhalation of 10-ppm H_2S, the occupational exposure limit, on lung physiology as measured by pulmonary function in nine men and ten women. The volunteers inhaled medical air or 10 ppm H_2S through the mouth for 15 minutes each during cycle exercise at 50% of their maximal aerobic power. Routine pulmonary function tests (FVC, FEV_1, FEV_1/FVC, PEFR, maximal ventilation volume, and DL_{CO}) were administered at rest and immediately after the two exposure conditions. There were no significant changes in any of the variables derived from the flow volume loop, maximum ventilation volume, and diffusion capacity of the lung for carbon monoxide (DL_{CO}) in both genders. No subject experienced any sign or symptom as a result of H_2S. The authors concluded that inhalation of 10 ppm H_2S through the mouth at an elevated metabolic and ventilation rate does not significantly alter pulmonary function in healthy people.

Jappinen *et al*. (1990) exposed ten adult asthmatic volunteers to 2 ppm H_2S for 30 minutes and tested pulmonary function. All subjects reported detecting "very unpleasant" odor but "rapidly became accustomed to it." Three subjects reported headache following exposure. No significant changes in mean FVC or FEV_1 were reported. Although individual values for specific airway resistance (SR_{aw}) were not reported, the difference following exposure ranged from –5.95% to +137.78%. The decrease in specific airway conductance, SG_{aw}, ranged from –57.7% to +28.9%. The increase in mean SR_{aw} and the decrease in mean SG_{aw} were not statistically significant for the entire group. However, markedly (>30%) increased airway resistance and decreased airway conductance were noted in two of the ten asthmatic subjects at 2 ppm, which indicated bronchial obstruction and may be clinically important. Two ppm is 67 times the CAAQS of 0.03 ppm.

Hydrogen sulfide is noted for its strong and offensive odor. The existing CAAQS of 0.03 ppm (30 ppb, 42 $\mu g/m^3$) for 1 hour is based on rounding the geometric mean odor detection threshold of 0.029 ppm (range = 0.012 – 0.069 ppm; GSD = 0.005 ppm). The threshold was determined for a panel of 16 presumably healthy adults (California State Department of Public Health, 1969). No information on the sex or age of the panel members has been located. Amoore (1985) reviewed 26 studies, published between 1848 and 1979, all of which reported average odor detection thresholds for H_2S. The 26 studies seem to be mainly controlled exposures and used various measurement methods. They included (1) at least two studies using only one subject, (2) a study of a panel of 35 people testing odors in natural gas in Southern California, and (3) another study of 852 untrained young adults (age range = 17.5 – 22.4 years) tested at county and state fairs in the Northwest. The average odor detection threshold in the 26 studies ranged from 0.00007 to 1.4 ppm H_2S. The geometric mean of the 26 studies was 0.008 ppm (8 ppb), approximately one-fourth the value determined by the Department of Public Health and lower than the lowest individual threshold of 12 ppb measured in the California panel. Surprisingly the Department of Public Health panel study was <u>not</u> one of the 26 studies used by Amoore and was not even mentioned in his 1985 report to the ARB.

Venstrom and Amoore (1968) reported that, in general, olfactory sensitivities decrease by a factor of 2 for each 22 years of age above age 20. The conclusion was based on a study of 18 odorants in 97 government laboratory workers, ages 20 through 70. Hydrogen sulfide was not tested. The geometric mean odor threshold of 8 ppb for H_2S from the 26 studies is based on an average age of 40 (possibly assumed to be the age of an average adult). Amoore (1985) estimated that an 18-year-old person would have a threshold of 4 ppb H_2S, while a 62-year-old person was predicted to have a threshold of 16 ppb. Amoore also stated that there was no noticeable trend of odor sensitivity between young adults and children down to 5 years but did not present specific data to support the statement.

Concentrations, which substantially exceed the odor threshold for, result in the annoying and discomforting physiological symptoms of headache or nausea (Amoore, 1985; Reynolds and Kauper 1984). The perceived intensity of the odor of H_2S depends on the longevity of the concentration, and the intensity increases 20% for each doubling of the concentration (Amoore, 1985). Several studies have been conducted to establish the ratio of discomforting annoyance threshold to detection threshold for unpleasant odors (Winkler, 1975; Winneke and Kastka, 1977; Hellman and Small, 1974; Adams *et al.,* 1968; and NCASI, 1971). The geometric mean for these studies is 5; therefore an unpleasant odor should result in annoying discomfort when it reaches an average concentration of 5 times its detection threshold. (Two studies that tested only H_2S had a geometric mean of 4.) Applying the 5-fold multiplier to the mean detectable level of 8 ppb results in a mean annoyance threshold of 40 ppb. Amoore (1985) estimates that at 30 ppb, the CAAQS, H_2S would be detectable by 83% of the population and would be discomforting to 40% of the population (Table 1). These "theoretical" estimates have been substantiated by odor complaints and reports of nausea and headache (Reynolds and Kauper 1984) at 30 ppb H_2S exposures from geyser emissions.

In order to avoid substantial complaints about odor annoyance among the exposed population, the World Health Organization (WHO) recommends that hydrogen sulfide concentrations should not exceed 0.005 ppm (5 ppb; 7 $\mu g/m^3$), with a 30-minute averaging time (WHO, 1981; National Research Council, 1979; Lindvall, 1970). The WHO task group believed that 5 ppb averaged over 30 minutes "should not produce odour nuisance in most situations."

Table 1. Predicted effects of exposure to ambient H_2S. (Adapted from Amoore, 1985)

H_2S (ppb)	% able to detect odor[a]	Perceived odor intensity[b] (ratio)	Median odor units[c]	% annoyed by odor[d]
200	99	2.31	25	88
100	96	1.93	12	75
50	91	1.61	6.2	56
40	88	1.52	5.0	50
35	87	1.47	4.4	47
30 (CAAQS)	83	1.41	3.7	40
25	80	1.34	3.1	37
20	74	1.27	2.5	31
15	69	1.18	1.9	22
10	56	1.06	1.2	17
8	50	1.00	1.00	11
6	42	0.93	0.75	8
4	30	0.83	0.50	5
2	14	0.70	0.25	2
1	6	0.58	0.12	1
0.5	2	0.49	0.06	0

[a]Based on mean odor detection threshold of 8.0 ppb and SD±2.0 binary steps
[b] Based on intensity exponent of 0.26 (Lindvall, 1974).
[c]H_2S concentration divided by mean odor detection threshold of 8 ppb.
[d] Based on assumption that mean annoyance threshold is 5x the mean odor detection threshold, and SD±2.0 binary steps.

Kilburn and Warshaw (1995) investigated whether people exposed to sulfide gases, including H_2S, as a result of working at or living downwind from the processing of "sour" crude oil demonstrated persistent neurobehavioral dysfunction. They studied 13 former workers and 22 neighbors of a California coastal oil refinery who complained of headaches, nausea, vomiting, depression, personality changes, nosebleeds, and breathing difficulties. Neurobehavioral functions and a profile of mood states were compared to 32 controls matched for age and educational level. The exposed subjects' mean values were statistically significantly different (abnormal) compared to controls for several tests (two-choice reaction time; balance (as speed of sway); color discrimination; digit symbol; trail-making A and B; immediate recall of a story). Their profile of mood states (POMS) scores were much higher than those of controls. Test scores for anger, confusion, depression, tension-anxiety, and fatigue were significantly elevated and nearly identical in both exposed residents and former workers, while the scores for controls equaled normal values from other published studies. Visual recall was significantly impaired in neighbors, but not in the former workers. Limited off-site air monitoring (one week) in the neighborhood found average levels of 10 ppb H_2S (with peaks of 100 ppb), 4 ppb dimethylsulfide, and 2 ppb mercaptans. On-site levels were much higher. The authors concluded that neurophysiological abnormalities were associated with exposure to reduced sulfur gases, including H_2S from crude oil desulfurization.

D.1.2. Children. In a case report Gaitonde *et al*. (1987) described subacute encephalopathy, ataxia, and choreoathetoid (jerky, involuntary) responses in a 20-month-old child with long term (approximately one year) exposure to hydrogen sulfide from a coal mine. Levels of up to at least 0.6 ppm (600 ppb) were measured and levels were possibly higher before measurements started. The abnormalities resolved after the emission source ceased operation.

As part of the South Karelia Air Pollution Study in Finland (Jaakkola *et al*., 1990), Marttila *et al*. (1994) assessed the role of long-term exposure to ambient air malodorous sulfur compounds released from pulp mills as a determinant of eye and respiratory symptoms and headache in children. The parents of 134 children living in severely polluted (n = 42), moderately polluted (n = 62), and rural, non-polluted (n = 30) communities responded to a cross-sectional questionnaire (response rate = 83%). In the severely polluted area, the annual mean concentrations of hydrogen sulfide and methyl mercaptan (H_3CSH) were estimated to be 8 $\mu g/m^3$ (6 ppb) and 2 - 5 $\mu g/m^3$ (1.4 – 3.6 ppb), respectively. The highest daily average concentrations were 100 $\mu g/m^3$ (71 ppb) and 50 $\mu g/m^3$ (36 ppb), respectively. The adjusted odds ratios (OR) for symptoms experienced during the previous 4 weeks and 12 months in the severely versus the non-polluted community were estimated in logistic regression analysis controlling for age and gender. The risks of nasal symptoms, cough, eye symptoms, and headache were increased in the severely polluted community, but did not reach statistical significance (Table 2). In addition, OEHHA staff noted that the highest percentages of children with symptoms were in the moderately polluted community, not in the severely polluted community. The authors concluded that exposure to malodorous sulfur compounds may affect the health of children. The odor threshold for methyl mercaptan of 1.6 ppb (Amoore and Hautala, 1983) indicates that it also likely contributed to the odor and probably the symptoms.

Table 2. Symptoms Reported in Marttila *et al*. (1994)

Symptom	*Time*	*Odds Ratio*	*95% CI*	*Time*	*Odds ratio*	*95%CI*
nasal symptoms	4 weeks	1.40	0.59-3.31	12 months	2.47	0.93-6.53
cough	4 weeks	1.83	0.75-4.45	12 months	2.28	0.95-5.47
eye symptoms	NR	NR	NR	12 months	1.15	0.43-3.05
headache	NR	1.02	0.36-2.94	12 months	1.77	0.69-4.54

NR = not reported

Studies of controlled exposures in children to study H_2S odor detection have not been located. A recent report studying children concluded that children aged 8 to 14 years have equivalent odor sensitivity to young adults (Cain *et al*., 1995), although children lack knowledge to identify specific odors by name. Koelega (1994) found that prepubescent children (58 nine-year-olds) were inferior in their detection of 4 of 5 odors compared to 15-year-olds (n = 58) and 20-year-olds (n = 112). Schmidt and Beauchamp (1988) have even tested 3-year-olds (n = 16) for sensitivity to noxious chemicals, such as butyric acid and pyridine.

In March-April 1983, 949 cases (including 727 in adolescent females) of acute non-fatal illness consisting of headache, dizziness, blurred vision, abdominal pain, myalgia, and fainting occurred at schools on the West Bank. However, physical examinations and biochemical tests were normal. There was no common exposure to food, drink, or agricultural chemicals among those affected. No toxins were consistently present in patients' blood or urine. The only environmental toxicant detected was H_2S gas in low concentrations (40 ppb) in a schoolroom at the site of the first outbreak (from a faulty latrine in the schoolyard). The illness was deemed to be psychogenic and possibly triggered by the smell of H_2S (Landrigan and Miller , 1983; Modan *et al*., 1983).

D.1.3. Development. Xu *et al*. (1998) conducted a retrospective epidemiological study in a large petrochemical complex in Beijing, China in order to assess the possible association between petrochemical exposure and spontaneous abortion. The facility consisted of 17 major production plants divided into separate workshops, which allowed for the assessment of exposure to specific chemicals. Married women (n = 2,853), who were 20-44 years of age, had never smoked, and who reported at least one pregnancy during employment at the plant, participated in the study. According to their employment record, about 57% of these workers reported occupational exposure to petrochemicals during the first trimester of their pregnancy. There was a significantly increased risk of spontaneous abortion for women working in all of the production plants with frequent exposure to petrochemicals compared with those working in non-chemical plants. Also, when a comparison was made between exposed and non-exposed groups within each plant, exposure to petrochemicals was consistently associated with an increased risk of spontaneous abortion (overall odds ratio (OR) = 2.7 (95% confidence interval (CI) = 1.8 to 3.9) after adjusting for potential confounding factors). Using exposure information obtained from interview responses for (self-reported) exposures, the estimated OR for spontaneous abortions was 2.9 (95% CI = 2.0 to 4.0). When the analysis was repeated by excluding 452 women who provided inconsistent reports between recalled exposure and work history, a comparable risk of spontaneous abortion (OR 2.9; 95% CI = 2.0 to 4.4) was found. In analyses for exposure to specific chemicals, an increased risk of spontaneous abortion was found with exposure to most chemicals. There were 106 women (3.7% of the study population) exposed only to hydrogen sulfide; the results for H_2S (OR 2.3; 95% CI = 1.2 to 4.4) were statistically significant. Unfortunately H_2S exposure concentrations were not reported.

D.2. Effects of Animal Exposure

D.2.1. Adult/mature animals. A median lethal concentration (LC_{50}) in rats exposed to H_2S for 4 hours was estimated as 440 ppm (616 mg/m³) (Tansy *et al*., 1981). An inhalation LC_{Lo} of 444 ppm for an unspecified duration is reported in rats, and a lethal concentration of 673 ppm (942 mg/m³) for 1 hour is reported in mice (RTECS, 1994). In another study, mortality was significantly higher for male rats (30%), compared to females (20%), over a range of exposure times and concentrations (Prior *et al*., 1988). A concentration of 1,000 ppm (1,400 mg/m³) caused respiratory arrest and death in dogs after 15-20 minutes (Haggard and Henderson, 1922). Inhalation of 100 ppm (140 mg/m³) for 2 hours resulted in altered leucine incorporation into brain proteins in mice (Elovaara *et al*., 1978). Kosmider *et al*. (1967) reported abnormal electrocardiograms in rabbits exposed to 100 mg/m³ (71 ppm) H_2S for 1.5 hours.

Khan *et al*. (1990) exposed groups of 12 male Fischer 344 rats to 0, 10, 50, 200, 400, or 500-700 ppm hydrogen sulfide for 4 hours. Four rats from each group were euthanized at 1, 24, or 48 hours post-exposure. The activity of cytochrome c oxidase in lung mitochondria, a primary molecular target of H_2S, was significantly ($p<0.05$) decreased at 50 ppm (15%), 200 ppm (43%), and 400 ppm (68%) at 1-hour post-exposure compared to controls. A NOAEL of 10 ppm for inhibition of cytochrome c oxidase was identified in this study.

Fischer and Sprague-Dawley rats (15 per group) were exposed to 0, 10.1, 30.5, or 80 ppm (0, 14.1, 42.7, or 112 mg/m^3, respectively) H_2S for 6 hours/day, 5 days/week for 90 days (CIIT, 1983a,b). Measurements of neurological and hematological function revealed no abnormalities due to H_2S exposure. Histological examination of the nasal turbinates also revealed no significant exposure-related changes. A significant decrease in body weight was observed in both strains of rats exposed to 80 ppm (112 mg/m^3).

In a companion study, the CIIT conducted a 90-day inhalation study in mice (10 or 12 mice per group) exposed to 0, 10.1, 30.5, or 80 ppm (0, 14.1, 42.7, or 112 mg/m^3, respectively) H_2S for 6 hours/day, 5 days/week (CIIT, 1983c). Neurological function was measured by tests for posture, gait, facial muscle tone, and reflexes. Ophthalmologic and hematologic examinations were also performed, and a detailed necropsy was included at the end of the experiment. The only exposure-related histological lesion was inflammation of the nasal mucosa of the anterior segment of the noses of mice exposed to 80 ppm (112 mg/m^3) H_2S. Weight loss was also observed in the mice exposed to 80 ppm. Neurological and hematological tests revealed no abnormalities. The 30.5 ppm (42.5 mg/m^3) level was considered to be a NOAEL for histological changes in the nasal mucosa. (Different adjustments were made to this NOAEL by U. S. EPA to calculate the RfC of 1 μg/m^3 and by OEHHA to calculate the chronic REL of 10 μg/m^3 (8 ppb).)

Hydrogen sulfide (0, 10, 30, or 80 ppm) was administered via inhalation (6 h/d, 7 d/wk) to 10-week-old male CD rats (n = 12/group) for 10 weeks (Brenneman *et al*., 2000). Histological evaluation revealed that rats exposed to 30 or 80 ppm had significant increases in lesions of the olfactory mucosa but not other tissues. Multifocal, rostrocaudally-distributed olfactory neuron loss and basal cell hyperplasia were seen. The dorsal medial meatus and the dorsal and medial portions of the ethmoid recess were affected. The lowest dose (10 ppm) was considered a no observed adverse effect level for olfactory lesions.

Fischer F344 rats inhaled 0, 1, 10, or 100 ppm hydrogen sulfide for 8 hours/day for 5 weeks (Hulbert *et al*, 1989). No effects were noted on baseline measurements of airway resistance, dynamic compliance, tidal volume, minute volume, or heart rate. Two findings were noted more frequently in exposed rats: (1) proliferation of ciliated cells in the tracheal and bronchiolar epithelium, and (2) lymphocyte infiltration of the bronchial submucosa. Some exposed animals responded similarly to controls to aerosol methacholine challenge, whereas a subgroup of exposed rats were hyperreactive to concentrations as low as 1 ppm H_2S.

Male rats were exposed to 0, 10, 200, or 400 ppm H_2S for 4 hours (Lopez *et al.*, 1987). Samples of bronchoalveolar and nasal lavage fluid contained increased inflammatory cells, protein, and lactate dehydrogenase in rats treated with 400 ppm. Later Lopez and associates (1988) showed that exposure to 83 ppm (116 mg/m^3) for 4 hours resulted in mild perivascular edema.

D.2.2. Developing animals. Saillenfait *et al.* (1989) investigated the developmental toxicity of H_2S in rats. Rats were exposed 6 hours/day on days 6 through 20 of gestation to 100 ppm hydrogen sulfide. No maternal toxicity or developmental defects were observed.

Hayden *et al*. (1990) exposed gravid Sprague-Dawley rat dams continuously to 0, 20, 50, and 75 ppm H_2S from day 6 of gestation until day 21 postpartum. The animals demonstrated normal reproductive parameters until parturition, when delivery time was extended in a dose-dependent manner (with a maximum increase of 42% at 75 ppm). Pups exposed in utero and neonatally to day 21 postpartum developed with a subtle decrease in time of ear detachment and hair development, but with no other observed change in growth and development through day 21 postpartum.

Hannah and Roth (1991) analyzed the dendritic fields of developing Purkinje cells in rat cerebellum to determine the effects of chronic exposure to low concentrations of H_2S during perinatal development. Treatment of timed-pregnant female Sprague Dawley rats with 20 and 50 ppm H_2S for 7 hours per day from day 5 after mating until day 21 after birth produced severe alterations in the architecture and growth characteristics of the dendritic fields of the Purkinje cells. The architectural modifications included longer branches, an increase in the vertex path length, and variations in the number of branches in particular areas of the dendritic field. The treated cells also exhibited a nonsymmetrical growth pattern at a time when random terminal branching is normally occurring. Thus, developing neurons exposed to H_2S may be at risk of severe deficits. However, the lower level of 20 ppm for 7 hours is nearly 2 orders of magnitude above the present one-hour standard.

Dorman *et al*. (2000) examined the effect of perinatal exposure of H_2S on pregnancy outcomes, offspring development, and offspring behavior in rats. Male and female Sprague-

Dawley rats (12 rats/sex/concentration) were exposed to 0, 10, 30, or 80 ppm H_2S 6 h/day, 7 days/week for 2 weeks prior to breeding. Exposures continued during a 2-week mating period and then from Gestation Day (GD) 0 through GD 19. Exposure of rat dams and their pups (eight rats/litter after culling) resumed between postnatal day (PND) 5 and 18. Adult males were exposed for 70 consecutive days. Offspring were evaluated using motor activity (assessed on PND 13, 17, 21, and 60±2), passive avoidance (PND 22±1 and 62±3), functional observation battery (FOB) (PND 60±2), acoustic startle response (PND 21 and 62±3), and neuropathology (PND 23±2 and 61±2). No deaths occurred and no adverse physical signs were seen in F_0 males or females. There were no statistically significant effects on the reproductive performance of the F_0 rats as assessed by the number of females with live pups, litter size, average length of gestation, and the average number of implants per pregnant female. Exposure to H_2S did not affect pup growth, development, or performance on any behavioral test. The authors conclude that H_2S is neither a reproductive toxicant nor a behavioral developmental neurotoxicant in the rat at occupationally relevant exposure concentrations (i.e., at 10 ppm, the current occupational daily average exposure limits - TLV and PEL; however, the ACGIH is considering lowering the TLV to 5 ppm). The lowest level tested (10 ppm) is more than 300-fold higher than the CAAQS of 0.030 ppm.

E. Interactions between hydrogen sulfide and other pollutants

Ethanol can potentiate the effects of H_2S by shortening the mean time-to-unconsciousness in mice exposed to 800 ppm (1,120 mg/m³) H_2S (Beck *et al*., 1979).

Endogenous hydrogen sulfide may regulate smooth muscle tone in synergy with nitric oxide (Hosoki *et al*., 1997).

Hydrogen sulfide is often accompanied by other malodorous sulfur compounds, such as methyl mercaptan, dimethyl sulfide, and dimethyl disulfide. Some of these have odor thresholds lower than that of hydrogen sulfide. The complex mixture is often referred to as TRS (total reduced sulfur).

Lindvall (1977) reported that the perceived odor strength of H_2S is increased by the simultaneous presence of 600 ppb nitric oxide (600 ppb nitric acid is imperceptible by itself).

F. Conclusions

The current standard of 0.03 ppm (30 ppb) hydrogen sulfide for one hour based on odor is well below NOAEL levels from animal experiments where exposure lasted weeks to months, including the period of intrauterine development. However, it is greater than OEHHA's chronic Reference Exposure Level (REL) of 8 ppb, which is based on histological changes in the nasal area of mice. (The chronic REL is compared to the annual average H_2S concentration.) Ideally neither of these two benchmark levels should be exceeded by the properly averaged concentration.

Additional research might help reduce uncertainties regarding the impacts of hydrogen sulfide on the health of infants and children. This would include:

a. Odor testing of hydrogen sulfide in adolescents or younger children, if ethically permissible, to determine their odor threshold. Current data on odor detection in children are not consistent. Data on H_2S odor detection in children under controlled exposure are lacking.

b. The identification of children hypersensitive to the odor of hydrogen sulfide. While the odor from very low level H_2S would not itself threaten their physical health, the odor might be alarming to hypersensitive children. Psychosomatic complaints might be more confusing to children than to adults.

c. Physiologic testing of anosmic (either specifically anosmic to H_2S or totally anosmic) children at the CAAQS would be useful in determining whether if adverse physiological symptoms occur in the absence of odor detection.

d. Testing of the odor threshold for H_2S using the most current methodology among groups of healthy persons of both sexes in different age ranges. Data from such testing would likely be an improvement over the use of either the mean of 16 people (California Department of Public Health, 1969) or the mean from 26 studies, conducted over a period of 130 years, which found thresholds spanning a 20,000 fold range, from 0.07 ppb to 1400 ppb (Amoore, 1985). (If the highest and lowest values of the range in Amoore (1985) are dropped as outliers - Amoore (1985) stated that these two studies seemed to involve only one subject - the range would be 0.43 ppb to 190 ppb, a 440-fold range).

e. Further research is needed on the topic of when odor is an adverse health effect and how much consideration should be given to psychosomatic complaints accompanying odor annoyance (Dalton *et al*., 1997; ATS, 2000). A recent American Thoracic Society position paper titled "What Constitutes an Adverse Health Effect of Air Pollution?" (ATS, 2000) indicates that air pollution exposures, which interfere with the quality of life, can be considered adverse. This suggests that, for the purpose of setting a standard, odor-related annoyance should be considered adverse, even if nausea or headache or other symptoms are not present.

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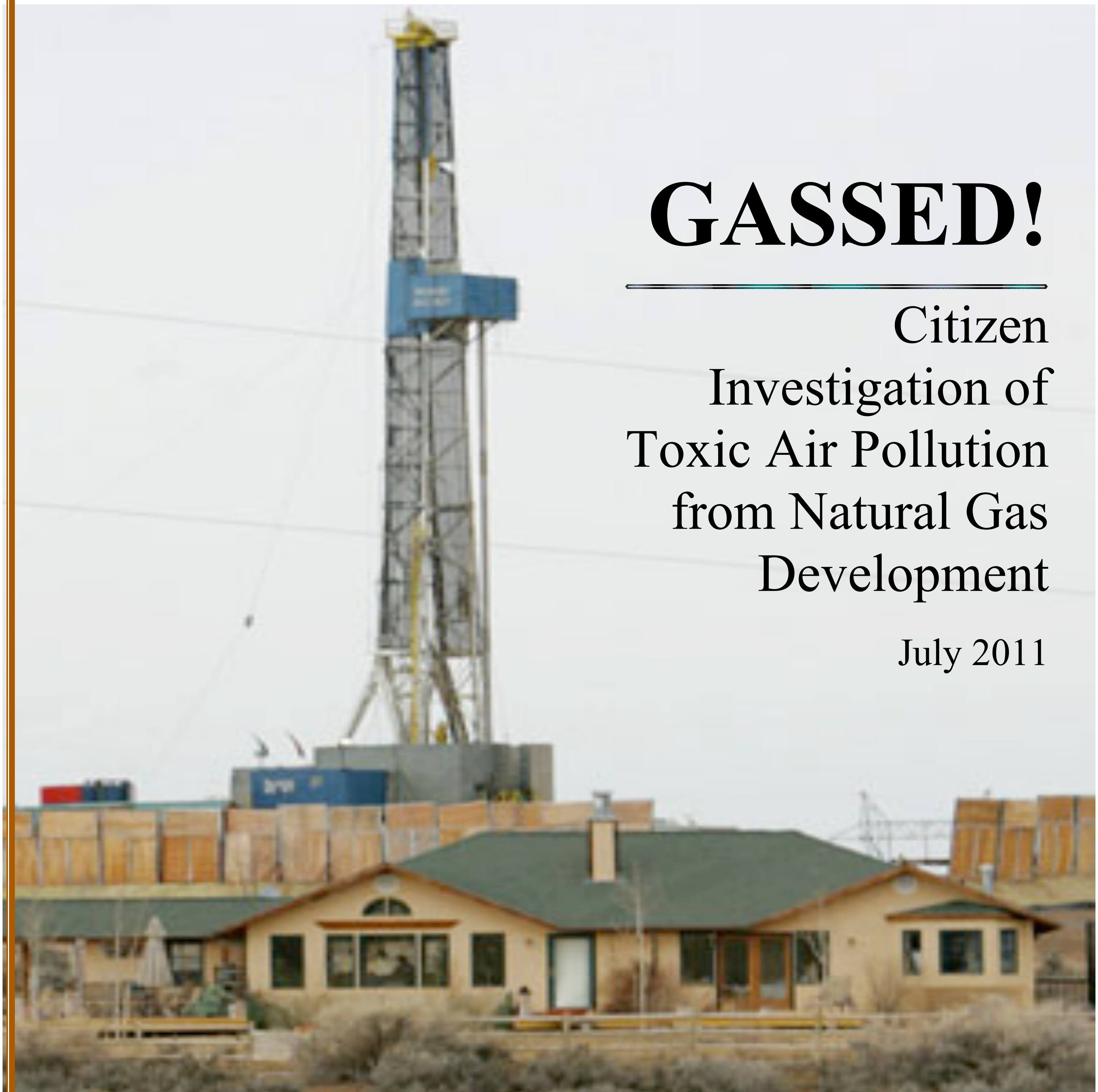

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Citizen Investigation of Toxic Air Pollution from Natural Gas Development

July 2011

10th ANNIVERSARY

Global Community Monitor

Breathing New Life into Communities

gcmonitor.org

Background on Global Community Monitor

Global Community Monitor, founded in 2001, trains and supports communities internationally in the use of environmental monitoring tools to understand and address industrial toxic pollution threats to their health and the environment.

GCM, best known as the innovator of the "Bucket Brigade", incubates community-based groups to develop the skills, expertise, and experience to win demands around environmental health and justice. Since GCM's approach is extremely replicable and effective, we have been invited to work with more than 40 communities in 27 countries. GCM collaborates with an established network of environmental health experts in the US and internationally to leverage resources for the communities.

Addition Information including News and Media available at:
http://gcmonitor.org/section.php?id=179
http://gcmonitor.org/section.php?id=29
http://gcmonitor.org/section.php?id=224

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Citizen Investigation of Toxic Air Pollution from Natural Gas Development

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Executive Summary

Over the past decade, oil and natural gas exploration and production have grown at an unprecedented rate in the United States. Since necessary environmental and health regulations are not in place for this industry, residents living near oil and natural gas sites may be exposed to highly toxic chemicals on a regular basis, with their health at risk.

During 2010-11, Global Community Monitor (GCM), responding to citizen odor and health complaints, launched a community-based pilot environmental monitoring program in northwest New Mexico, southwest Colorado and western Colorado to document and measure air pollution from natural gas facilities. Through the course of this pilot study, residents, armed with their own air monitors, documented a potent mix of chemicals in nine air samples from different locations. The sites in this program are all natural gas production and processing sites, although production of oil presents similar risks. Air sampling for this project targeted many aspects of natural gas development.

Through the course of this study, several serious issues emerged:

Citizen samples exposed alarming levels of toxins in the air.

A total of *22 toxic chemicals* were detected in the nine air samples, including *four known carcinogens,* toxins known to damage the nervous system, and respiratory irritants. The levels detected were in many cases significantly higher than what is considered safe by state and federal agencies. The levels of chemicals, including benzene and acrylonitrile, ranged from three to 3,000 times higher than levels established to estimate increased risk of serious health effects and cancer based on long-term exposure.

These air samples confirm the observations, experiences and first-hand complaints of residents. Odors and health effects that have been reported for years were consistent with exposure to the chemicals found in the samples. These results underscore the need of regulatory agencies to take such complaints seriously, given the close proximity between the industry and its residential neighbors.

At least two cancer-causing chemicals, acrylonitrile and methylene chloride, were detected at high levels near natural gas operations. Neither chemical is associated with natural gas or oil deposits, but both seem to be associated with the use of hydraulic fracturing (fracking) products. Resins acrylonitrile, 1, 3 butadiene and styrene (ABS) are suspected to be present in fracking additives.

Air emissions from natural gas production are largely unregulated and unmonitored, despite being a significant source of air pollution. State and Federal air monitoring devices are located several miles from production sites, and test for criteria air pollutants rather than specific volatile organic compounds associated with natural gas exploration and production.

Oil and gas exploration and production operations are exempt from two key provisions of the Clean Air Act's National Emissions Standards for Hazardous Air Pollutants, designed to protect public health. Because of these exemptions, the industry avoids complying with standards that are applied to other industries.

Based on the data gathered in this pilot study, highly toxic chemicals are permeating the air near homes, farms, schools, playgrounds, and town centers. Due to the lack of regulation and standards, key information about chemicals being used in the production process, including hydraulic fracturing is widely unavailable. Combined with the lack of appropriate air monitoring near production sites, **citizen right-to-know is virtually non-existent.**

Without registration of the chemicals by industry, neighbors of gas wells have no way of knowing what chemicals are stored on site, used during the industrial processes, vented to the air, water or land, or disposed nearby.

Recommendations

1. Given the proximity of residential and public property, any new sites –whether drilling, fracking, refining, or disposal – should be located at least one-quarter mile from homes, farms, schools, playgrounds, and businesses. This space would provide a **buffer zone** for industry to continue its operations while reducing community exposure to chemical contaminants.

2. The U.S. Environmental Protection Agency (EPA) should update air quality standards for oil and gas development, including the New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants, based on the principles of comprehensiveness, effectiveness, full health protection, forward looking, and enforceability.

3. Until strong new rules are in place, the oil and natural gas industry can and should **voluntarily invest in equipment that reduces pollution escaping to the air**. Such equipment is readily available and financially profitable for companies. These investments would increase efficiency and production and reduce cancer-causing chemicals from being emitted into the air in communities near production facilities – saving lives and protecting the health of neighboring families.

4. Current natural gas production and processing sites should **have air monitors near all operations and equipment. All data should be made available to the public**.

5. **EPA and state agencies must enforce the current laws** on the books vigorously and impose the maximum penalties available to create a culture that prioritizes public health. Regulators should be accessible and fully funded to ensure their ability to protect public health and the environment.

As the natural gas industry continues to grow, so will the number of families neighboring and affected by the emissions. Industry and government leaders have a unique opportunity to address public health and environmental issues by implementing all of these recommendations. For coexistence between communities and industry to be possible, chemical exposure has to be immediately addressed.

Oil and Natural Gas Development and Air Pollution

There are a variety of chemicals used and released during the drilling, fracking, and production phases of oil and gas development. In addition, different types of wastes are produced throughout the development process. Air pollution is generated at all stages of oil and gas development including wellpad construction and drilling, workovers, fracking and completion, gas compression, evaporation of chemicals from produced water and frack flowback, dehydration, separation, waste treatment and disposal, transmission and processing.

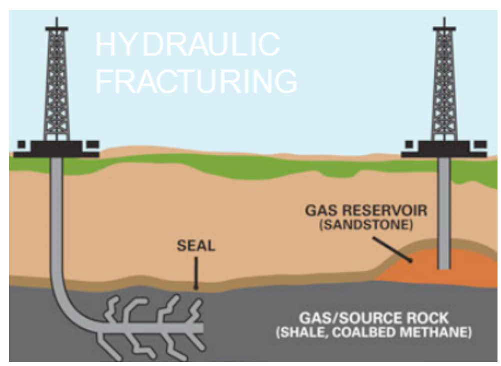
The following is a brief glossary of the life cycle of natural gas development:

Construction activity
Even prior to producing natural gas, air pollution is generated by heavy construction activity including trucks and other equipment that emit air pollutants at well pads, pipelines, roads and compressor stations.

Drilling
During the drilling of a well, air pollution is generated by diesel engines powering the drill rig, as well as by any natural gas emissions being vented from the hole in the ground. These emissions could include various toxic gases, including volatile organic compounds.

Hydraulic fracturing (fracking) and completion[1]

Image from Stark Political Report



While oil and gas have always been extractable from the natural fissures in certain rock formations, some of these deposits are too diffuse to be economically feasible to exploit using traditional drilling methods. Increasing demand, however, has spurred the evolving development of fracturing technology. Pioneered in west Texas, fracking is being used to increase the productivity of drill sites in shale, coalbed methane, and tight sands formations that previously were too expensive to drill.

Fracking is dependent on fracturing fluid, typically comprised of water-based concoctions riddled with assortments of chemicals and proppants like sand. The chemical makeup of the fluid varies from company to company and site to site. The process of fracking involves perforating oil and gas wells and then pumping chemical fluid into the earth. By pumping fracturing fluid deep into the rock formation fissures under the earth at very high pressure, the cracks are expanded and then propped open with the proppant. These expanded cracks allow a single well to tap into multiple diffuse deposits.

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[1] "Hydraulic Fracturing Research Study," US EPA. Office of Research and Development. 24 May 2011. http://www.epa.gov/safewater/uic/pdfs/hfresearchstudyfs.pdf

Though fracking enables cost effective production of natural gas for the gas companies, it also comes with risks to public health and the environment. One of the least documented risks has been from air pollution caused by fracking compounds during their use, storage, or waste disposal.

Pits
Waste from drilling, fracking, or production may be dumped into open air pits to allow some of the toxic material to evaporate into the air. This can result in significant air pollution.

Land application (including land farming)
Waste from drilling, fracking, or production may be spread on the ground or otherwise applied to the land. This can result in significant air pollution.

Compressor station
Gas from wells is collected at central locations and compressed into smaller volumes at stations. Another type of compressor is located on the well site. Both types of compressors can leak and release a variety of toxic gases.

Condensate tanks
Some well sites produce semi-liquid gases along with natural gas that are stored in tanks, which can leak various toxic gases into the air.

Dehydrators
These systems are needed to remove water from natural gas and can release toxic gases in the process.

Flaring
Unwanted gases in the production process may be burned off in the open air through flares, which can produce other toxic gases as a result.

Fugitive emissions
Leaks in equipment such as pumps, valves, compressors, pipes and tanks can result in significant air pollution releases because of the number of components in gas processing.

Venting
During various stages of gas exploration, production and maintenance, gases are vented directly into the air rather than contained or flared. Venting can release large volumes of toxic gases.

Gas processing plant
The last stage of gas production involves the refining of the raw gas into the final product. This occurs at large gas processing plants, which have many sources of air emissions.

Additional waste disposal sites[2]

Wastes from various stages of gas production and processing may be sent to treatment sources including landfills, injection sites and wastewater treatment sites, which can also release air pollution.

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[2] "Public Health and Toxics." EARTHWORKS. 20 March 2011, http://www.earthworksaction.org/Health%20and%20Toxics.cfm

Air Pollution and Human Health Impacts of Natural Gas Development

Air pollution can affect our health in many ways, with both *short-term* and *long-term* effects. Different groups of individuals are affected by air pollution in different ways. Some individuals are much more sensitive to pollutants than others. Sensitive populations, including young children and elderly people, often suffer more from the effects of air pollution. People with health problems such as asthma, heart and lung disease may also suffer more when the air is polluted. The extent to which an individual is harmed by air pollution usually depends on the **total exposure** to the damaging chemicals, i.e., the *duration of exposure* and the *concentration of the chemicals.* Total exposure must be taken into account when assessing air pollution risks.

Examples of **short-term effects** include irritation to the eyes, nose, and throat, and upper respiratory infections such as bronchitis and pneumonia. Other symptoms can include headaches, nausea, and allergic reactions. Short-term air pollution can aggravate the medical conditions of individuals with asthma and emphysema.

Long-term health effects can include chronic respiratory disease, lung cancer, heart disease, and even damage to the brain, nerves, liver, or kidneys. Continual exposure to air pollution affects the lungs of growing children and may aggravate or complicate medical conditions in the elderly.[3]

Chemicals such as benzene, toluene, ethylbenzene and xylene (BTEX) are known to be present around natural gas development sites, both from the gas deposits as well as chemical additives. Our independent testing found significantly high amounts of these toxic gases downwind of various sites. Health effects from BTEX include dizziness and confusion, eye, nose and throat irritation, birth defects, kidney, liver, and neurological damage, and cancer. For example, benzene is known to cause leukemia.[4]

Hydrogen sulfide was also found in the Bucket tests, warning signs for the gas are often visible near well pads. Long-term exposure to hydrogen sulfide is associated with an elevated incidence of respiratory infections, irritation of the eye, nose and throat, coughing, breathlessness, nausea, headache, and mental health impacts, including depression.[5] It is recommended, that workers handling hydrogen sulfide be equipped with hydrogen sulfide monitors, respirators, and rescue packs for protection in the event of elevated exposure; the public has no such protection.[6]

Additional toxic substances were detected at high levels in the air samples, including toxic gases not previously associated with natural gas development, suggesting that substances possibly associated with fracking additives may have been released into the air.

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[3] "How Can Air Pollution Hurt My Health." Health Effects of Air Pollution, Lawrence Berkeley National Laboratory, March 2011, http://www.lbl.gov/Education/ELSI/Frames/pollution-health-effects-f.html
[4] NRDC, Drilling Down, October, 2007, table on page vi
[5] Chernaik, Mark. Data Interpretation Synthesis Letter. Science for Citizens. 16 Feb. 2011
[6] Air Products, Material Data Sheet, http://avogadro.chem.iastate.edu/MSDS/hydrogen_sulfide.pdf

Overall, air samples gathered for this project showed that neighbors of the natural gas operations in the target communities are breathing multiple chemicals that can cause an increased risk of cancer and other serious health effects. There are no health-based standards for exposure to multiple chemicals, although the negative health impacts are considered to be increased.

Natural Gas Development in Colorado and New Mexico

Growth in Project Areas

GCM worked with two communities in the San Juan Basin—one in southwest Colorado and a second in northwest New Mexico. In addition, GCM worked with a third community in Garfield County in western Colorado.

- ***Colorado's natural gas production has risen 450% since 1990 with over 27,000 active wells statewide.*** [7]

- ***Currently there are approximately 3,400 wells in La Plata County, CO.*** [8]

Image from BP.com

- ***There are approximately 21,000 wells in San Juan County, NM***

- ***The approximate total of wells in the entire San Juan Basin is 35,000 wells*** [9]

Image from Realtor.com

- ***In western Colorado, Garfield County has an estimated 8,249 active wells with 2,037 new permits approved in 2010*** [10]

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[7] "Background." Western Colorado Congress, 20 March 2011, http://www.wccongress.org/gvca.htm#background

[8] "Natural Resources- Oil and Gas." La Plata County Planning Department, 25 March 2011, http://www.co.laplata.co.us/departments_and_elected_officials/planning/natural_resources_oil_gas

[9] United States Department of Interior, Bureau of Land Management, **Farmington Resource Management Plan** (December 2003) Final **RMP**/Record of Decision

[10] May 2011 Colorado Oil & Gas Conservation Commission Staff Report

Target Communities

GCM worked with communities in northwest New Mexico and southwest Colorado in partnership with the San Juan Citizens Alliance. The project also included communities in western Colorado in partnership with the Western Colorado Congress. The communities were trained in air monitoring and bucket sampling around natural gas development sites.

Northwest New Mexico: Aztec and Farmington Area

Of the three communities involved in this pilot project, northwest New Mexico has the longest history of complaints about natural gas drilling. Natural gas has been drilled for, and produced, in northwest New Mexico for over 60 years with natural gas facilities interspersed among residential areas. Community residents in northwest New Mexico have noticed strong odors since the late 1980s, reported as smelling like rotten eggs, petroleum and sewage, around the ever-expanding oil and gas industry. Residents have experienced nose, throat and eye irritation that occasionally would last for hours after smelling the odors. When the odors increased in frequency, so did the associated acute health effects.

Energy companies in the area, including BP, Energen, XTO, Devon, Conoco Phillips, Enterprise, Williams and Questar, are associated with drilling for and transporting natural gas, where operations at sites can include fracking by numerous companies. San Juan County in Northwest New Mexico consists of more than 100,000 residents potentially affected by natural gas production, either by living near a gas well or near the plants that process the natural gas.

There are many gas wells near schools, churches, private residences and community centers. Natural gas odor incidents are frequent, along with adverse health effects in the community. For example, in December 2009, one of the members of the San Juan Citizens Alliance and long-term area resident Shirley McNall went out to get her mail. She was immediately struck with an extremely potent rotten egg odor and overcome with dizziness and nausea. According to McNall, she fell to the ground and was forced to crawl back into the house. While the symptoms began to slowly subside, she reported numbness in her lips that lasted for three days after the incident.

During less severe odor incidents, residents commonly reported headaches, nausea and dizziness in addition to nose, throat and eye irritation.

Shirley McNall- Aztec, NM

The health effects and reported odors could be associated with chemical exposure. McNall and other residents have documented odors most frequently during the late evening through the early morning hours. This could be related to the industrial process and/or weather patterns that concentrate or bring the toxic fumes near homes.

Community members call the New Mexico Oil and Gas Conservation Division frequently, often multiple times a week, to report these odors. However, no satisfactory permanent solutions have been reached. On occasion, a representative of the New Mexico Oil and Gas Conservation Division will conduct an on-site investigation. During one of these investigations, the representative informed the residents that the most likely cause of the odors is “treated” hydrogen sulfide. This is a major concern because hydrogen sulfide is highly toxic and, while its presence requires formal signage by law, no signage was present at the well under investigation.

Homeowners are not generally informed of the toxic risk when their property is in proximity to natural gas facilities. Split estate situations where mineral ownership is separate from private surface ownership creates confusion and uncertainty surrounding where wells can be drilled in relation to homes. Numerous contractors and subcontractors may be involved with natural gas facilities, further complicating responsibilities and actions. The New Mexico Environmental Department and the U.S. Environmental Protection Agency’s (EPA) efforts to monitor and evaluate air impacts from natural gas resources in northwest New Mexico have been limited.

Southwest Colorado: Durango

This troubling trend is not unique to the northwest corner of New Mexico. The expanding oil and gas industry has spread into communities in Colorado.

La Plata County, located in southwest Colorado where the southern Rockies meet the high desert country of northern New Mexico, is home to three municipalities, four river drainages, and a sovereign Indian nation. It is known for its outdoor activities including hiking, rock climbing, backpacking and white water rafting along the Animas River, and for the incredibly lucrative coalbed methane field that underlies it.

Coalbed methane development has been going on here since in the mid-1980s. The environmental degradation associated with development has been documented to include coal seam fires and hydrogen sulfide and methane seeps at the Fruitland formation outcrop. The full impacts of development on air quality and public health, however, remain largely unexamined.

Due to split estate status, energy companies can lease the mineral rights underneath the property of a homeowner. Insufficient setbacks and surface owner protections allow the oil and gas industry to place facilities directly next to homes and schools. Near Sunnyside Elementary School, air monitoring on January 7, 2011 showed elevated levels of four known carcinogens. Two of the carcinogens were recorded at levels that are considered to be an unacceptable long-term exposure risk.

Josh Joswick- Durango, CO

LaPlata County has an estimated 3,400 wells. Many county residents therefore live in or adjacent to the ‘gas patch,’ often times in close proximity to gas wells, compressor stations, dehydrators, and processing plants. This incompatible mix of industrial activity in rural residential areas has had an impact on people's lives. Gas patch residents in La Plata County report odors similar to their neighbors in New Mexico. These odors, smelling like burning oil, car exhaust, and burning rubber, are most frequently noticed around well sites.

Aaron Mallet, a La Plata County resident active with the Bucket Brigade, stated on September 28, 2010: "On a regular basis there is an acrid smell in the air that emanates from that well pad."[11] Residents have also documented headaches, sore throats and burning nasal passages during these odor incidents.

Western Colorado: Battlement and Silt Mesas

Lastly, GCM worked with the communities of Battlement and Silt Mesas in Garfield County, Colorado. Battlement and Silt Mesas are two rural communities experiencing impacts from nearby development of natural gas.

Battlement Mesa is an unincorporated retirement community of 5,500 residents in western Garfield County. Originally constructed by Exxon in the 1970s for workers in the oil shale industry,[12] it was later marketed as a destination for retirees seeking a peaceful place to spend their golden years. Exxon eventually sold the surface properties but retained the mineral rights to extract the fossil fuels beneath Battlement Mesa at any time in the future.

Community members watched as natural gas wells incrementally came closer to Battlement Mesa, and the residents began to wonder if drilling would be allowed within their retirement neighborhood.

Dave Devanney- Battlement Mesa, CO

In 2009, Battlement Mesa learned of a proposal to drill 200 natural gas wells within its borders, including sites near homes, along the Colorado River, on the golf course, and near a school. Battlement Mesa residents called for thorough scientific research of the potential public health impacts of natural gas development before any permitting decision. After hundreds of residents signed a petition, a groundbreaking Health Impact Assessment was commissioned for drilling within Battlement Mesa and county officials delayed any new drilling inside of the retirement community until this process was completed. Drilling, however, began just outside the border of the community and community members began complaining of noxious fumes being emitted.

Battlement Mesa residents documented strong petroleum-like odors in the middle of the night and early mornings. Residents believed that these strong petroleum, diesel and chemical smells were caused by nearby fracking operations. Nearby residents began experiencing health effects such as throat and nose irritation, headaches, itching skin, burning eyes, and dizziness. Residents

[11] Mallet, Aaron. Pollution Log 28 Sept. 2011
[12] Oil Shale is a different formation than the source of shale gas.

called the Colorado Oil and Gas Conservation Commission to formally report the odor events; they started documenting odor occurrences, and they contacted local authorities.

The Colorado Oil and Gas Conservation Commission cited the operator for failing to capture nuisance odors derived from its operations. The company was encouraged to use additional vapor recovery techniques during flowback operations to reduce odors (but never received a monetary penalty). Residents noticed a marked diminishment of the odors, but around the same time, in November of 2010, a local news channel highlighted nearby Silt Mesa residents' problems with natural gas development. Silt Mesa residents reported odors they thought were caused by natural gas activity, and Dave Devanney of the Battlement Concerned Citizens contacted them.

Silt Mesa is a network of irrigation canals and small ranches, sitting along the Colorado River between Rifle and Silt, Colorado. Drilling for natural gas is taking place near homes and water supplies, presenting many of the same challenges as on Battlement Mesa.

One Silt Mesa family with two young sons had three natural gas drill rigs surrounding its property, each with ongoing flaring. The nearest flare stack was less than one-half a mile from their home. Family members reported pungent odors of rotten eggs followed by severe headaches, nosebleeds and rashes. The nosebleeds were persistent and heavy, much different than the average nose bleed. The mother described it as "almost like hemorrhaging." The youngest son developed a full body rash, which prompted a doctor visit. Upon examination, the doctor immediately told the Silt Mesa family to evacuate their home.

Although the family was forced to vacate their home because of nearby industrial activity, the state did not issue any violations. According to Colorado rules, Silt Mesa is not a High Density area, therefore, drilling for natural gas in the area does not warrant additional safety precautions.[13]

Today, the Silt Mesa family has left their home and put it up for sale. An air sample taken on January 15, 2011, on their property, contained levels of hydrogen sulfide more than 185 times above the long term level set by the U.S. EPA (2 $\mu g/m^3$) to estimate increased risk of serious health effects.

This Silt Mesa family, as well as the Battlement Mesa residents, call frequently to report odor complaints and other incidents of non-compliance. They call the Colorado Oil and Gas Conservation Commission, the Garfield County Oil and Gas Department, the Colorado Department of Public Health and Environment, and occasionally, the Environmental Protection Agency. The communities have seen worse local air quality since natural gas development markedly increased in Garfield County, although limited air monitoring is conducted by local and state authorities.

Collectively, nine air samples were taken by the Bucket Brigades. The members of San Juan Citizens Alliance and Battlement Concerned Citizens have taken the results to local officials and

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[13] Colorado Oil and Gas Conservation Commission. "Series Safety Regulations" 2 June 2011. http://cogcc.state.co.us/

the U.S. EPA, but, to date, the agencies have not taken any action. Most of the residents feel their concerns have fallen on deaf ears.

A press release was issued in Aztec, New Mexico and Durango, Colorado announcing the air sample results. The residents still have not received an adequate response from the regulatory agencies. On Monday, April 4, 2011, Katee McClure sent an e-mail to the New Mexico Environment Department inquiring about who is responsible for enforcing air regulations. Although, the agency did respond in a timely manner, it provided incorrect information regarding standards for hydrogen sulfide pollution while failing to take responsibility or provide information for the responsible agency.[14]

[14] McClure, Katee. 4 April 2011

Citizen Air Sampling: Bucket Brigade Projects

Community-Based Air Monitoring: A Crucial Piece of the Puzzle

Building a trail of evidence

Regulatory and environmental agency personnel are not available at all hours to come out during a pollution incident. In the case of Colorado and New Mexico, a proper citizen complaint system is not established. A proper citizen complaint system would include a telephone hotline followed by rapid response from regulatory agencies and timely air sampling during odor incidents. Community-based monitoring provides an opportunity for residents to respond immediately to the pollution incident with sampling equipment and to contact agency personnel.

GCM trained members of the Western Colorado Congress, the San Juan Citizens Alliance, and other community members to keep a record of pollution incidents. These records include: the location, nature, and duration of the incident; the wind direction, health effects or property damage; and how the incident was addressed – by a call to the regulatory agency or the company suspected or known to be the source of the pollution, or informative calls to other neighbors.

Pollution incident records are referred to as “pollution logs.” Pollution logs filled out by community members ensure that a record is maintained beyond regular agency business hours. Community members are also encouraged to take pictures and/or use a video camcorder to catch a visual image of the pollution.

Bucket Brigades provide evidence and hard science to support the anecdotal stories of health impacts that all affected communities know too well: strange odors causing nausea, stinging eyes, burning noses, sore throats, coughs, and other distressing health symptoms. Community-based monitoring engages community members in record maintenance, site identification, operation of monitoring equipment, documentation, and custody and shipping of the sample.

The information gathered by Bucket Brigades, combining science with community experience and reports, helps bridge the gap between communities, regulators and industry. Air sampling and monitoring can provide key evidence exposing chemical exposure, can be a tangible way to show that the air pollution has decreased in a community, and can help build relationships where community members coexist with their industrial neighbors.

Bucket Brigade Training & Methods

To begin a project, GCM conducts a research assessment of toxic hazards in a target community and identifies the appropriate environmental monitoring tools that will assist community members in investigating their health concerns and exposures. We review the data on pollution sources and toxins and prioritize the most serious for early action. Due to the lack of publicly available data regarding the air emissions from natural gas drilling and refining sites, we had little research available for reference in this project.

All Bucket Brigade trainings are conducted on site, in the local community. For this project, GCM was given a local tour by community members in areas near Durango, Colorado; Battlement/Silt Mesas, Colorado; and Aztec, New Mexico in late July, 2010. During the training, GCM provided a day-long classroom training, including background on pollution and environmental health, how to document pollution incidents, hands on training and how to use monitoring equipment. We worked with the local community members to co-design an environmental sampling plan.

The training and plans emphasize standard scientific methods. Community members learn how the monitoring equipment works, the best time to use it, and the appropriate paperwork to fill out before shipping a sample to the lab. The Bucket Brigade's work is strengthened by following stringent Quality Assurance/Quality Control (QA/QC) protocols and the use of EPA approved labs.

The Bucket Monitoring Equipment

Due to the nature of the uncertainty of the emissions associated with natural gas drilling, hydraulic fracturing and refining, this project chose to use the Bucket as the monitoring equipment. The Bucket is modeled after the Summa Canister,[15] but has some advantages in its use.

The Bucket is portable, requiring only a tedlar bag and vacuum to take the grab sample. Air is "grabbed" out of the air for two to three minutes and captured in the bag. Once the sample is taken, the tedlar bag is sealed, removed from the bucket and sent to the lab for analysis.

The air sampling Bucket, gcmonitor.org

[15] State of Nevada, Division of Environmental Protection. "Summa Canister Sampling". http://ndep.nv.gov/fallon/summa.pdf

The lab analysis is conducted by Columbia Analytical Services in Simi Valley, California. The lab utilizes EPA method TO-15 and ASTM D 5504-08 method for sample analysis. The TO-15 analysis includes a spectrum of more than 70 volatile organic compounds and the ASTM D 5504-08 method is used to test for 20 sulfur compounds.

Once the community members are trained on the equipment, the buckets are kept at various locations in the community – selected based on the location of odors and health symptoms that have been experienced and reported. When an odor incident occurs, Bucket Brigade members join together to bring a bucket to the site of the odor incident and take a sample of the air at the time of the odor.

Results & Discussion of Results

Individual sample results and overall trends:

For this project, communities in New Mexico and Colorado took a total of nine air samples between September 2010 and January 2011. This report documents serious toxic air pollution generated at various points of the life cycle of natural gas development. Targeted sampling sites included well pad, compressor station, gas separation plant, dehydrator and waste disposal site. Serious cancer-causing chemicals were detected at elevated levels, including chemicals associated with the fracking process used increasingly by energy companies.

While bucket samples are short-term grab samples of the air breathed by community members living near natural gas development facilities, letters and pollution logs reveal that the odors are persistent and occur on an ongoing basis. We therefore consider the data to be indicative of long-term exposures, and the expert interpretation used in this report compares the data to pollutant levels linked to long-term health effects.

A total of 22 toxic chemicals were detected in the nine air samples, including four known carcinogens, toxins known to damage the nervous system, and respiratory irritants. The levels of chemicals detected were in many cases significantly higher than is considered safe by state and federal agencies. The levels were between three to 3,000 times higher than levels established by public health agencies to estimate increased risk of serious health effects and cancer based on long-term exposure.[16]

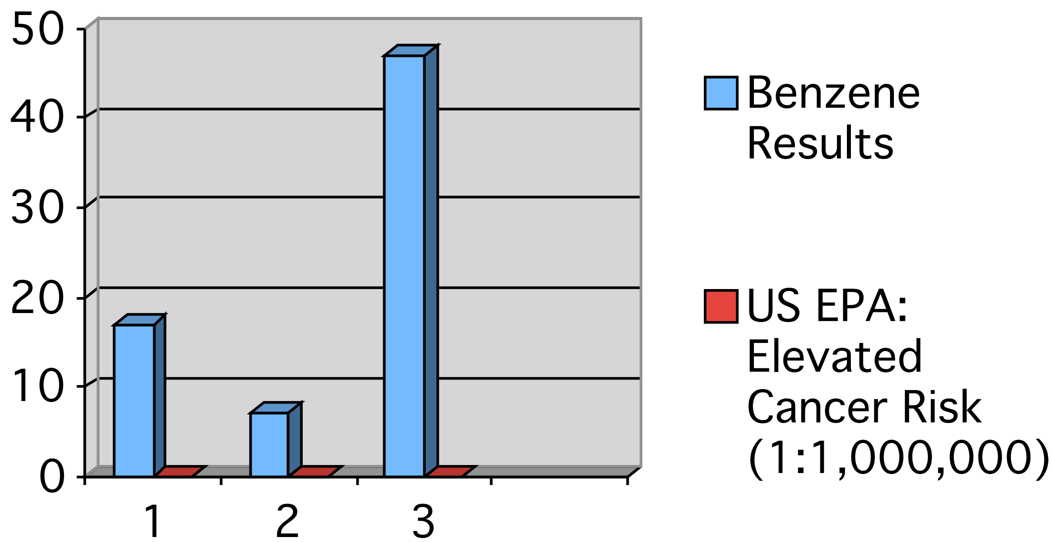
The most significant results:

- ***Benzene***, a known carcinogen, was found at high concentrations in four air samples at levels between 6.3 and 47 $\mu g/m^3$. These levels are 48.5 to 800 times higher than the level set by the US EPA of 0.13 $\mu g/m^3$ to estimate increased cancer risk from long-term exposure.[17]

  Benzene can also cause serious non-cancer health effects which can damage the blood and nervous system Levels of benzene in one of the nine samples, collected on January 7, 2011 near the Sunnyside Elementary School, Durango, Colorado, exceeded the level set by the U.S. EPA for benzene (30 $\mu g/m^3$) to estimate increased risk of non-cancer health effects.

[16] This report defines an elevated cancer risk as 1:1,000,000
[17] http://www.epa.gov/ttn/atw/toxsource/table1.pdf

Sample 1: 200 Montana St Bloomfield NM
Sample 2: Bondad 33-10 #26 Williams Well, Durango, CO
Sample 3: Intersection of US 550 & CR 218 Durango, CO, near Sunnyside Elementary



- ***Acrylonitrile***, a human carcinogen, was found in five samples at levels between 7.9 and 30 μg/m^3. These levels are 790 to 3000 times above the U.S. EPA level of 0.01 μg/m^3, set to estimate an increased risk of cancer from long term exposure. All of these levels correspond to what EPA would consider an "unacceptable cancer risk" in that long-term exposure is associated with a cancer risk of greater than 100 in a million.[18]

  Acrylonitrile is also a respiratory irritant, causing degeneration and inflammation of nasal epithelium. Levels of acrylonitrile in the five samples exceeded the level set by U.S. EPA for risk of increased non-cancer health effects from long term exposure (2 μg/m^3) by 3 to 15 times.[19]

- ***Methylene chloride***, a human carcinogen, was found in five samples at levels between 7.9 and 17 μg/m^3. These levels are 3 to 8 times higher than the level set by the U.S. EPA (2.0 μg/m^3.) to estimate an increased risk of cancer from long-term exposure.

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[18] Communication from Miriam Rotkin-Ellman, Natural Resources Defense Council. 7 June 2011
[19] The USEPA Reference Concentration (RfC) is an estimate of a continuous inhalation exposure concentration to people (including sensitive subgroups) that is likely to be without risk of deleterious effects during a lifetime.

- ***Ethylbenzene***, a human carcinogen, was found in five samples at levels between 5.1 to 22 $\mu g/m^3$. These levels are 12 to 55 times higher than the level set by the US EPA ($0.4 \mu g/m^3$) to estimate increased cancer risk cancer from long-term exposure.

- ***Xylene***, were found at a level of 100 and 154 $\mu g/m^3$. These levels exceed the U.S. EPA's level for estimating increased non-cancer health risks of 100 $\mu g/m^3$.

- ***Hydrogen sulfide*** was found in one sample at 370 $\mu g/m^3$ which is more than 185 times above the long term level set by the U.S. EPA (2 $\mu g/m^3$) to estimate increased risk of serious health effects.

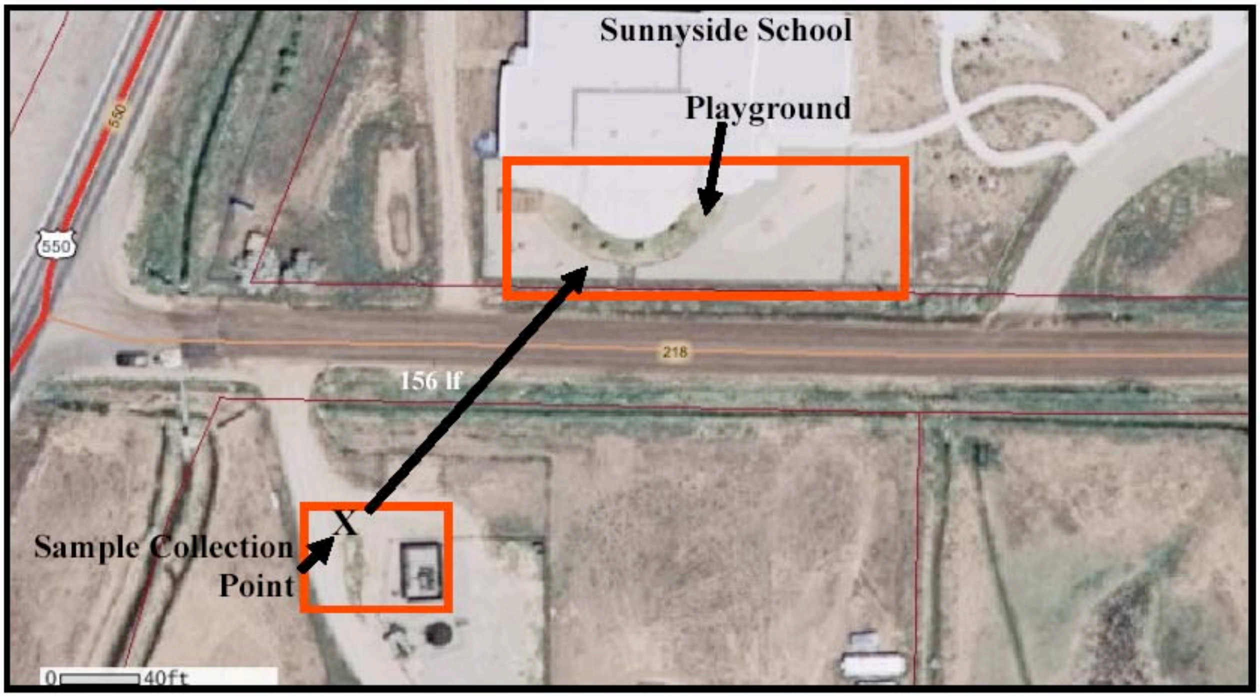
  Long-term exposure to hydrogen sulfide is associated with an elevated incidence of respiratory infections, irritation of the eye and nose, cough, breathlessness, nausea, headache, and mental symptoms, including depression. The World Health Organization's Guideline Value for exposure to hydrogen sulfide is 7 $\mu g/m^3$ over a 30-minute period.

For the first time, at least two cancer-causing chemicals found at high levels, acrylonitrile and methylene chloride,[20] were detected by the air samples at a variety of natural gas development sites. Neither is associated with natural gas and oil deposits, but both have been shown to be associated with chemicals used in the fracking process to increase yields from oil and gas deposits.

The air samples found high levels of chemicals that can cause symptoms that match the odors and health effects reported by nearby residents for years. This confirms the need for agencies to take such complaints seriously and to better monitor and require pollution controls at all points of natural gas production and processing.

[20] Cherniak, Mark. Data Interpretation Synthesis Letter. 16 Feb 2011

Image from San Juan Basin Health Department



Bucket Brigade Sample Collection Event
January 7, 2011
Dehydrator Facility Located
156 lf from Sunnyside Kindergarten Playground

Results near the Sunnyside School in La Plata County, Colorado

On January 7, 2011, two members of the Bucket Brigade team in La Plata County, Colorado, took an air sample less than 50 feet from a dehydrator that is less than 200 feet from the Sunnyside Elementary School playground near Durango. This natural gas dehydrator is a frequently suspected source of unknown chemical odors. The sampling team on site experienced odors. Subsequent analysis of the air sample revealed a number of toxic chemicals, including four known carcinogens.

A significant level of acrylonitrile, a human carcinogen, was detected in this sample (as it was in four other samples in this report) at a level above which is considered by the US EPA to be an unacceptable long-term exposure risk.[21] Methylene chloride, a human carcinogen, was also detected in this sample (as it was in four other samples) at a level above which is considered to be an unacceptable long-term exposure risk.

Two more carcinogenic substances, benzene and ethylbenzene, were also detected in this sample at levels above that which is considered to be an unacceptable long-term exposure risk. The

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[21] http://www.epa.gov/ttn/atw/toxsource/table1.pdf

level of benzene in this sample, 47 ug/m^3, is notable in that it is the highest level of benzene detected so far in this area by the Bucket Brigade. Besides acting as a carcinogen, benzene can also adversely impact the human immune system by decreasing circulating levels of lymphocytes. To prevent reduced lymphocyte counts, the U.S. EPA has an established a reference (long-term) concentration for benzene of only 30 ug/m^3.

Mark Chernaik, PhD, interpreted the test results for this project. According to Dr. Chernaik, "The level of benzene in this sample is more than 50% above the U.S. Reference concentration for benzene. If this detected level of benzene in this sample represents ambient air quality that generally prevails at this location, then persons living or attending school at this location would be at risk to adverse impacts to the immune system."[22]

The levels of other aromatics in the sample, – 4-ethyltoluene, 1,3,5-trimethylbenzene, 1,2,4-trimethylbenzene, – although not above health reference levels are strikingly similar to the levels of these aromatics in four other samples and seem to be a fingerprint for volatile organic compounds near an oil and gas facility in this area. The high levels of the tentatively identified compounds propane and butane also strongly suggest that the source of the volatile organic compounds is related to gas field activities.

Matching odors and health effects to sample results

Residents of natural gas production facilities involved in the Bucket Brigade air-testing project recorded their observations and health effects during testing. Once sample results were available, the observed odors and health effects noted in pollution logs were compared to the known health effects of the toxic chemicals found in the samples. Here are several examples:

> *"On Wednesday, Jan 19th air sample was taken at the Blanco, NM Enterprise Buena Vista Compressor Station in Pump Canyon north of several homes. Chris Velasquez and his family live "down wind" of this site. Chris was my guide and companion on the testing trip.*
>
> *I smelled the heavy smell of oily burning plastic. My eyes burned and my nose, throat and mouth became irritated instantly. The soft tissue in my nose, throat and mouth are still sore today as I write this. I have been coughing and my nose is still runny. My eyes are still very red and irritated."*[23]

The sample results confirmed the presence of several noxious benzene compounds, including chlorobenzene, 1, 2, 4-trimethylbenzene and xylene compounds. They are significant irritants to the respiratory system and combined exposure to these could have resulted in the health effects experienced by the sampler.

> *"Warren & I noted additional sharp natural gas/petroleum odors coming from the direction of the BP/CP wells when we did the air sample on January 18th. Warren noted that his eyes were burning. My throat was very irritated and my eyes burned. The musty*

[22] Chernaik, Mark. 25 Jan. 2011
[23] McNall, Shirley. 20 Jan. 2011

sewage/feed lot odor is nauseating and causes throat irritation and burning eyes for me.

The wells are on BLM land that was granted to the City of Aztec in 1963 for Recreation & Public Use Purposes (R&PP). Some of that land has been granted to Aztec Schools for the new athletic fields and sports complex located about 800 ft. from the wells."[24]

Sample results from the January 18th sample confirmed the presence of 22 different toxic gases, including cancer-causing benzene. Many of the gases present in the sample irritate the respiratory system and the eyes. Again, the observations recorded by Bucket Brigade air samplers match the sample results.

[24] McNall, Shirley. 20 Jan. 2011

Recommendations

Given the close proximity of residential and public property, any new sites – whether drilling, fracking, refining, or disposal – should be located at least one-quarter mile from homes, farms, schools, playgrounds, and businesses. This space would provide a **buffer zone** for industry to continue its operations while reducing community exposure to chemical contaminants.

U.S. EPA should update air quality standards for oil and gas development, including the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP), based on the following principles:

Comprehensiveness: All sources of air pollution in the oil and gas sector, including exploration, production, processing, transmission, distribution, and storage, and all pollutants released by these sources should be included in any updated air quality regulations, regardless of the level of emissions or major or area source status.

Air monitoring and transparency: Natural gas development sites including well pads, compressors, gas plants, and waste sites should be required to continuously monitor for volatile organic compounds and hydrogen sulfide in order to ensure compliance with regulations, emission limits and public health protections. All data should be publicly available via the web to provide full transparency to the public.

Effectiveness: The EPA should require the best available control technology and require practices and technologies that both reduce air pollution and promote more efficient oil and gas operations.

Full Health Protection: The EPA should consider prohibiting hazardous air pollutant emissions in certain circumstances, and ensure that any residual risk standards reduce lifetime cancer risk from oil and gas operations to below one in one million.

Forward Looking: EPA should develop mechanisms to ensure that any new equipment, facilities, technologies or practices will be subject to air pollution control requirements that may be required under any updated NSPS and NESHAP.

Enforceability: Any standards should be practicably enforceable by including monitoring, record keeping, and reporting requirements necessary to ensure continuous compliance with the standards and to allow the public, States, and the EPA to easily determine deviations and enforce any noncompliance.

CONGRESS should close the gaping loophole in the Clean Air Act's National Emission Standards for Hazardous Air Pollutants (NESHAPs). Oil and gas exploration and production operations are exempt from two key provisions of the NESHAPs, designed to protect public health, allowing the industry to avoid complying with standards that are applied to other industries.

STATES:

In 2009, EPA Administrator Lisa Jackson issued a ruling on a Title V petition holding that states must assess whether oil and natural gas operations should be aggregated in accordance with longstanding EPA policies governing New Source Review and Title V permitting.[25] States should follow the EPA's recent guidance and ensure that emissions from oil and gas operations are appropriately aggregated to ensure compliance with New Source Review and Title V. Aggregation provides an important opportunity to more accurately recognize integrated source operations under the Clean Air Act and ensure that oil and gas operations are regulated on a cumulative basis under New Source Review and Title V.

Until strong new rules are in place, the oil and natural gas industry can and should **voluntarily invest in equipment that reduces pollution escaping to the air**. Such equipment is readily available and financially profitable for companies. These investments would increase efficiency and production and reduce cancer causing chemicals from being emitted into the air in communities near production facilities –saving lives and protecting the health of neighboring families.

As the natural gas industry continues to grow, so will the number of families neighboring and affected by the emissions. Industry and government leaders have a unique opportunity to address public health and environmental issues by implementing these recommendations. For coexistence between communities and industry to be possible, chemical exposure has to be immediately addressed.

[25] http://www.epa.gov/region7/air/title5/t5memos/oilgaswithdrawal.pdf

Greater focus needed on methane leakage from natural gas infrastructure

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Contributed by Stephen W. Pacala, February 13, 2012 (sent for review December 21, 2011)

Natural gas is seen by many as the future of American energy: a fuel that can provide energy independence and reduce greenhouse gas emissions in the process. However, there has also been confusion about the climate implications of increased use of natural gas for electric power and transportation. We propose and illustrate the use of technology warming potentials as a robust and transparent way to compare the cumulative radiative forcing created by alternative technologies fueled by natural gas and oil or coal by using the best available estimates of greenhouse gas emissions from each fuel cycle (i.e., production, transportation and use). We find that a shift to compressed natural gas vehicles from gasoline or diesel vehicles leads to greater radiative forcing of the climate for 80 or 280 yr, respectively, before beginning to produce benefits. Compressed natural gas vehicles could produce climate benefits on all time frames if the well-to-wheels CH_4 leakage were capped at a level 45–70% below current estimates. By contrast, using natural gas instead of coal for electric power plants can reduce radiative forcing immediately, and reducing CH_4 losses from the production and transportation of natural gas would produce even greater benefits. There is a need for the natural gas industry and science community to help obtain better emissions data and for increased efforts to reduce methane leakage in order to minimize the climate footprint of natural gas.

With growing pressure to produce more domestic energy and to reduce greenhouse gas (GHG) emissions, natural gas is increasingly seen as the fossil fuel of choice for the United States as it transitions to renewable sources. Recent reports in the scientific literature and popular press have produced confusion about the climate implications of natural gas (1–5). On the one hand, a shift to natural gas is promoted as climate mitigation because it has lower carbon per unit energy than coal or oil (6). On the other hand, methane (CH_4), the prime constituent of natural gas, is itself a more potent GHG than carbon dioxide (CO_2); CH_4 leakage from the production, transportation and use of natural gas can offset benefits from fuel-switching.

The climatic effect of replacing other fossil fuels with natural gas varies widely by sector (e.g., electricity generation or transportation) and by the fuel being replaced (e.g., coal, gasoline, or diesel fuel), distinctions that have been largely lacking in the policy debate. Estimates of the net climate implications of fuel-switching strategies should be based on complete fuel cycles (e.g., "well-to-wheels") and account for changes in emissions of relevant radiative forcing agents. Unfortunately, such analyses are weakened by the paucity of empirical data addressing CH_4 emissions through the natural gas supply network, hereafter referred to as CH_4 leakage.* The U.S. Environmental Protection Agency (EPA) recently doubled its previous estimate of CH_4 leakage from natural gas systems (6).

In this paper, we illustrate the importance of accounting for fuel-cycle CH_4 leakage when considering the climate impacts of fuel-technology combinations. Using EPA's estimated CH_4 emissions from the natural gas supply, we evaluated the radiative forcing implications of three U.S.-specific fuel-switching scenarios: from gasoline, diesel fuel, and coal to natural gas.

A shift to natural gas and away from other fossil fuels is increasingly plausible because advances in horizontal drilling and hydraulic fracturing technologies have greatly expanded the country's extractable natural gas resources particularly by accessing gas stored in shale deep underground (7). Contrary to previous estimates of CH_4 losses from the "upstream" portions of the natural gas fuel cycle (8, 9), a recent paper by Howarth et al. calculated upstream leakage rates for shale gas to be so large as to imply higher lifecycle GHG emissions from natural gas than from coal (1). (*SI Text*, discusses differences between our paper and Howarth et al.) Howarth et al. estimated CH_4 emissions as a percentage of CH_4 produced over the lifecycle of a well to be 3.6–7.9% for shale gas and 1.7–6.0% for conventional gas. The EPA's latest estimate of the amount of CH_4 released because of leaks and venting in the natural gas network between production wells and the local distribution network is about 570 billion cubic feet for 2009, which corresponds to 2.4% of gross U.S. natural gas production (1.9–3.1% at a 95% confidence level) (6).† EPA's reported uncertainty appears small considering that its current value is double the prior estimate, which was itself twice as high as the previously accepted amount (9).

Comparing the climate implications of CH_4 and CO_2 emissions is complicated because of the much shorter atmospheric lifetime of CH_4 relative to CO_2. On a molar basis, CH_4 produces 37 times more radiative forcing than CO_2.‡ However, because CH_4 is oxidized to CO_2 with an effective lifetime of 12 yr, the integrated, or cumulative, radiative forcings from equi-molar releases of CO_2 and CH_4 eventually converge toward the same value. Determining whether a unit emission of CH_4 is worse for the climate than a unit of CO_2 depends on the time frame considered. Because accelerated rates of warming mean ecosystems and humans have less time to adapt, increased CH_4 emissions due to substitution of natural gas for coal and oil may produce undesirable climate outcomes in the near-term.

The concept of global warming potential (GWP) is commonly used to compare the radiative forcing of different gases relative

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The authors declare no conflict of interest.

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*Challenges also exist in the quantification of CH_4 emissions from the extraction of coal. We use the term "leakage" for simplicity and define it broadly to include all CH_4 emissions in the natural gas supply, both fugitive leaks as well as vented emissions.

†This represents an uncertainty range between −19% and +30% of natural gas system emissions. For CH_4 from petroleum systems (35% of which we assign to the natural gas supply) the uncertainty is −24% to +149%; however, this is only a minor effect because the portion of natural gas supply that comes from oil wells is less than 20%.

‡One-hundred-two times on a mass basis. This value accounts for methane's direct radiative forcing and a 40% enhancement because of the indirect forcing by ozone and stratospheric water vapor (10).

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ENVIRONMENTAL SCIENCES

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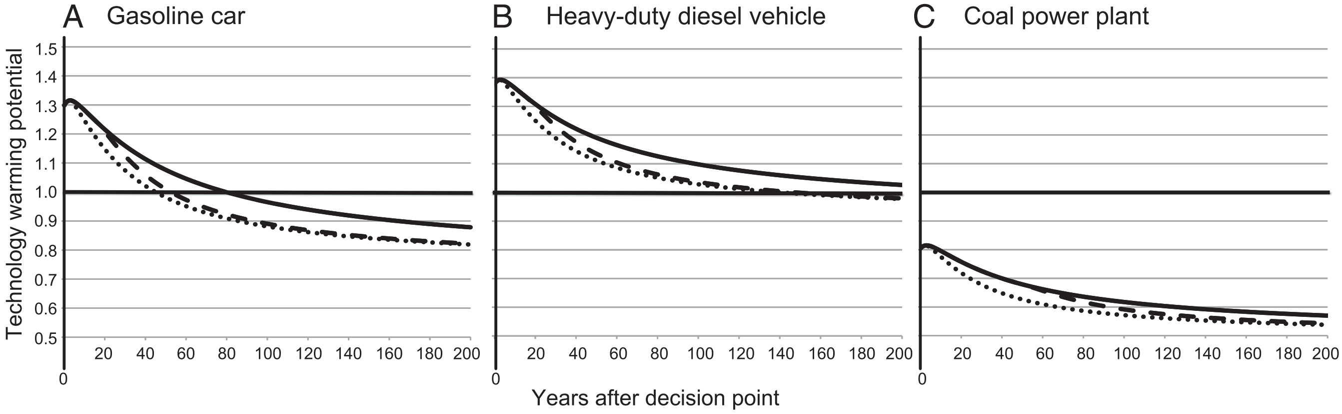

Fig. 1. Technology warming potential (TWP) for three sets of natural gas fuel-switching scenarios. (*A*) CNG light-duty cars vs. gasoline cars; (*B*) CNG heavy-duty vehicles vs. diesel vehicles; and (*C*) combined-cycle natural gas plants vs. supercritical coal plants using low-CH_4 coal. The three curves within each frame simulate real-world choices, including a single emissions pulse (dotted lines); emissions for the full service life of a vehicle or power plant (15 and 50 years, respectively, dashed lines); and emissions from a converted fleet continuing indefinitely (solid lines). For the pulse and service life analyses, our scenarios assume that the natural gas choice reverts back to the incumbent choice before the switch took place; for the fleet conversion analysis we assume that a natural gas vehicle or power plant is replaced by an identical unit at the end of its service life.

to CO_2 and represents the ratio of the cumulative radiative forcing *t* years after emission of a GHG to the cumulative radiative forcing from emission of an equivalent quantity of CO_2 (10). The Intergovernmental Panel on Climate Change (IPCC) typically uses 100 yr for the calculation of GWP. Howarth et al. (1) emphasized the 20-year GWP, which accentuates the large forcing in early years from CH_4 emissions, whereas Venkatesh et al. (2) adopted a 100-yr GWP and Burnham et al. (4) utilized both 20- and 100-yr GWPs.

GWPs were established to allow for comparisons among GHGs at one point in time after emission but only add confusion when evaluating environmental benefits or policy tradeoffs over time. Policy tradeoffs like the ones examined here often involve two or more GHGs with distinct atmospheric lifetimes. A second limitation of GWP-based comparisons is that they only consider the radiative forcing of single emission pulses, which do not capture the climatic consequences of real-world investment and policy decisions that are better simulated as emission streams.

To avoid confusion and enable straightforward comparisons of fuel-technology options, we suggest that plotting as a function of time the relative radiative forcing of the options being considered would be more useful for policy deliberations than GWPs. These technology warming potentials (TWP) require exactly the same inputs and radiative forcing formulas used for GWP but reveal time-dependent tradeoffs inherent in a choice between alternative technologies. We illustrate the value of our approach by applying it to emissions of CO_2 and CH_4 from vehicles fueled with CNG compared with gasoline or diesel vehicles and from power plants fueled with natural gas instead of coal.

Wigley also analyzed changes in the relative benefits over time of switching from coal to natural gas, but that was done in the context of additional complexities including specific assumptions about the global pace of technological substitution, emissions of sulfur dioxide and black carbon, and a specific model of global warming due to radiative forcing (5). We compare our results with Wigley's in the next section.

Results and Discussion

We focus on the TWPs of real-world choices faced by individuals, corporations, and policymakers about fuel-switching in the transport and power sectors. Each of the three curves within the panels of Fig. 1 represents a distinct choice and its associated emission duration: for example, whether to rent a CNG or a gasoline car for a day (Pulse TWP); whether to purchase and operate a CNG or gasoline car for a 15-yr service life (Service-Life TWP); and whether a nation should adopt a policy to convert the gasoline fleet of cars to CNG (Fleet Conversion TWP). In each of these cases, a TWP greater than 1 means that the cumulative radiative forcing from choosing natural gas today is higher than a current fuel option after *t* yr. Our results for pulse TWP at 20 and 100 yr are identical to fuel-cycle analyses using 20-year or 100-year GWPs for CH_4.

Given EPA's current estimates of CH_4 leakage from natural gas production and delivery infrastructure, in addition to a modest CH_4 contribution from the vehicle itself (for which few empirical data are available), CNG-fueled vehicles are not a viable mitigation strategy for climate change.[§] Converting a fleet of gasoline cars to CNG increases radiative forcing for 80 yr before any net climate benefits are achieved; the comparable cross-over point for heavy-duty diesel vehicles is nearly 300 yr.

Stated differently, converting a fleet of cars from gasoline to CNG would result in numerous decades of more rapid climate change because of greater radiative forcing in the early years after the conversion. This is eventually offset by a modest benefit. After 150 yr, a CNG fleet would have produced about 10% less cumulative radiative forcing than a gasoline fleet—a benefit equivalent to a fuel economy improvement of 3 mpg in a 30 mpg fleet. CNG vehicles fare even less favorably in comparison to heavy-duty diesel vehicles.

In contrast to the transportation cases, a fleet of new, combined-cycle natural gas power plants reduces radiative forcing on all time frames, relative to new coal plants burning low-CH_4 coal—assuming current estimates of leakage rates (Fig. 1*C*). The conclusions differ primarily because of coal's higher carbon content relative to petroleum fuels; however, fuel-cycle CH_4 leakage can also affect results. (As discussed elsewhere in this paper, our analysis considered only the emissions of CH_4 and CO_2. In *SI Text*, we examine the effect of different CH_4 leak rates in the coal and natural gas fuel cycles for the electric power scenario.)

To provide guidance to industry and policymakers, we also determined the maximum well-to-wheels or well-to-burner-tip leakage rate needed to ensure net climate benefits on all time frames after fuel-switching to natural gas (see Fig. 2). For example, if the well-to-wheels leakage was reduced to an effective leak rate of 1.6% of natural gas produced (approximately 45% below our estimate of current leakage of 3.0%), CNG cars would result

[§]The CH_4 from operation of a CNG automobile was estimated to be 20 times the value for gasoline vehicles (11), which is approximately 20% of the well-to-pump CH_4 leakage on a kg/mmBtu basis. This assumption deserves much further scrutiny.

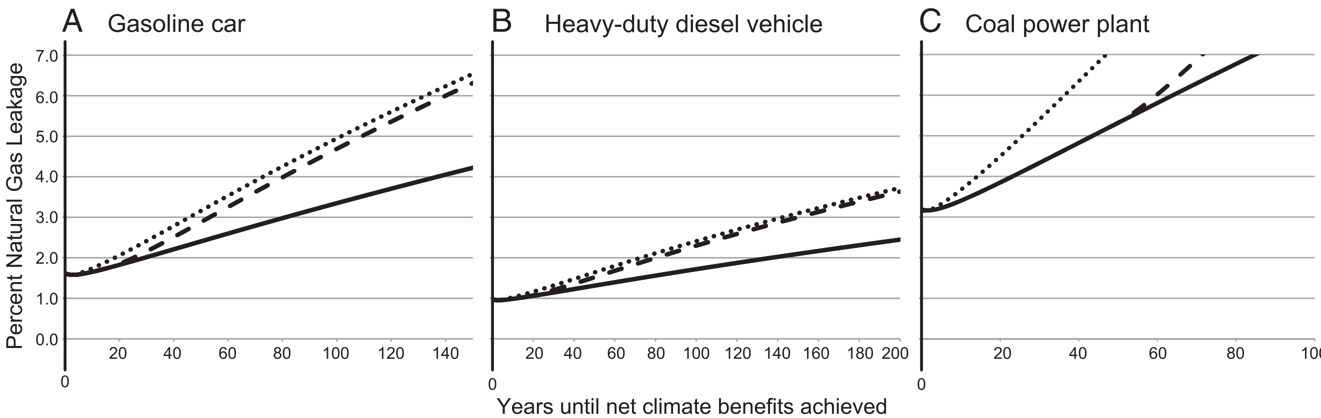

Fig. 2. Maximum "well-to-wheels" natural gas leak rate as a function of the number of years needed to achieve net climate benefits after choosing a CNG option in lieu of (*A*) gasoline cars; (*B*) heavy-duty diesel vehicles; and (*C*) coal power plants. For *A* and *B*, the maximum leakage is the sum of losses from the well through the distribution system plus losses from the CNG vehicle itself (well-to-wheels); for *C*, the maximum leakage is from the well through the transmission system where most power plants receive their fuel. When leak rates are less than the y-intercept, a fuel switch scenario would result in net climate benefits beginning immediately. The three curves within each frame follow the conventions outlined in Fig. 1 and represent: single emissions pulses (dotted lines); the service life of a vehicle or a power plant, 15 or 50 years, respectively (dashed lines); and a permanent fleet conversion (solid lines).

in climate benefits immediately and improve over time.[¶] For CNG to immediately reduce climate impacts from heavy-duty vehicles, well-to-wheels leakage must be reduced below 1%. Fig. 2*C* shows that new natural gas power plants produce net climate benefits relative to efficient, new coal plants using low-gassy coal on all time frames as long as leakage in the natural gas system is less than 3.2% from well through delivery at a power plant. Fig. 2 also shows, for a range of leakage rates, the number of years needed to reach the "cross-over point" when net climate benefits begin to occur after a fuel-technology choice is made.

We emphasize that our calculations assume an average leakage rate for the entire U.S. natural gas supply (as well for coal mining). Much work needs to be done to determine actual emissions with certainty and to accurately characterize the site-to-site variability in emissions. However, given limited current evidence, it is likely that leakage at individual natural gas well sites is high enough, when combined with leakage from downstream operations, to make the total leakage exceed the 3.2% threshold beyond which gas becomes worse for the climate than coal for at least some period of time.[||] Our analysis of reported routine emissions for over 250 well sites with no compressor engines in Barnett Shale gas well sites in Fort Worth, Texas, in 2010 revealed a highly skewed distribution of emissions, with 10% of well sites accounting for nearly 70% of emissions (see *SI Text*).[**] Natural gas leak rates calculated based on operator-reported, daily gas production data at these well sites ranged from 0% to 5%, with six sites out of 203 showing leak rates of 2.6% or greater due to routine emissions alone.[††]

Our analysis of coal-to-natural gas fuel-switching does not consider potential changes in sulfate aerosols and black carbon, short-lived climate forcers previously shown to affect the climate implications of such fuel-switching scenarios (5, 13). Recently, Wigley concluded that coal-to-gas switching on a global scale would result in increased warming on a global scale in the short term, based on examining a set of scenarios with a climate model that included both the increased warming produced by CH_4 losses from the natural gas fuel cycle and the additional cooling that occurs due to SO_2 emissions and the sulfate aerosols they form as a result of burning coal (5). The applicability of Wigley's global conclusion to the United States or any other individual country is limited due to the reliance on global emissions scenarios. Analyses such as Wigley's, which model the climate impacts of all climate forcing emissions, are useful to evaluate specific fuel-switching scenarios; however, their ultimate relevance to policymakers and fleet owners will be determined by the fidelity with which they reflect actual emissions from all phases of each fuel cycle at the relevant geographic scale (e.g., national, continental, or global). The SO_2 emissions that Wigley assumed are much higher than those of the current fleet of coal electrical generation plants in the United States, where SO_2 emissions declined by more than 50% between 2000 and 2010.[‡‡] Moreover, due to state and federal pollution abatement requirements, U.S. SO_2 emissions are projected to continue declining, to roughly 30% of 2000 levels by 2014 (see *SI Text*). This means that by 2014 the projected sulfur emissions from the U.S. coal electrical generation plant fleet, 3 TgS/GtC, will approach the emission factor that Wigley assumed the global fleet would reach in 2060 (2 TgS/GtC), when he projected the climate benefits of fuel-switching might begin, and significantly lower than Wigley's estimated 2010 value of 12 TgS/GtC. Accounting for the lower SO_2 from U.S. coal plants in an integrated way will result in greater net climate impacts of using coal than reported by Wigley and in turn the net benefits of fuel-switching will occur much sooner than he projected.

Increasingly, this will also be the case globally. The production of sulfur aerosols as a result of coal combustion causes such negative impacts on human and ecosystem health that it is prudent to assume that policies will continue to be rapidly implemented in many, if not most, countries to reduce such emissions at a much faster pace than assumed by Wigley. Indeed, it has been reported that China has already installed SO_2 scrubbers on power plants accounting for over 70% of the nation's installed coal power capacity (14), such that SO_2 emissions from power plants in 2010 were 58% below 2004 levels (15). The SO_2 emissions factor from

[¶]Our estimate that current well-to-wheels leakage is 3.0% of gas produced assumes that 2.4% of gas produced is lost between the well and the local distribution system (based on EPA's 2011 GHG emission inventory) and that 0.6% is due to emissions during refueling and from the vehicle itself. For further discussion of the climatic implication of natural gas vehicles see (12).

[||]EPA's GHG inventory suggests leakage from natural gas processing and transmission is 0.6% of gas produced, meaning production leakage must be greater than 2.6% for the total fuel cycle leakage of a power plant receiving fuel from a transmission pipeline to exceed 3.2%.

[**]Sites with compressor engines were excluded due to the contractor's assumption that all engines in the City were uncontrolled, which leads to erroneous emission estimates.

[††]Routine emissions do not include such occasional events as well completions and blowdowns. Only 203 of the 254 sites had data for gas production. An Excel spreadsheet containing the Fort Worth data and our calculations is provided in Dataset S1.

[‡‡]Emissions query performed on December 5, 2011, using the Data and Maps feature of the U.S. Environmental Protection Agency's Clean Air Markets Web page (http://camddataandmaps.epa.gov/gdm/).

Chinese coal plants in 2010 has been estimated to be 204 g/GJ, comparable to the 2010 value of 229 g/GJ (4.7 TgS/GtC) for U.S. coal plants (*SI Text*).

Little work appears to have been done to evaluate fuel-switching in on-road transportation with methods that consider the implications of all climate forcing emissions, including sulfur aerosols and black carbon, although the effect of short-lived climate forcers on individual transport sectors has been studied (16, 17). One study reports that the influence of negative radiative forcing due to emissions from on-road transport is much lower than for the power generation sector in both the United States and globally (18). This implies that our approach, which considers CO_2 and CH_4 emissions alone, provides a reasonable first-order estimate of changes in radiative forcing from fuel-switching scenarios for the on-road transport sector.

Conclusions

The TWP Approach Proposed Here Offers Policymakers Greater Insights than Conventional GWP Analyses. GWPs are a valuable tool to compare the radiative forcing of different gases but are not sufficient when thinking about fuel-switching scenarios. TWPs provide a transparent, policy-relevant analytical approach to examine the time-dependent climate influence of different fuel-technology choices.

Improved Science and Data Are Needed. Despite recent changes to EPA's methodology for estimating CH_4 leakage from natural gas systems, the actual magnitude remains uncertain and estimates could change as methods are refined. Ensuring a high degree of confidence in the climate benefits of natural gas fuel-switching pathways will require better data than are available today. EPA's rule requiring natural gas industry disclosure of GHG emissions should begin to produce data in 2012, though it is unlikely that most uncertainties will be resolved and possible systematic biases eliminated. Specific challenges include confirming the primary sources of emissions and determining drivers of variance in leakage rates. Greater direct involvement of the scientific community could help improve estimates of CH_4 leakage and identify approaches that enable independent validation of industry-reported emissions.

Reductions in CH_4 Leakage Are Needed to Maximize the Climate Benefits of Natural Gas. While CH_4 leakage from natural gas infrastructure and use remains uncertain, it appears that current leakage rates are higher than previously thought. Because CH_4 initially has a much higher effect on radiative forcing than CO_2, maintaining low rates of CH_4 leakage is critical to maximizing the climate benefits of natural gas fuel-technology pathways. Significant progress appears possible given the economic benefits of capturing and selling lost natural gas and the availability of proven technologies. (EPA's Natural Gas STAR program shows many examples: www.epa.gov/gasstar/tools/recommended.html.)

Table 2. Radiative efficiency (RE) values used in this paper

	Direct RE ($W\ m^{-2}\ ppb^{-1}$)	Relative direct + indirect RE (per ppb or molar basis)	Relative direct + indirect RE (per kg basis)*
CO_2	1.4×10^{-5}	1	1
CH_4	3.7×10^{-4}	37	102

*Obtained by multiplying the molar radiative efficiency by the ratio of molecular weights of CH_4 and CO_2.

Methods

Our approach of using TWPs to compare the cumulative radiative forcing of fuel-technology combinations is a straightforward extension of the calculation of GWP, which is given by Eq. **1** over a time horizon, TH, for a pulse emission of 1 kg of a generic GHG producing time-dependent radiative forcing given by $RF_{GHG}(t)$:

$$\mathrm{GWP} = \frac{\int_0^{\mathrm{TH}} \mathrm{RF}_{\mathrm{GHG}}(t)dt}{\int_0^{\mathrm{TH}} \mathrm{RF}_{\mathrm{CO_2}}(t)dt}. \qquad [1]$$

SI Text shows the analytical solution of Eq. **1** (i.e., GWP as a function of time horizon). Plotting the entire curve enables one to see the GWP values for all time horizons.

Our TWP approach extends the standard GWP calculation in two ways: by combining the effects of CH_4 and CO_2 emissions from technology-fuel combinations and by considering streams of emissions in addition to single pulses. Considering streams of emissions is more reflective of real-world scenarios that involve activities that occur over multiyear time frames.

Eq. **2** is our extension of the GWP formula Eq. **1** to calculate TWPs, with the following definitions. We label as Technology-1 the alternative that combusts natural gas and has CO_2 emissions E_{1,CO_2} and CH_4 emissions from the production, processing, storage, delivery, and use of the fuel: E_{1,CH_4}. If L_{REF} is the percent of gross natural gas produced that is currently emitted to the atmosphere over the relevant fuel cycle (e.g., electric power or transportation), then Technology-1's CH_4 emissions at leakage rate L would be: $(L/L_{REF})E_{1,CH_4}$. The calculations of TWP in this paper assume that the leakage rate L is at the national average value L_{REF} (and thus $L/L_{REF} = 1$). The scaling factor L/L_{REF} is included to allow calculations about changes in the national leakage rate or about individual wells and distribution networks that deviate from the national average. The values we used for L_{REF} are derived in *SI Text* using EPA's estimated emissions with one exception and are equal to 2.1% for a natural gas power plant and 3.0% for CNG vehicles. The exception to the last statement is that we estimated CH_4 from the operation of a CNG automobile to be 20 times that from a gasoline vehicle (11), which is approximately 20% of the well-to-pump CH_4 leakage on a kg/mmBtu basis. This assumption deserves much further scrutiny. Technology-2 combusts gasoline, diesel fuel, or coal and produces CO_2 emissions E_{2,CO_2} and methane emissions E_{2,CH_4}. Estimates of the Es for each of the technologies considered are reported in Table 1 and are explained in *SI Text*. The TWPs at each point in time can be obtained by substituting the total radiative forcing values, $TRF_{CH_4}(t)$ and $TRF_{CO_2}(t)$ for CH_4 and CO_2, respectively, and emission factors, $E_{n,GHG}$ from Table 1 into Eq. **2**:

Table 1. Emission factors used for TWP calculations in this paper

	Power Plants		Vehicles			
	Natural gas combined cycle* (kg/MW*h*)	Supercritical pulverized coal† (kg/MW*h*)	Light-duty CNG car (kg/mmBtuHHV)‡	Light-duty gasoline car (kg/mmBtuHHV)	Heavy-duty CNG truck (mg/ton-mile)	Heavy-duty diesel truck (mg/ton-mile)
Upstream CH_4	3.1	0.65	0.51	0.1	590	100
Upstream CO_2	36	7	9.4	15.9	10,000	15,000
In-Use CH_4	0	0	0.11	0.0056	15	0
In-Use CO_2	361	807	53.1	70.3	80,000	85,000
Fuel cycle CH_4	3.1	0.65	0.62	0.11	605	100
Fuel cycle CO_2	397	814	62.5	86.2	90,000	100,000

*Heat rate = 6,798 Btu/kWh.
†Heat rate = 8,687 Btu/kWh.
‡1 mmBtu = 10^6 Btu = 1.055 GJ.

Table 3. Total radiative forcing (TRF) functions for CH_4 and CO_2 used in calculation of TWP in Eq. 2 for three distinct emissions profiles

Case	$TRF_{CH_4}(t)$	$TRF_{CO_2}(t)$
Pulse TWP	$RE\{\tau_M(1-e^{-t/\tau_M})\}$	$a_0 t + \sum_{i=1}^{3} a_i\tau_i(1-e^{-t/\tau_i})$
Service Life TWP for $t \le AMAX$	$RE\{\tau_M t - \tau_M^2(1-e^{-t/\tau_M})\}$	$a_0\frac{t^2}{2} + \sum_{i=1}^{3} a_i(\tau_i t - \tau_i^2(1-e^{-t/\tau_i}))$
Service Life TWP for $t > AMAX$	$RE\{\tau_M AMAX - \tau_M^2 e^{-t/\tau_M}(e^{AMAX/\tau_M}-1)\}$	$a_0[AMAX\, t - \frac{AMAX^2}{2}] + \sum_{i=1}^{3} a_i(\tau_i AMAX - \tau_i^2 e^{-t/\tau_i}(e^{AMAX/\tau_i}-1))$
Fleet Conversion TWP	$RE\{\tau_M t - \tau_M^2(1-e^{-t/\tau_M})\}$	$a_0\frac{t^2}{2} + \sum_{i=1}^{3} a_i(\tau_i t - \tau_i^2(1-e^{-t/\tau_i}))$

RE in these formulas is the radiative efficiency of CH_4 relative to CO_2 and equals 102.

$$\mathrm{TWP}(t) = \frac{\frac{L}{L_{\mathrm{REF}}} E_{1,\mathrm{CH_4}} \mathrm{TRF_{CH_4}}(t) + E_{1,\mathrm{CO_2}} \mathrm{TRF_{CO_2}}(t)}{E_{2,\mathrm{CH_4}} \mathrm{TRF_{CH_4}}(t) + E_{2,\mathrm{CO_2}} \mathrm{TRF_{CO_2}}(t)}. \quad [2]$$

The TRF values needed for Eq. **2** are derived as follows. Let $f(t, t_E)$ be the mass of a gas left in the atmosphere at time t if 1 kg of the gas was emitted at time t_E. The cumulative radiative forcing function, $\mathrm{CRF}(t)$ (in units of $\mathrm{J\,m^{-2}\,kg^{-1}}$), at a later time t, due to emission of 1 kg of the gas at time t_E, is then:

$$\mathrm{CRF}(t) \equiv \int_{t_E}^{t} \mathrm{RE}\, f(x, t_E)dx, \quad [3]$$

where RE is the radiative efficiency of the gas. The integral in Eq. **3** sums radiative forcing for the $t - t_E$ years from the year in which the gas was emitted, $x = t_E$, to year $x = t$. For simplicity, we adopt units which make the RE of CO_2 equal to one, and so the RE of CH_4 is expressed as a multiple of the RE of CO_2. In these units, the RE of CH_4 is determined to be 102, using the values in Table 2 taken from the IPCC (10) and following the IPCC convention that methane's direct radiative efficiency be enhanced by 25% and 15% to account for indirect forcing due to ozone and stratospheric water, respectively.

Now suppose that instead of a single pulse, the gas is emitted continuously at a rate of 1 kg/yr from $t = 0$ until some maximum time t_{max}, as would occur, for example, if emissions were to continue over the service life of a vehicle, power plant, or fleet. For such cases we define the total radiative forcing (TRF) in year t to be:

$$\mathrm{TRF}(t) \equiv \int_{0}^{t_{\max}} \int_{t_E}^{t} \mathrm{RE}\, f(x, t_E)dx\, dt_E. \quad [4]$$

In the special case of a single emission pulse, $\mathrm{TRF}(t) = \mathrm{CRF}(t)$. Our use of Eq. **4** assumes a constant, unit emission rate; a more general formulation could be employed to reflect potential technology improvements over time.

For CH_4, $f(t, t_E)$ is an exponential decay:

$$f(t, t_E) = e^{-\frac{t - t_E}{\tau_M}}, \quad [5]$$

where τ_M is 12 yr. For CO_2, we follow the IPCC and use the Bern carbon cycle model (10):

$$f(t, t_E) = a_0 + \sum_{i=1}^{3} a_i e^{-\frac{t - t_E}{\tau_i}} \quad [6]$$

where $\tau_1 = 172.9$, $\tau_2 = 18.51$, $\tau_3 = 1.186$, $a_0 = 0.217$, $a_1 = 0.259$, $a_2 = 0.338$, and $a_3 = 0.186$. Our calculations do not consider the CO_2 produced from the oxidation of CH_4, an approximation which introduces a small underestimation of the radiative forcing from a fuel cycle's CH_4 leakage.

If calculating the TWP for a single pulse of emissions (pulse TWP), then $t_E = 0$; $\mathrm{TRF_{CH_4}}(t)$ is given by Eq. **3** with $f(t, t_E)$ given by Eq. **5**; and $\mathrm{TRF_{CO_2}}(t)$ is given by Eq. **3** with $f(t, t_E)$ given by Eq. **6**. If calculating the TWP for a permanent fuel conversion of a fleet (fleet conversion TWP) then $\mathrm{TRF_{CH_4}}(t)$ is given by Eq. **4** with $t_{max} = t$ and $f(t, t_E)$ given by Eq. **5**. Similarly, $\mathrm{TRF_{CO_2}}(t)$ is given by Eq. **4** with $t_{max} = t$ and $f(t, t_E)$ given by Eq. **6**. If calculating the TWP for emissions over the service life of a vehicle or power plant (service life TWP) and $t \le \mathrm{AMAX}$, where AMAX is the average age at which the asset ceases to emit, then $TRF_{CH_4}(t)$ and $\mathrm{TRF_{CO_2}}(t)$ are the same as in the fleet conversion TWP calculations. However, if $t > \mathrm{AMAX}$, then $\mathrm{TRF_{CH_4}}(t)$ is given by Eq. **4** with $t_{max} = \mathrm{AMAX}$ and $f(t, t_E)$ given by Eq. **5**. Similarly, $\mathrm{TRF_{CO_2}}(t)$ is given by Eq. **4** with $t_{max} = \mathrm{AMAX}$ and $f(t, t_E)$ given by Eq. **6**. The solutions for all of these cases are in Table 3. We use $\mathrm{AMAX} = 15$ yr for vehicles and $\mathrm{AMAX} = 50$ yr for power plants.

By rearranging terms in Eq. **2** when $\mathrm{TWP} = 1$ to bring L to the left hand side, we obtain an equation for the relationship between the cross-over time (t^*—the time at which the two technologies have equal cumulative radiative forcing) and the percent leakage that makes this happen (L^*):

$$L^* = L_{\mathrm{REF}}\left\{\frac{E_{2,\mathrm{CH_4}}}{E_{1,\mathrm{CH_4}}} + \frac{E_{2,\mathrm{CO_2}} - E_{1,\mathrm{CO_2}}}{E_{1,\mathrm{CH_4}}}\frac{\mathrm{TRF_{CO_2}}(t^*)}{\mathrm{TRF_{CH_4}}(t^*)}\right\}. \quad [7]$$

Taking the limit of L^* as the cross-over time t^* goes to zero, we obtain an expression for the critical leakage rate L_0, which serves as an approximation of the leakage rate below which the natural gas-burning technology causes less radiative forcing on all time frames.

$$L_0 = L_{\mathrm{REF}}\left\{\frac{E_{2,\mathrm{CH_4}}}{E_{1,\mathrm{CH_4}}} + \frac{E_{2,\mathrm{CO_2}} - E_{1,\mathrm{CO_2}}}{\mathrm{RE}\ \mathrm{E}_{1,\mathrm{CH_4}}}\right\} \quad [8]$$

where $\mathrm{RE} = 102$. Eq. **8** must be viewed as an approximation because L^* is a nonmonotonic function of t^* for small values of t^* (see Fig. 2, which plots L^* as a function of cross-over time t^*). The small decrease in L^* for small t^* is caused by the fact that 18.6% of the emitted CO_2 decays faster than CH_4 in the Bern carbon cycle model (time scales of 1.186 vs. 12 yr). The large increase in L^* for $t_* > 3$ years is caused by the rapid decay of CH_4 relative to the remaining 81.4% of the CO_2. The decay curves for CO_2 and CH_4 are shown in *SI Text*. Calculated values of L_o using Eq. **8** are within 2–3% of the absolute minima for L^*. Calculations of TWP and L^* using Eq. **2** and Eq. **8** were performed with an Excel spreadsheet and are available in Dataset S1.

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Pennsylvania Energy Impacts Assessment

Report 1: Marcellus Shale Natural Gas and Wind

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1. The Nature Conservancy – Pennsylvania Chapter
2. Western Pennsylvania Conservancy – Pennsylvania Natural Heritage Program
3. Audubon Pennsylvania

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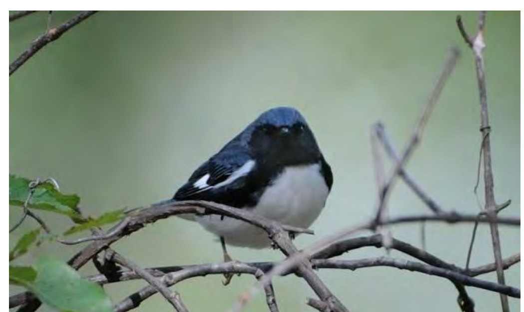
Executive Summary

Forest landscape along the West Branch Susquehanna River, Clinton County. © George C. Gress / TNC

Within a few weeks during the summer of 2000, eight towers rose two hundred feet above an agricultural field on a low ridge top along the Pennsylvania Turnpike. Not long after, large blades began sweeping the Somerset County sky as Pennsylvania's first industrial wind facility went on line. Several years later and an hour drive to the west, an unusual natural gas well was drilled over a mile down and pumped full of water. That well in Washington County yielded a surprising amount of gas flowing from fractures in a shale formation that geologists had long suspected held plenty of gas but has been too expensive to develop. Meanwhile, a Canadian company bought a small sawmill in Mifflintown and started producing wood pellets for stoves, boilers, and electric plants. It soon became one of the region's largest producers of wood biomass energy supplies. In the decade since, these three new energy technologies have expanded rapidly across the state. By the end of this year, 500 wind turbines will be turning on Pennsylvania ridgelines, nearly 1,800 Marcellus natural gas wells will be scattered across rolling fields and forests, and over 50 facilities will be producing wood pellets or burning wood for energy. Thousands of miles of pipelines and powerlines already crisscross the state to get energy supplies to major markets in the Northeast.



Black-throated blue warblers and other interior forest species could be impacted by forest fragmentation caused by energy development. © Gary Irwin

Each of these energy sources carries both promise and risk for people and nature. The promise is that wind, natural gas, and wood biomass energy can reduce greenhouse gas emissions, generate jobs, and increase energy security. The risk is that extensive land use change and loss of natural habitats could accompany new energy development and transmission lines. Impacts to priority conservation habitats across the state have been modest thus far. For example, aerial photo analysis indicates Marcellus gas development has so far cleared just 3,500 acres of forest (about 1,000 acres for wind turbines). An additional 8,500 acres of forest is now within 300 feet of new fragmenting edges created by well pads, and associated roads and infrastructure (5,000 acres for wind turbines). This fragmentation deprives "interior" forest species, such as black-throated blue warblers, northern goshawks, salamanders, and many woodland flowers, of the shade, humidity and tree canopy protection that only deep forest environments can provide.

By all accounts, each of these energy types is likely to grow substantially in Pennsylvania during the next two decades. The Marcellus shale formation, which underlies two-thirds of the state, is now believed to be one of the largest unconventional shale gas reserves in the world. The Pennsylvania Alternative Energy Portfolio Standards Act of 2004, along with state and federal incentives, will likely boost expansion of wind, wood biomass, and other alternative energy types over the next two decades. But, how much of each energy type might be developed? What transmission infrastructure will be needed to get more electric power and natural gas to consumers? And, where are these energy types most likely to be developed? How does the likely scale and location of future energy development overlap with priority conservation areas? The Pennsylvania Energy Impacts Assessment seeks answers to these questions so that conservationists can work more effectively with energy companies and government agencies to avoid, minimize or mitigate habitat impacts in the future.

Nine Mile Run Creek in PA's North Central Highlands © George C. Gress / TNC.

Assessment Goal: Develop credible energy development projections and assess how they might affect high priority conservation areas across Pennsylvania. Marcellus natural gas, wind, wood biomass, and associated electric and gas transmission lines were chosen as the focus since these energy types have the most potential to cause land-use change in the state over the next two decades. The conservation impacts focus is on forest, freshwater, and rare species habitats. The assessment **does not** address other potential environmental impacts, including water withdrawal, water quality, air quality and migratory pathways for birds and bats. The assessment also does not address a range of other social, economic, and climate characteristics of these energy types.

Key Assumptions: Any assessment of future trends must include certain assumptions. Among the most important assumptions of the Pennsylvania Energy Impacts Assessment are the following:

- A 20-year time period is used to assess potential cumulative habitat impacts from energy development;
- Given uncertainties about how energy prices could change, it was assumed that prices and capital investment (and policy and social conditions) will be sufficient to promote steady development growth for each energy type during the next two decades;
- Given uncertainty about how technology changes could affect spatial footprints, it was assumed that spatial footprints per well pad, turbine, and mile of transmission line will not change significantly during the next two decades;
- Given the proprietary nature of data on leases, Marcellus Shale porosity, fine resolution wind power, etc., all projections are based on publicly available information;
- It was assumed that recent trends and patterns of energy development will continue for the next two decades absent significant changes in government policies and industry practices;

Energy projections contained in this assessment are informed scenarios – **not predictions** – for how much energy development might take place and where it is more and less probable. Projected impacts, however, are based on measurements of actual spatial footprints measured for hundreds of well pads and wind turbines.

Analytical Steps: Key analytical steps for the Pennsylvania Energy Assessment included:

1) *Data collection* – Over 50 spatial data layers on energy resources, development permits, road and transmission infrastructure, physical features, and conservation priorities were compiled for the assessment;

2) *Spatial footprint analysis* – Spatial footprints for Marcellus gas well and wind turbine pads, associated roads, associated pipelines, associated electric transmission lines, and associated other clearings (*e.g.*, gas containment pits, equipment staging areas, electrical substations) were digitized using aerial photos of sites before and after construction;

3) *Scale projections* – Low, medium, and high scenarios for ***how much*** Marcellus Shale natural gas, wind, wood biomass, and transmission line development might occur were based as much as possible on existing projections and data from credible sources.

4) *Geographic projections* – Projections of ***where*** new Marcellus natural gas and wind energy development is more and less likely to occur were based on modeling the probability of a map pixel's land-use change to energy production based on sets of drivers and constraints developed for each energy type. Geographic projections for wood biomass and energy transmission were not modeled due to a lack of data. Conclusions about regional patterns of wood biomass and transmission development and potential conservation impacts will be presented in Report 2 of the Pennsylvania Energy Impacts Assessment.

5) *Conservation impacts analysis* – The potential impacts of future energy development were assessed for forest and freshwater habitats across the state. In addition, sites recognized as important for species of conservation concern were assessed. Conservation datasets for these assessments included, among others, large forest patches from The Nature Conservancy and the Western Pennsylvania Conservancy, habitat areas for rare species from the Pennsylvania Natural Heritage Program, densities for interior forest nesting bird species from the 2nd Pennsylvania Breeding Bird Atlas, and intact watersheds for native brook trout populations from the Eastern Brook Trout Joint Venture.

6) *Review* – A dozen energy experts in government, industry, and research organizations provided technical review of the energy projections.

Energy Projections: The Pennsylvania Energy Impacts Assessment developed low, medium and high scenarios for the amount of energy development that might take place in Pennsylvania by 2030. The projections include:

- *Marcellus Shale* – Sixty thousand wells could be drilled on between 6,000 and 15,000 new well pads (there are currently about 1,000) , depending on how many wells are placed on each pad. Gas development will occur in at least half of the state's counties, with the densest development likely in 15 counties in southwest, north central, and northeast Pennsylvania.

- *Wind* – Between 750 and 2,900 additional wind turbines could be built (there are currently about 500), depending on the wind share of electric generation by 2030. Most turbines would be built along the Allegheny Front in western Pennsylvania and on high Appalachian ridgetops in the central and northeastern parts of the state.

- *Wood Biomass* – Wood biomass energy demand could double or even triple today's wood energy use, depending on whether and how many coal power plants co-fire with wood biomass. Wood biomass energy development is likely to be widespread across the state in all three scenarios.

- *Transmission Lines* – Preliminary findings indicate between 10,000 and 15,000 miles of new high-voltage power lines and gas pipelines (especially gathering lines) could be built during the next twenty years. There is considerable uncertainty about exactly where these lines will be built but recently proposed electric and gas transmission lines provide insights into potential habitat impacts.

Conservation Impacts: This first Pennsylvania Energy Impacts Assessment report focuses on the overlap between likely Marcellus gas and wind development areas and Pennsylvania's most important natural habitats. A second report will focus on the potential for additional impacts from new wood biomass energy plants, electric power lines, and natural gas pipelines. Key findings for impacts from Marcellus natural gas and for wind development include:

Forests. By 2030, a range of between 34,000 to 82,000 acres of forest cover could be cleared by new Marcellus gas development in the state. Forest clearing for the wind development scenarios is much smaller, ranging from 1,000 to 4,500 acres. Such clearings would create new forest edges where the risk of predation, changes in light and humidity levels, and expanded presence of invasive species could threaten forest interior species in 85,000 to 190,000 forest acres adjacent to Marcellus development and 5,400 to 27,000 forest acres adjacent to wind development. Forest impacts will be concentrated in the north central and southwest parts of the state where many of the state's largest and most intact forest patches could be fragmented into smaller patches by well pads, roads, and other infrastructure. Impacts to forest interior species will vary depending on their geographic distribution and density. Some species, such as the black-throated blue warbler, could see widespread impacts to their relatively restricted breeding habitats in the state while widely distributed species, such as the Scarlet Tanager, would be relatively less affected. Locating energy infrastructure in open areas or toward the outer edges of large patches can significantly reduce impacts to important forest areas.


Brook trout © TNC

Freshwater. Aquatic habitats are at risk too. Once widespread, healthy populations of native eastern brook trout in Pennsylvania are now largely confined to small mountain watersheds. Nearly 80 percent of the state's most intact brook trout watersheds could see at least some Marcellus gas and wind development during the next twenty years. Strongholds for brook trout are concentrated in north central Pennsylvania, where Marcellus development is projected to be relatively intensive in over half of the state's best brook trout watersheds. Exceptional Value streams – the Department of Environmental Protection's highest quality designation – could see hundreds of well pads (perhaps 300 - 750) and dozens of wind turbines (perhaps 50 – 200) located within one-half mile under the projections. Because many intact brook trout and EV streams are in steep terrain, rigorous sediment controls, and possibly additional setback measures, are needed to help conserve these sensitive habitats.

Rare Species. Nearly 40 percent of Pennsylvania's globally rare and Pennsylvania threatened species can be found in areas with high potential for Marcellus gas development. These species tend to be associated with riparian areas, streams, and wetlands, while others are concentrated in unusually diverse areas such as the Youghiogheny Gorge. A handful of rare species have most or all of their known locations in high potential areas for Marcellus gas development. For example, three-fourths of all known snow trillium populations are in high potential Marcellus development areas as are all known populations for the green salamander. A much smaller number of known locations for globally and state rare species overlap with high potential wind development sites and they tend to be associated with rocky outcrops and ridgetop barrens habitats. Species with the greatest overlaps include timber rattlesnakes, Allegheny woodrats, and northern long-eared Myotis bats. More intensive surveys for globally rare and state critically endangered species in high potential Marcellus and wind development areas could help to minimize impacts before development begins. The Pennsylvania Game Commission is working with wind companies and other researchers to assess impacts to migratory pathways for birds and bats.

Recreation. Extensive overlaps are projected between Marcellus development and state forests, state parks, and state game lands. Just over ten percent of Pennsylvania's public lands are legally protected from gas development, most of it within State Wild and Natural Areas or in state parks where the Commonwealth owns the mineral rights. The state does not own mineral rights for 80% of State Park and State Game Lands, nearly 700,000 acres of State Forests have already been leased, and only about 300,000 acres of the remaining State Forest Lands are legally off-limits to future leases. Projections indicate between 900 and 2,200 well pads could be developed across all state lands, with most going on State Forest Lands, followed by State Game Lands, and State Parks. Wind development was not projected on state lands, though some facilities are projected near highly visited sites, including natural vistas.

Clearly, the heart of some of Pennsylvania's best natural habitats lie directly in the path of future energy development. Integrating information on conservation priorities into energy planning, operations, and policy by energy companies and government agencies sooner rather than later could dramatically reduce these impacts. Many factors – including energy prices, economic benefits, greenhouse gas reductions, and energy independence – will go into final decisions about where and how to proceed with energy development. Information about Pennsylvania's most important natural habitats should be an important part of the calculus about trade-offs and optimization as energy development proceeds. Would Pennsylvania's conservation pioneers, including Gifford Pinchot, Maurice Goddard, and Rachel Carson, expect anything less?

Marcellus Shale Natural Gas

Once thought to be inaccessible, deep shale formations with tightly held natural gas have become the most rapidly growing source of energy in North America. New technologies and methods have allowed companies to drill 6,000 to 10,000 feet down to reach the Marcellus shale, turn the well horizontally to follow the shale layer for a mile or more, and then pump in millions of gallons of water to fracture the shale and release the natural gas. Pennsylvania is at the epicenter of the Marcellus formation, one of the world's largest unconventional shale natural gas reserves. Situated right next door to huge markets in the Mid-Atlantic and Northeastern states, Marcellus gas development has expanded at a furious pace since the first wells were drilled just few years ago in Washington County. There are now nearly 2,000 drilled wells, most of them concentrated in the southwestern and northeastern parts of the state.

The Marcellus boom is bringing rapid economic growth to many rural communities that have been in economic decline for decades. Natural gas is also displacing higher carbon coal and oil supplies thus slowing the rise in greenhouse gas emissions. These benefits are real but not without costs. Large amounts of water must be withdrawn to frac each well (about 5 million gallons). The return flow water that comes back up from the well contains varying levels of chemicals, heavy metals, and even radioactive materials, and must be handled carefully to avoid spills when recycled or disposed. Heavy trucks and compressor stations rumble constantly in gas development areas putting heavy strains on roads, bridges and air quality. Because of known and perceived risks to environmental quality and human health, water use, air emissions and transportation demands are receiving growing attention from government agencies, researchers and energy companies. Thus far, relatively little attention, however, has been focused on Marcellus gas development impacts to natural habitats across the state.

What is Marcellus Shale Natural Gas?

The Marcellus is the largest gas-bearing shale formation in North America in both area and potential gas volume. It spans over 150,000 square miles across 5 states including the southern tier of New York, the northern and western half of Pennsylvania, the eastern third of Ohio, most of West Virginia, and a small slice of western Virginia. Estimates of the potential recoverable volume have increased steadily. The latest estimates by the U.S. Department of Energy are nearly 300 trillion cubic feet – enough to supply all natural gas demand in the United States for at least 10 years.

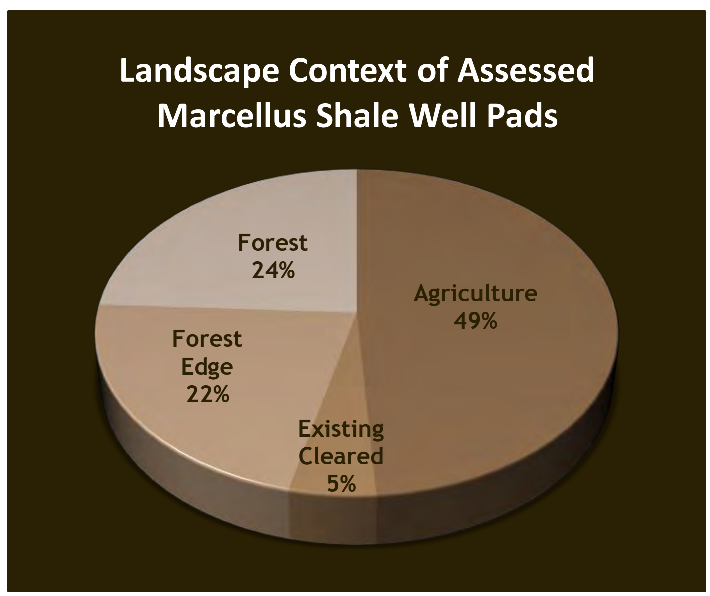
Map showing the extent of the Marcellus Shale formation. Data source: United States Geological Survey.

Geologists have long known the Marcellus formation is an organically-rich shale with potentially large amounts of natural gas, but it was too deep, too thin, and too dense to exploit. In 2005, Range Resources drilled the first production Marcellus well using horizontal drilling and hydraulic fracturing methods. The horizontal drilling is necessary because the shale is typically thin and vertical wells will only intercept a small part of the formation. Hydraulic fracturing (or "fracing") is a process that uses large volumes of water, sand, lubricants, and other chemicals to create small fissures in the shale rock. Hydro-fracing is necessary to release the gas which is tightly held in the dense black shale. These methods, first perfected for deep shale gas in the Barnett formation of Texas, unlocked the tremendous gas reserves in the Marcellus and other "unconventional" shale formations previously thought to be out of economic reach.

In contrast to shallow gas deposits in western Pennsylvania, the Marcellus is developed with multiple horizontal wells that can reach out 5,000 feet or more from one well pad. Everything about Marcellus development is bigger than conventional shallow gas plays. The well pads are more expansive (averaging just over 3 acres compared to a small fraction of an acre), the water used to frac wells is much greater (5 million gallons versus a hundred thousand gallons), and the supporting infrastructure is much larger in scale (24" diameter pipelines to gather gas from wells versus 2" or 4" pipelines in shallow fields). Individual wells are also vastly more productive (5 – 10 million cubic feet per day versus less than 100,000 cubic feet in peak early production). While the larger pad, greater water use, and more extensive infrastructure pose more challenges for conservation than shallow gas, the area "drained" by wells on each Marcellus pad is much larger than from shallow gas pads (500-1,000 acres versus 10-80 acres) since there are typically multiple lateral wells on a Marcellus pad versus a single vertical well on a shallow gas pad. The lateral reach of Marcellus wells means there is more flexibility in where pads and infrastructure can be placed relative to shallow gas. This increased flexibility in placing Marcellus infrastructure can be used to avoid or minimize impacts to natural habitats in comparison to more densely-spaced shallow gas fields.

Current and Projected Marcellus Shale Natural Gas Development

Projections of future Marcellus gas development impacts depend on robust spatial measurements for existing Marcellus well pads and infrastructure. We compared aerial photos of Pennsylvania Department of Environmental Protection (DEP) Marcellus well permit locations taken before and after development and precisely documented the spatial foot print of 242 Marcellus well pads (totaling 435 drilling permits) in Pennsylvania visible in 2008 aerial imagery from the National Agriculture Imagery Program. The ground excavated for wells and associated infrastructure is the most obvious spatial impact.



For each well site, the area for the well pad, new or expanded roads, gathering pipelines, and water impoundments were digitized and measured.

Aerial photos before and after development of a Marcellus gas well pad site in Susquehanna County, PA. To assess the impacts of this type of energy development, we have digitized the spatial footprint of 376 gas well pad sites and associated infrastructure.

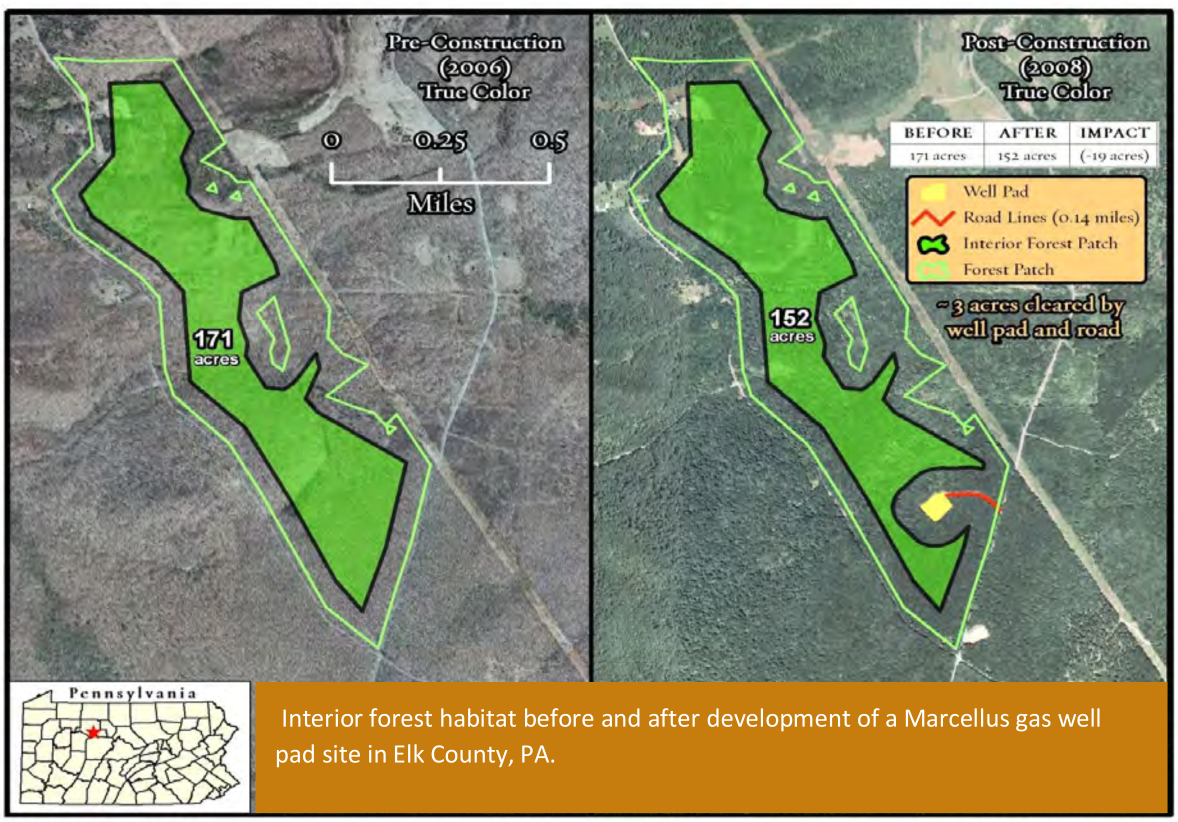
Average Spatial Disturbance for Marcellus Shale Well Pads in Forested Context (acres)		
Forest cleared for Marcellus Shale well pad	**3.1**	**8.8**
Forest cleared for associated infrastructure (roads, pipelines, water impoundments, etc.)	**5.7**	
Indirect forest impact from new edges	**21.2**	
TOTAL DIRECT AND INDIRECT IMPACTS	**30**	

Well pads occupy 3.1 acres on average while the associated infrastructure (roads, water impoundments, pipelines) takes up an additional 5.7 acres, or a total of nearly 9 acres per well pad.

Adjacent lands can also be impacted, even if they are not directly cleared. This is most notable in forest settings where clearings fragment contiguous forest patches, create new edges, and change habitat conditions for sensitive wildlife and plant species that depend on "interior" forest conditions.

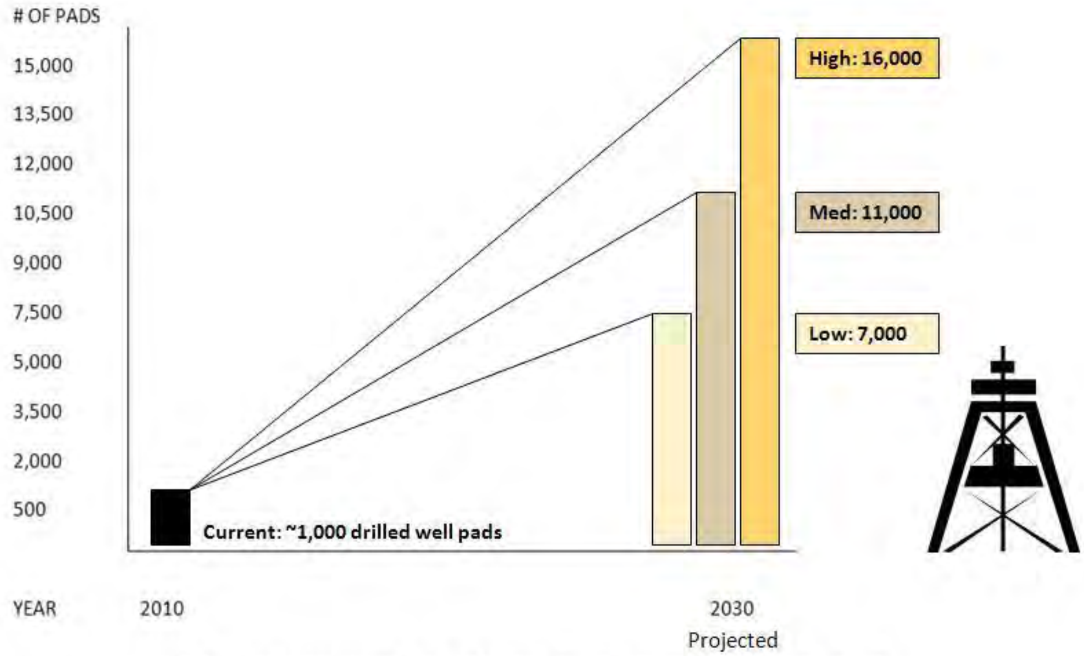
Forest ecologists call this the "edge effect." While the effect is somewhat different for each species, research has shown measurable impacts often extend at least 330 feet (100 meters) forest adjacent to an edge. Interior forest species avoid edges for different reasons. Black-throated blue warblers and other interior forest nesting birds, for example, avoid areas near edges because of the increased risk of predation. Tree frogs, flying squirrels and certain woodland flowers are sensitive to forest fragmentation because of changes in canopy cover, humidity and light levels. Some species, especially common species such as whitetail deer and cowbirds, are attracted to forest edges – often resulting in increased competition, predation, parasitism, and herbivory. Invasive plant species, such as tree of heaven, stilt grass, and Japanese barberry, often thrive on forest edges and can displace native forest species. As large forest patches become progressively cut into smaller patches, populations of forest interior species decline.

To assess the potential interior forest habitat impact, we created a 100 meter buffer into forest patches from new edges created by well pad and associated infrastructure development. For those well sites developed in forest areas or along forest edges (about half of assessed sites), an average of 21 acres of interior forest habitat was lost.



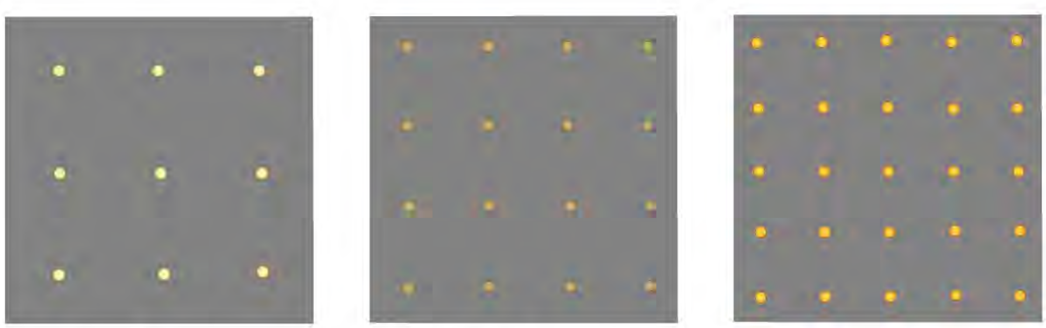
Interior forest habitat before and after development of a Marcellus gas well pad site in Elk County, PA.

The number of Marcellus wells drilled in Pennsylvania during the next two decades will expand steadily. Just how many wells are drilled will be driven by various factors including natural gas prices, technological improvements, human resources, regulatory changes in Pennsylvania and beyond (e.g., end of New York drilling moratorium), and social preferences. Assessing how these factors will change over the next two decades is very difficult; therefore our projections assume economic, policy, and social conditions remain stable enough to promote steady expansion of Marcellus gas development in the state. The first key variable in our projection is the number of drilling rigs that will be operating in Pennsylvania. By October 2010, the industry had moved just over 100 rigs into Pennsylvania to drill Marcellus wells according to the Baker-Hughes weekly rig count. Given the high productivity of the Marcellus and its proximity to major northeastern markets, most industry observers expect this number to continue growing steadily. The number of horizontal drill rigs operating in the Barnett Shale has peaked at about 200, but the



Key drivers: number of rigs, number of wells per pad.

We project 60,000 Marcellus wells will be drilled during the next twenty years based on company investor presentations and academic assessments of gas development potential. Depending on how many wells on average are placed on the same pad site (see illustration below), we project between 7,000 and 16,000 new well pad sites will be developed in Pennsylvania by 2030.



Low Scenario	Medium Scenario	High Scenario
10 wells per pad	6 wells per pad	4 wells per pad
Pads spaced ~5,200 ft apart	Pads spaced ~4,100 ft apart	Pads spaced ~3,350 ft apart

Marcellus Shale is much larger and could reach 300 rigs in Pennsylvania alone. We chose a conservative estimate of 250 maximum horizontal drill rigs for each scale projection scenario. Assuming that each rig can drill one well per month, 3,000 wells are estimated to be drilled annually. At that rate, 60,000 new wells would be drilled by the year 2030.

The second key variable, especially for determining land-use and habitat impacts, is the number of wells on each pad. Because each horizontal well can drain gas from 80 to 170 acres (depending on the lateral well length), more wells per pad translates to less disturbance and infrastructure on the landscape. It's technically possible to put a dozen or more Marcellus wells on one pad So far, the average in Pennsylvania is two wells per pad as companies quickly move on to drill other leases to test productivity and to secure as many potentially productive leases as possible (leases typically expire after 5 years if there is no drilling activity). In many cases, the gas company will return to these pads later and drill additional wells. The low scenario (6,000 well pads) assumes that each pad on average will have ten wells. Because many leases are irregularly shaped, in mixed ownership, or the topography and geology impose constraints, it is unlikely this scenario will develop. It would take relatively consolidated leaseholds and few logistical constraints for this scenario to occur. The medium scenario for well pads assumes 6 wells on average will be drilled from each pad, or 10,000 well pads across the state. Industry staff generally agree that six is the most likely number of wells they will be developing per pad for most of their leaseholds, at least where lease patterns facilitate drilling units of 600 acres or larger. The high scenario assumes each pad will have 4 wells drilled on average, or 15,000 well pads across the state. This scenario is more likely if there is relatively little consolidation of lease holds between companies in the next several years.

The number of well pads is less important than where they are located, at least from a habitat conservation perspective. To understand which areas within Pennsylvania's Marcellus formation are more and less likely to be developed, we used a machine-based learning modeling approach known as maximum entropy (Maxent 3.3.3a, Princeton University). Maximum entropy was used to find relationships between 1,461 existing and permitted well pad locations and variables that might be relevant to a company's decision to drill a Marcellus well. Such variables were chosen based on data availability and included Marcellus Shale depth, thickness and thermal maturity as well as percent slope, distance to pipelines, and distance to roads. The model produces a raster surface that represents the probability of an area to potentially support future gas well development. An additional 487 existing and permitted wells were used to test the validity of the model's probability surface and the model was found to be 80% accurate in predicting existing and permitted wells from randomly sampled undeveloped areas. The resulting probability map indicates wide variation across the Marcellus formation in terms of the likelihood of future gas well development.

To get a better sense of where gas development is most likely, we searched for the highest probability areas where well pads in each scenario might be located. The probability raster was re-sampled to a resolution that reflects the minimum separation distance between well pads for each of the three impact scenarios (low – 5,217 ft; medium – 4,134 ft; high – 3,346 ft). The minimum separation distance represents the drainage area for gas extraction and is dependent upon the number of wells per pad, which differs among the three impact scenarios. Using this method, each pixel of the raster represents the combined area of a well pad plus the minimum separation distance. The highest probable pixels were then selected until the threshold for each impact scenario was reached (low – 6,000 well pads; medium – 10,000 well pads; high – 15,000 well pads). Areas incompatible for future gas exploration (existing drilled Marcellus Shale wells, Wild and Natural Areas, and water bodies) were excluded from being selected as probable pixels. The highest probable pixels were then converted into points for map display purposes.

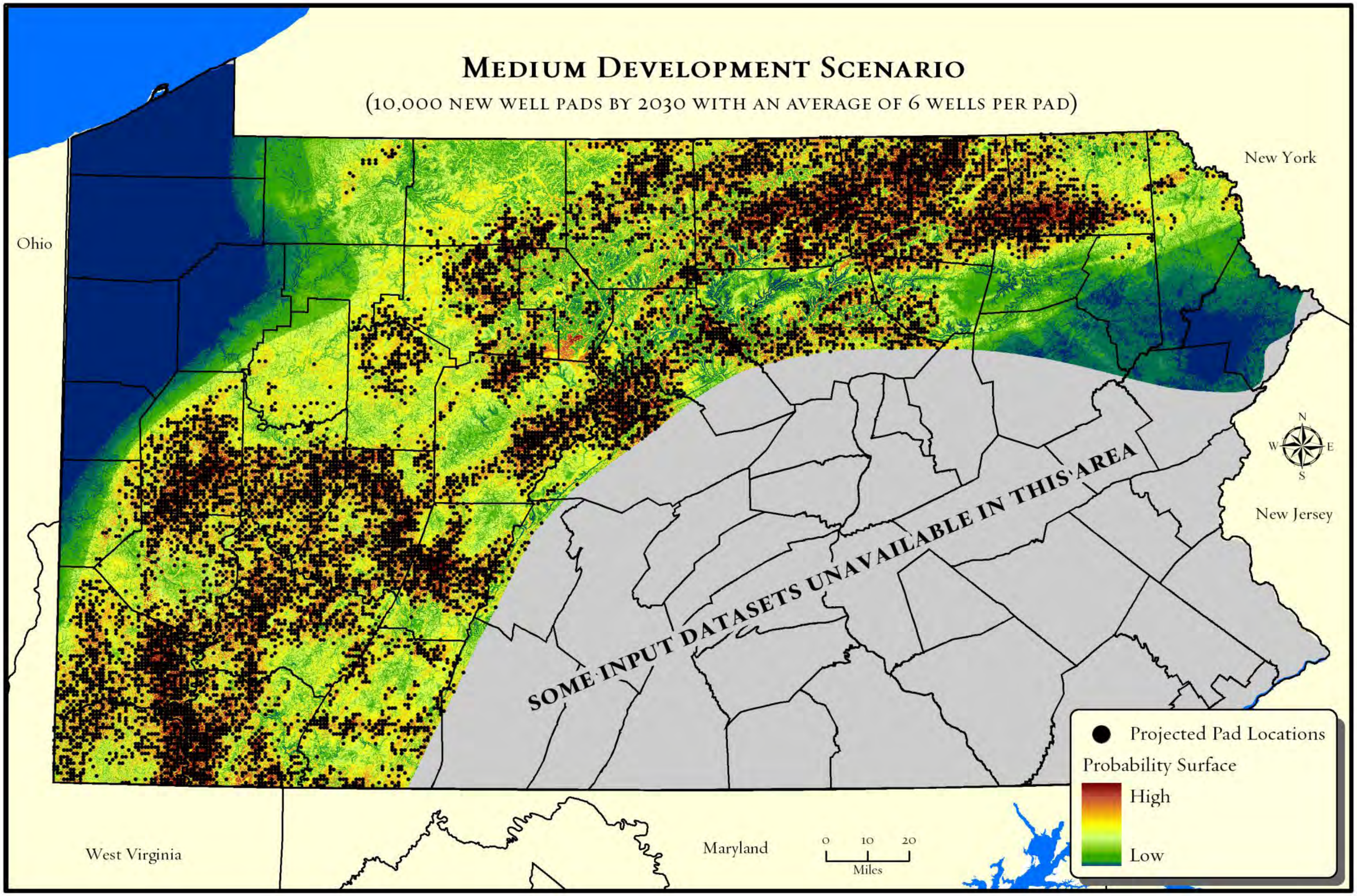
While the geographic area with projected well pads expands from low to high scenarios, the overall geographic pattern is not cumulative due to the differences in minimum separation distance between the three scenarios. Overall, hotspots for future gas development can be seen in half a dozen counties in southwestern Pennsylvania and half a dozen counties in north central and northeastern parts of the state.

These geographic projections of future Marcellus gas development are spatial representations of possible scenarios. They are not predictions. We faced several constraints in developing the geographic scenarios:

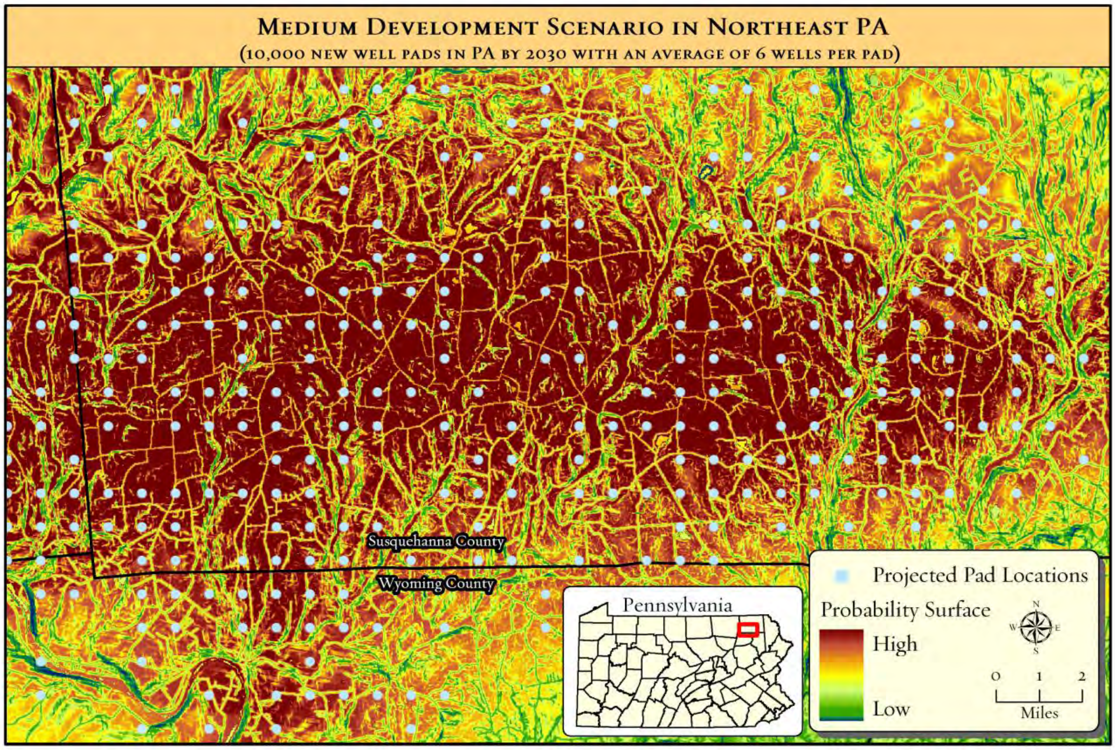
- We do not have access to proprietary seismic and test well geologic data that natural gas companies have. Shale porosity, for example, is a key factor but there are no publicly available data for this.

- We do not have the detailed location of gas company leases. Each company is looking for the highest probability locations across their lease holds while our model looks for the highest probability sites across the entire Marcellus formation in the state. Because there have only been a few Marcellus test wells and permits in the Delaware watershed, we believe the projections for new well pads are probably significantly underestimated in Wayne County.

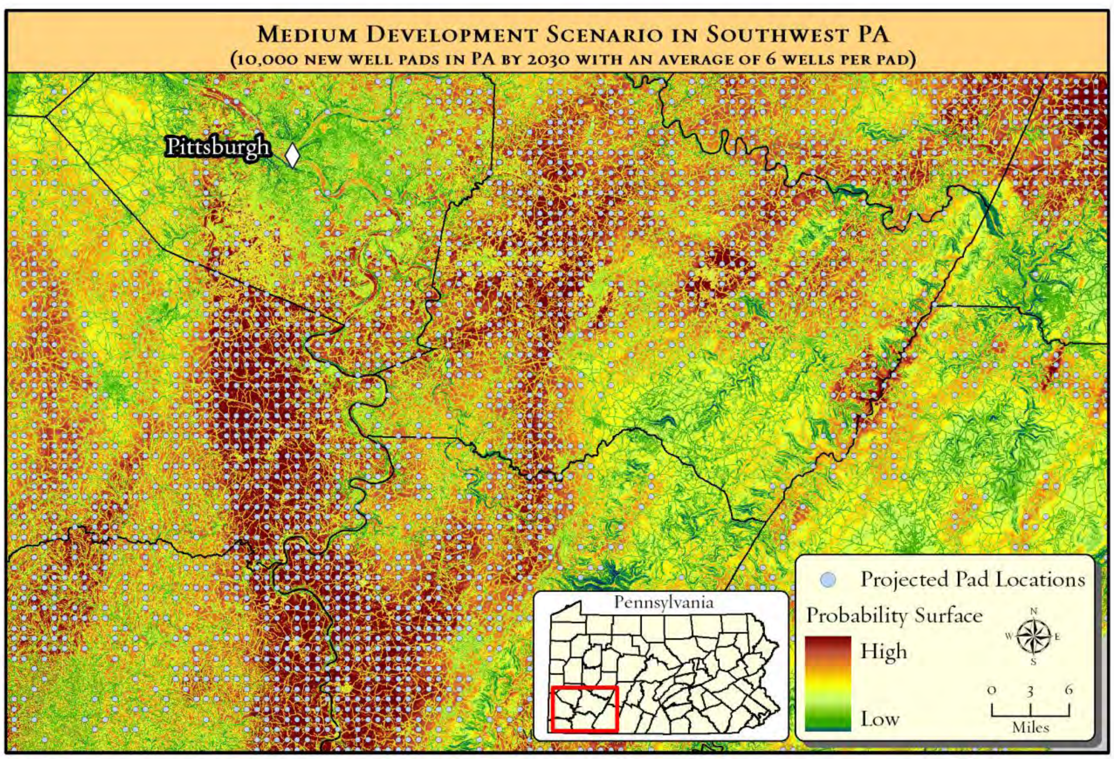
Still, we believe the overall geographic patterns in the projected gas development locations are relatively robust for several reasons. We used nearly 1,500 existing drilled or permitted well pads to build the model and nearly 500 additional drilled and permitted well pads to validate the model. This is typically a sufficient sample size for building predictive models. Additionally, reviews from industry, academic, and government agency reviewers indicate our methods and results are generally sound. Some reviewers expect future well pad locations to be more geographically expansive than our current projections indicate, especially in the Delaware watershed where only a few Marcellus test wells and permits have been issued. Our projections for Wayne County, for example, are likely underestimating future development potential.



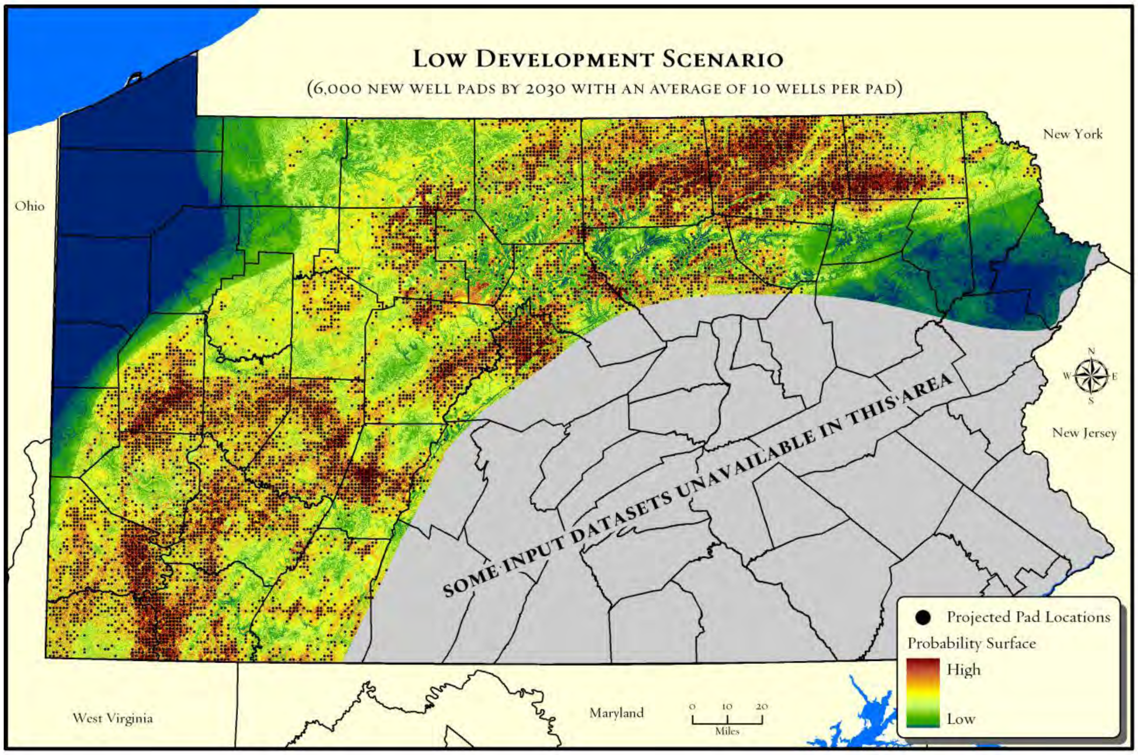
Map showing projected location of 10,000 new Marcellus Shale natural gas pads across Pennsylvania (medium development scenario).



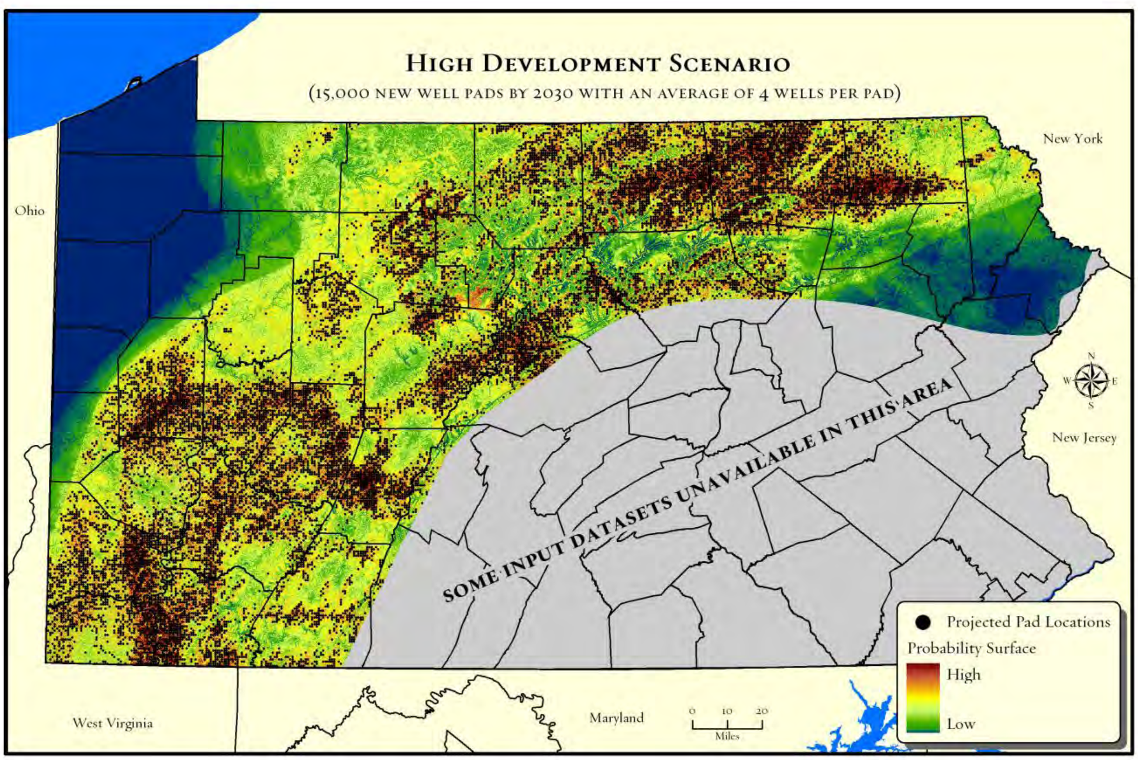
Map showing projected location of new Marcellus well pads in southern Susquehanna County under the medium development scenario.



Map showing projected location of new Marcellus well pads in southwestern Pennsylvania under the medium development scenario.



Map showing projected location of 6,000 new Marcellus well pads across Pennsylvania (low development scenario).



Map showing projected location of 15,000 new Marcellus well pads across Pennsylvania (high development scenario).

Conservation Impacts of Marcellus Shale Natural Gas Development

What is the overlap of the areas with the highest probability of future Marcellus gas development and those areas known to have high conservation values? To answer this question, we intersected the projected Marcellus well pads with areas previously identified and mapped as having high conservation values. We looked at several examples from four categories of conservation value, including:

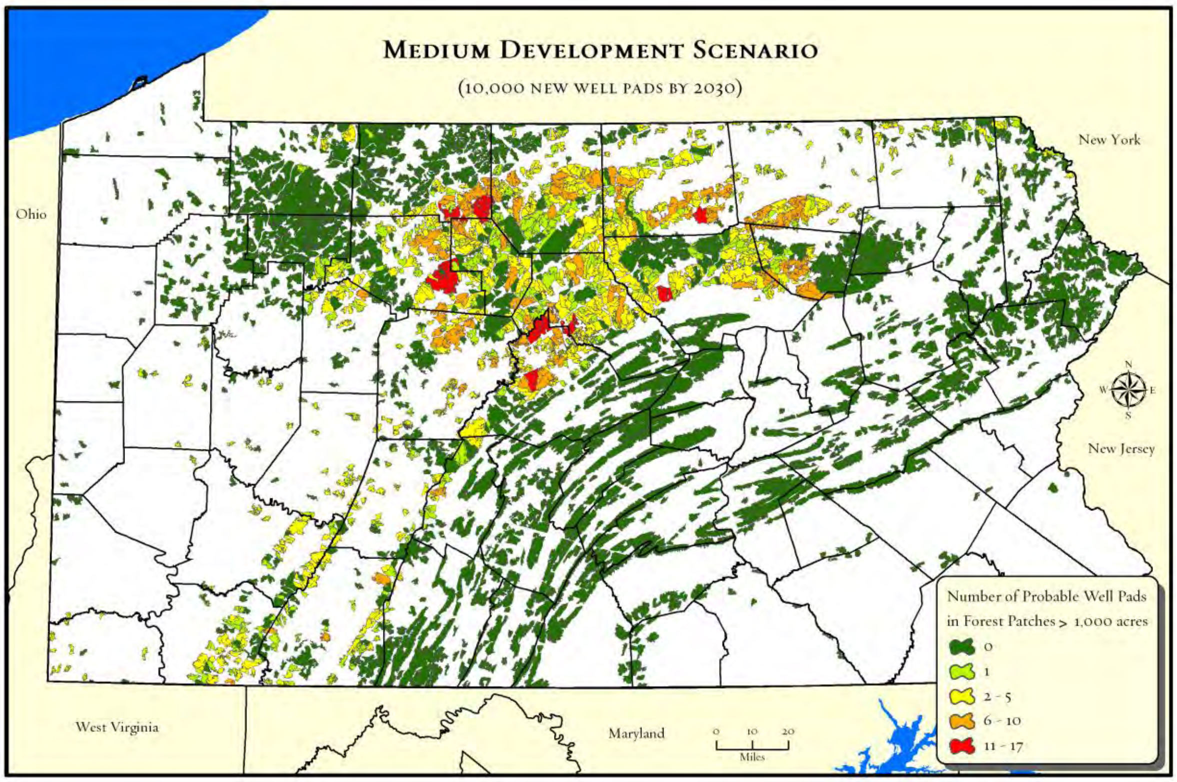
- Forest habitats
- Freshwater habitats
- Species of conservation concern
- Outdoor recreation

Substantial areas of overlap are indicated between likely future Marcellus development areas and Pennsylvania's most important forest, freshwater, sensitive species habitats, and outdoor recreation sites.

FORESTS

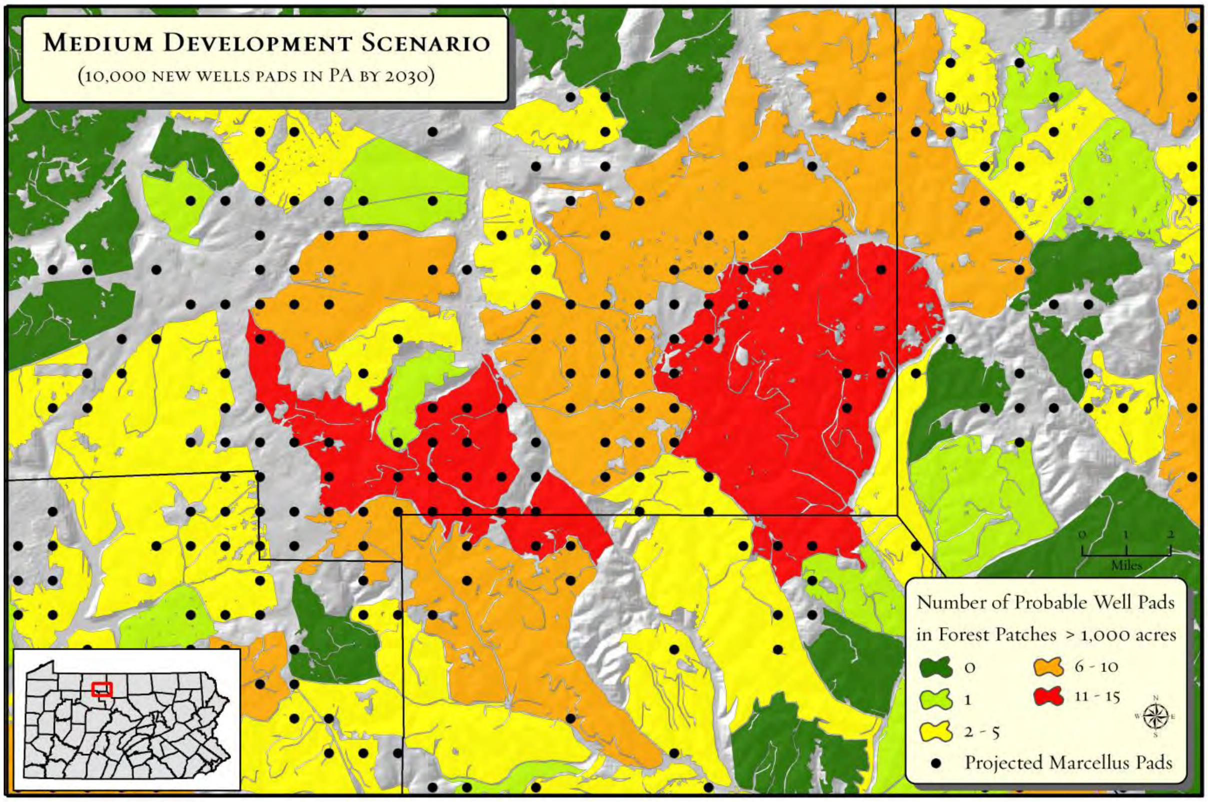
Forests are Pennsylvania's most extensive natural habitat type. Once covering at least 95 percent of the state's land area, forests were whittled away for agriculture, charcoal for iron smelting, and lumber until only a third of the state's forests remained. Forests have rebounded steadily to cover about 60 percent of the state, though a trend toward increasing net loss of forest has emerged during the past decade. Pennsylvania is famous worldwide for its outstanding cherry, oak, and maple hardwoods, and forests provide livelihoods for many thousands of Pennsylvanians in the forest products and tourism industries. They also contribute enormously to the quality of life for all Pennsylvanians by filtering contaminants from water and air, reducing the severity of floods, sequestering carbon dioxide emissions that would otherwise warm the planet, and providing a scenic backdrop to recreational pursuits.

A majority of projected well locations are found in a forest setting for all three scenarios (64% in each case). The low scenario would see 3,845 well pads in forest areas. With an average cleared forest average of 8.8 acres per pad (including roads and other infrastructure), the total forest clearing would be approximately 33,800 acres. Indirect impacts to adjacent forest interior habitats would total an additional 81,500 acres. Forest impacts from the medium scenario (6,350 projected wells in forest locations) would be 56,000 cleared forest acres and an additional 135,000 acres of adjacent forest interior habitat impacts. For the high scenario (9,448 forest well pads), approximately 83,000 acres would be cleared and an additional 200,300 acres of forest interior habitats affected by new adjacent clearings. While the high Marcellus scenario would result in a loss of less than one percent of the state's total forest acreage, areas with intensive Marcellus gas development could see a loss of 2-3 percent of local forest habitats. Some part of the cleared forest area will become reforested after drilling is completed, but there has not been enough time to establish a trend since the Marcellus development started. Large contiguous forest patches are especially valuable because they us sustain wide-ranging forest species, such as northern goshawk and provide more habitat for forest interior species. They are also more resistant to the spread of invasive species, suffer less tree damage from wind and ice storms, and provide more ecosystem services – from carbon storage to water filtration – than small patches. The Nature Conservancy and the Western Pennsylvania Conservancy's Forest Conservation Analysis mapped nearly 25,000 forest patches in the state greater than 100 acres. Patches at least 1,000 acres in size are about a tenth of the total (2,700) and patches at least 5,000 acres are rare (only 316 patches). In contrast to overall forest loss, projected Marcellus gas development scenarios indicate a more pronounced impact on large forest patches. For example, 40 percent of patches greater than 5,000 acres are projected to have at least one well pad and associated infrastructure located in them in the medium scenario



Map showing number of probable Marcellus well pads in forest patches greater than 1,000 acres across Pennsylvania.

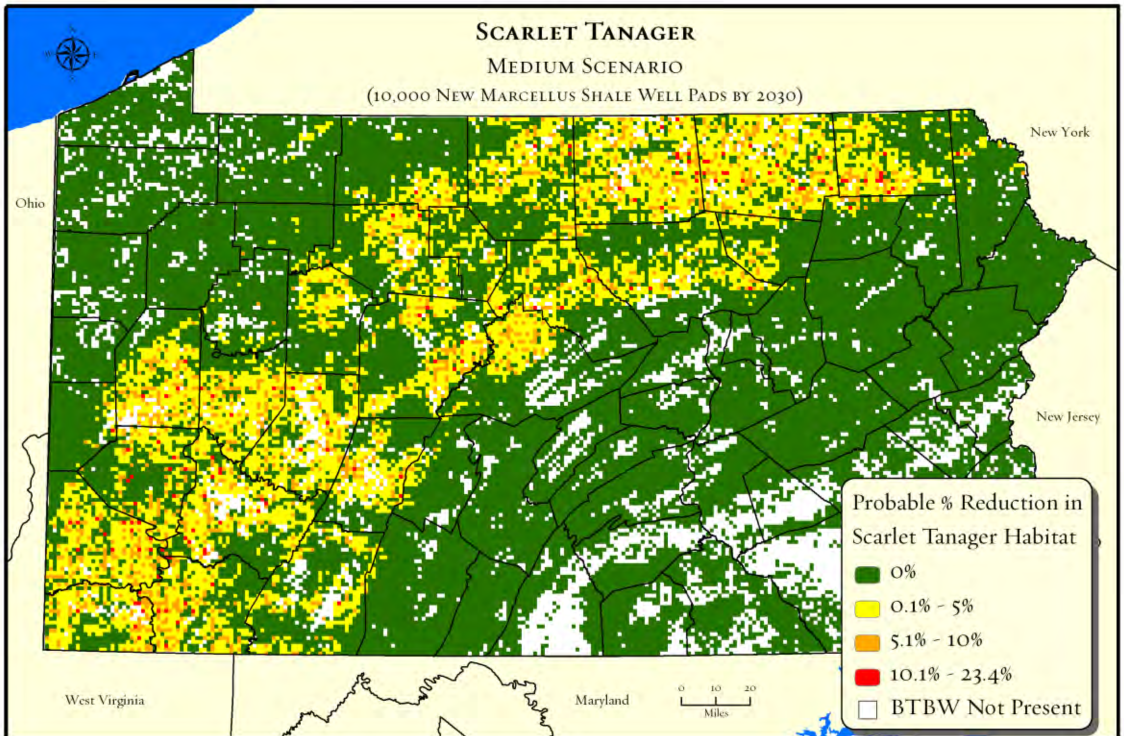
compared to just over 20 percent for patches > 1,000 acres. Most affected large patches have multiple projected well pads (as many as 29). The projections indicate larger patches are likely to be more vulnerable, with over a third projected to have at least one new well pad and road. Many affected large patches have multiple projected well pads (as many as 17 for patches). While one or two well pads and associated infrastructure may not fragment the large patch into smaller patches, each additional well pad increases the likelihood that the large patch will become several smaller patches with a substantially reduced forest interior habitat area.



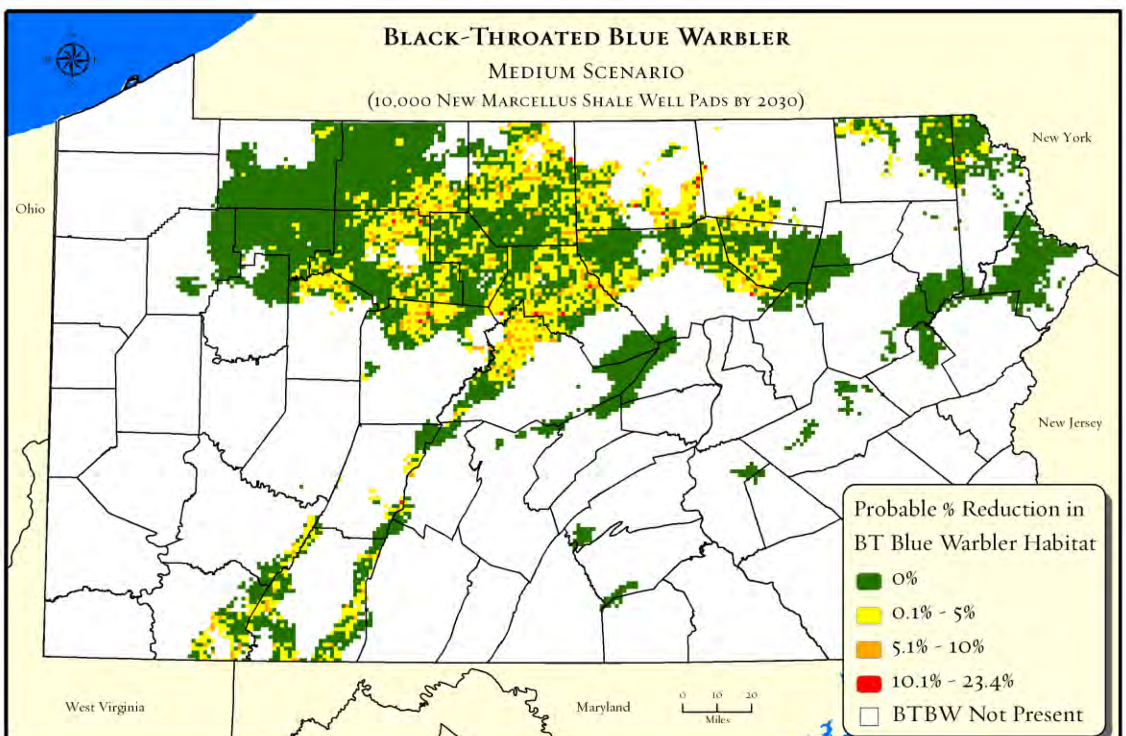
Map showing projected number of well pads in forest patches greater than 1,000 acres under the medium development scenario in Potter, Cameron, McKean and Forest Counties.

Bird species that nest in close canopy forest environments are often referred to as "forest interior" species. The Carnegie Museum of Natural History, Powdermill Nature Reserve and the Pennsylvania Game Commission recently completed Pennsylvania's Second Breeding Bird Atlas project. As part of the project, trained ornithologists conducted point count using standardized protocols at 39,000 sites between 2004-2009. The result is an incredibly detailed data base that provides the most accurate information on the distribution and density of breeding birds available anywhere in the United States. Density data for several forest interior nesting species were mapped and intersected with the projected Marcellus gas well pad locations. The resulting maps show the estimated reduction in habitat for that species in each Marcellus gas probability pixel (including both cleared forest and adjacent edge effects). Scarlet Tanagers are one of the most widespread forest interior nesting bird in the state. Since they are so widespread, a majority of their range in the state is outside of the most likely Marcellus development areas. In some locations, scarlet tanager populations could decline by as much as 23 percent in the Medium Scenario. Black-throated blue warblers are more narrowly distributed in Pennsylvania favoring mature northern hardwood and coniferous forests with a dense understory, frequently in mountain terrain. Since most of their breeding range in Pennsylvania overlaps with likely Marcellus development areas, a higher proportion of their habitat could be affected.

Scarlet tanager © U.S. Fish and Wildlife Service



Map showing estimated percent loss of habitat for Scarlet Tanagers under medium scenario.

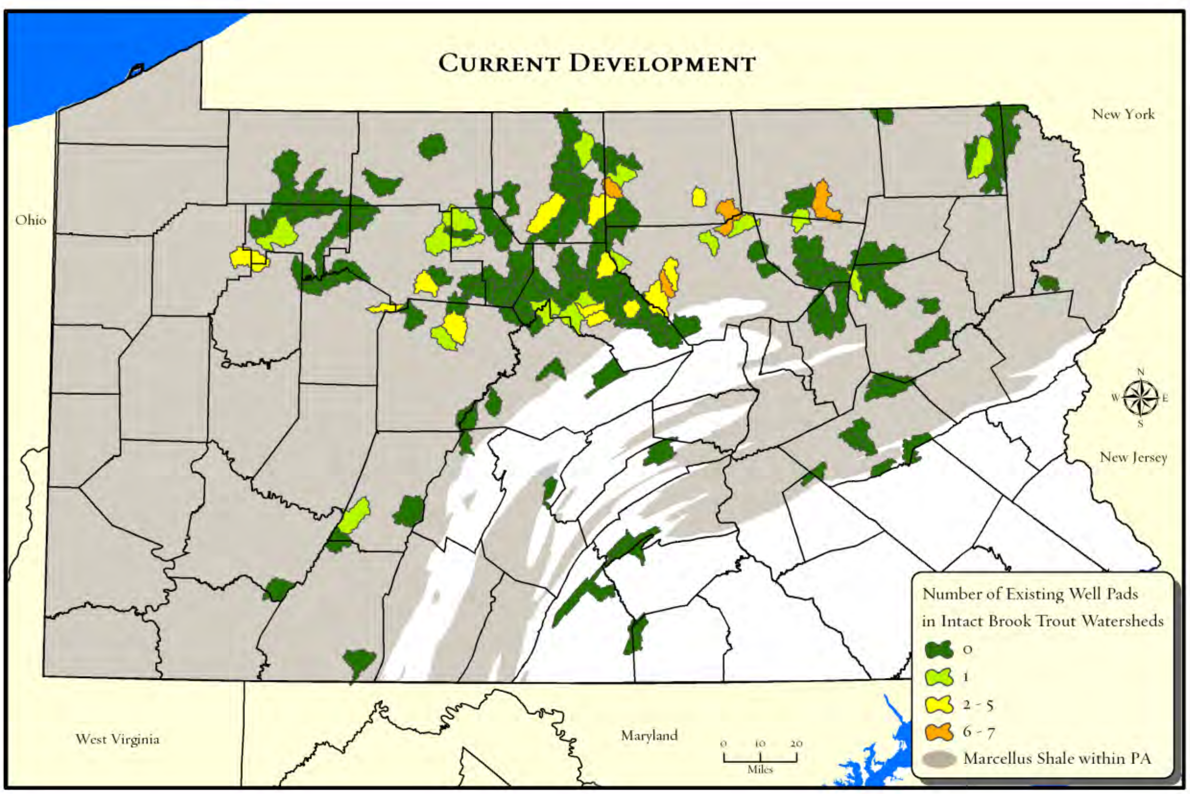


Map showing estimated percent loss of habitat for Black-Throated Blue Warblers under medium scenario.

FRESHWATER

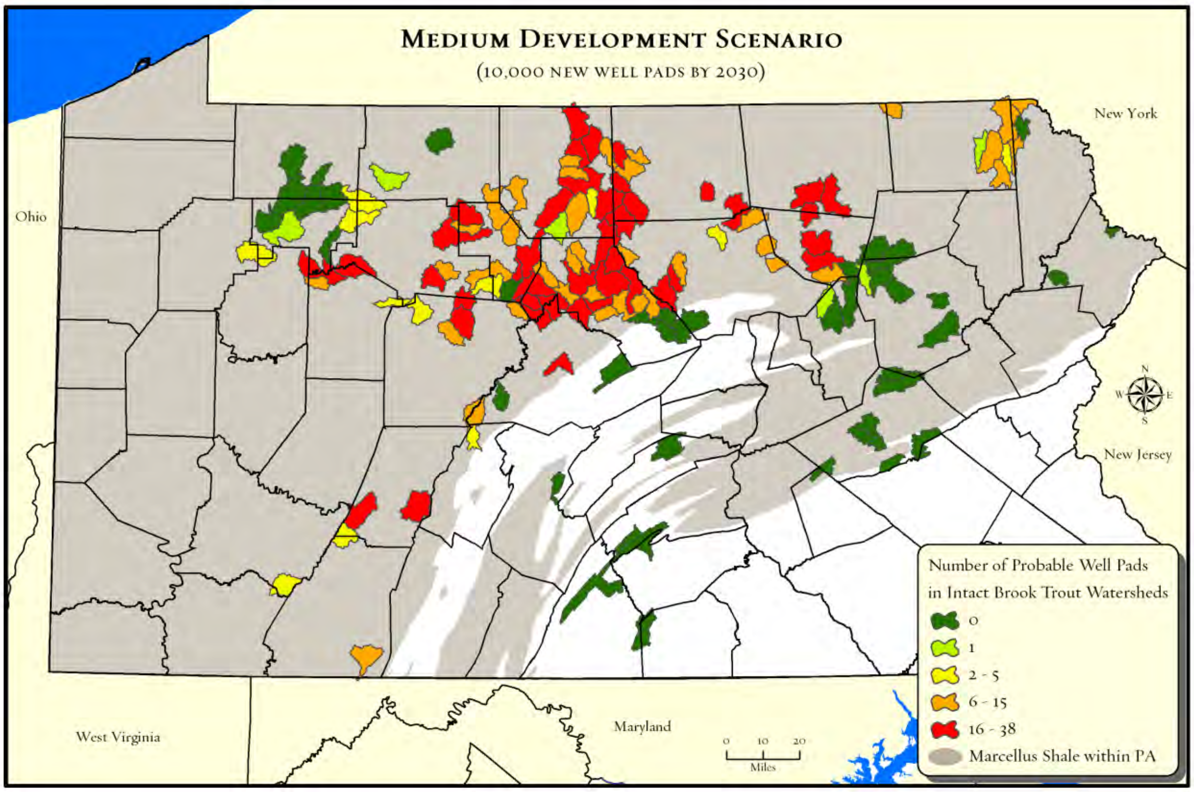
Home to three great river systems and one of the Great Lakes, Pennsylvania's fresh water resources are vital not only to the Commonwealth but to much of the eastern United States. The ***Ohio River*** basin contains the richest fresh water ecosystems in North America. In Pennsylvania, French Creek and parts of the Upper Allegheny River contain some of the most intact aquatic ecosystems in the entire basin. The ***Susquehanna*** **River** is the source of more than half the fresh water that enters the Chesapeake Bay, and most of the water that flows down the Susquehanna River originates in tributary headwaters across a wide swath of central Pennsylvania. Forming Pennsylvania's eastern boundary, the ***Delaware River*** is the longest undammed river in the eastern United States, one of the last strongholds for Atlantic coast migratory fish, and provides the drinking water source for nearly 20 million Americans living in Pennsylvania, New York, and New Jersey. Because of their importance to human health and livelihoods, the potential of Marcellus gas development to affect water flows and quality have received growing attention from regulatory agencies, natural gas companies, and environmental groups.

The intersection of gas development with sensitive watersheds has received less attention. High Quality and Exceptional Value (EV) watersheds have been designated by the Pennsylvania Department of Environmental



Map showing current number of Marcellus well pads in intact and predicted intact brook trout watersheds. Data source: Eastern Brook Trout Joint Venture.

Protection across the state. Our projections indicate 28 percent of High Quality and 5 percent of Exceptional Values streams have or will have Marcellus gas development during the next two decades presence of well pads in these watersheds may not be a problem as long as spill containment measures and erosion and sedimentation regulations are strictly observed and enforced in these areas. More specifically, the projections indicate 3,581 well pads could be located within ½ mile of a High Quality or Exceptional Values streams. Pads within close proximity to High Quality and especially Exceptional Value streams pose more risk than those at greater distances, as there is increased risk for potential spills and uncontained sediments to find their way into streams.



Map showing projected number of Marcellus well pads by 2030 in intact and predicted intact brook trout watersheds under medium scenario. Data source: Eastern Brook Trout Joint Venture.

Native brook trout are one of the most sensitive aquatic species in Pennsylvania watersheds. Brook trout favor cold, highly-oxygenated water and are unusually sensitive to warmer temperatures, sediments, and contaminants. Once widely distributed across Pennsylvania, healthy populations have retreated to a shrinking number of small watersheds. Many of these watersheds overlap with the Marcellus shale formation. A large majority (113) of the 138 intact or predicted intact native brook trout watersheds in Pennsylvania are projected to see at least some Marcellus gas development. Over half (74) are projected to host between 6 – 38 well pads, and the number reaches as high as 64 pads for some intact brook trout watersheds in the high scenario. Rigorous sediment controls and carefully designed stream crossings will be critical for brook trout survival in watersheds, especially upper watersheds, with intensive Marcellus development.

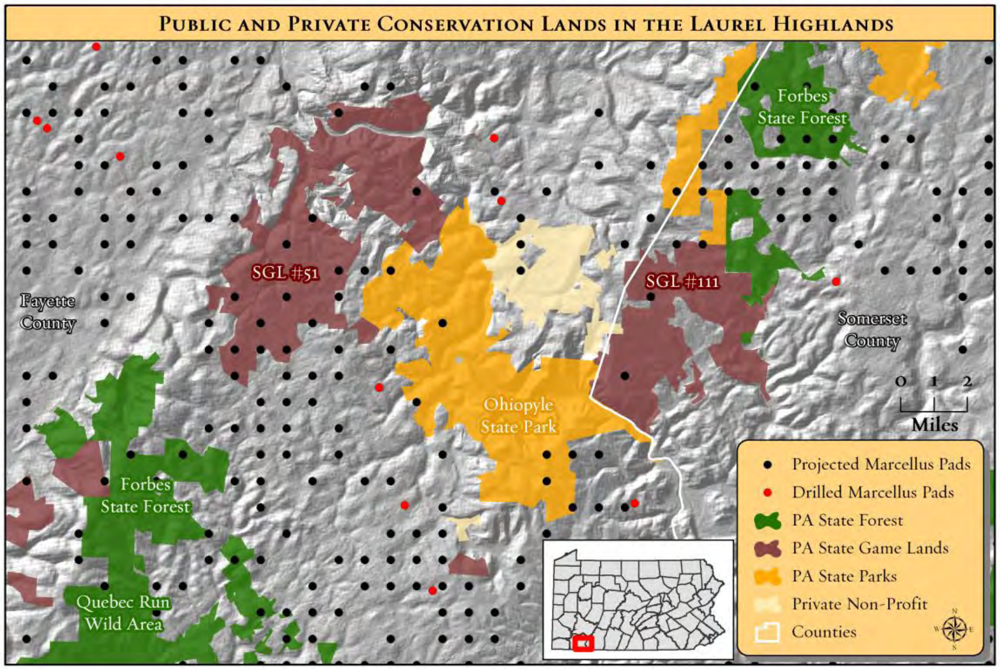
RARE SPECIES

Of the approximately 100,000 species believed to occur in Pennsylvania, just over 1 percent (1052) are tracked by The Pennsylvania Natural Heritage Program (PNHP). Due to low population sizes and immediate threats, these species are rare, declining or otherwise considered to be of conservation concern. PNHP records indicate that 329 tracked species have populations within pixels that have a relatively high modeled probability for Marcellus development. Nearly 40 percent (132) are considered to be globally rare or critically endangered or imperiled in Pennsylvania. Many are found in riparian areas, streams, and wetlands, while others are clustered in unusually biologically diverse areas such as the Youghiogheny Gorge. Some of these species may have only one, two or three populations left in the state. Two examples include the green salamander (*Aniedes aeneus)* with all known populations in relatively high probability Marcellus development pixels and snow trillium (*Trillium nivale*) with 73 percent of known populations in relatively high probability pixels. A well-managed screening system to identify the presence of these species and their preferred habitats will be critical to their survival as energy development expands across the state.

Green salamander © Pennsylvania Fish and Boat Commission

RECREATION

Pennsylvania has built one of the largest networks of public recreation lands in the eastern United States, but much of it could see Marcellus and other natural gas development in coming decades. Of the 4.5 million acres of state and federal lands in the state, we estimate as little as 500,000 acres are permanently protected from surface mineral development, including gas drilling. State and federal agencies do not own mineral rights under at least 2.2 million acres. Most other areas where the state does own mineral rights can be leased, such as the estimated 700,000 acres previously leased for gas development on state forest lands. Severe budget pressures will likely to tempt the legislature to lease additional lands in the future. Our projections excluded state Wild and Natural Areas, National Park lands, and Congressionally-designated Wilderness Areas but otherwise assumed that high probability Marcellus gas pixels on public lands could be developed. The low scenario projects 897 pad locations on State Forest and State Game Lands which expands to 1,438 well pads in the medium scenario and 2,096 pads in the high scenario. The focal area below illustrates what the overlap of future gas development and conservation lands could look like in the medium scenario for the southern Laurel Highlands. It projects 7 well pads in the portion of Forbes State Forest visible in the focal area above, 13 pads on State Game Lands 51, and 3 on State Game Lands 111.



Map showing projected Marcellus well pads under the medium scenario on public and private conservation lands in the Laurel Highlands.

Pennsylvania's state park system, recognized as one of the best in the nation, illustrates the challenge of protecting recreational values in areas of intensive Marcellus development. While the DCNR has a long standing policy of not extracting natural resources in state parks, it does not own the mineral rights under an estimated 80 percent of the system's 283,000 acres. Our projections indicate Marcellus well pads could be located in between 9 and 22 state parks.

AVOIDING FOREST IMPACTS IN THE LAUREL HIGHLANDS

The projected potential impacts of Marcellus gas energy development assume recent patterns of development will continue. Given the relatively large areas drained by Marcellus gas pads (depending on the lateral length and number of wells per pad), there is flexibility in how they are placed. This allows us potentially to optimize between energy production and conservation outcomes. To look at how conservation impacts could be minimized, we examined how projected Marcellus gas pads could be relocated to

Projected Well Pads on State Lands (Medium Scenario)	
DCNR State Forests	**1,002**
DCNR State Parks	**41**
State Game Lands	**436**
Total State Lands	**1,479**

avoid forest patches in the Southern Laurel Highlands in Fayette and Somerset counties. This area is important because it represents a unique ecological region with a large amount of state land as well as private farmland and forest land. The area is also facing great pressure to develop the Marcellus Gas resource. The focus area included approximately 350 square miles and included Chestnut Ridge on its western border and Laurel Ridge on its east. Within the area, there are two state parks (Ohiopyle State Park and Laurel Hill State Park), two State Game Lands (SGL 51, SGL 111), and state forest land (Forbes State Forest).

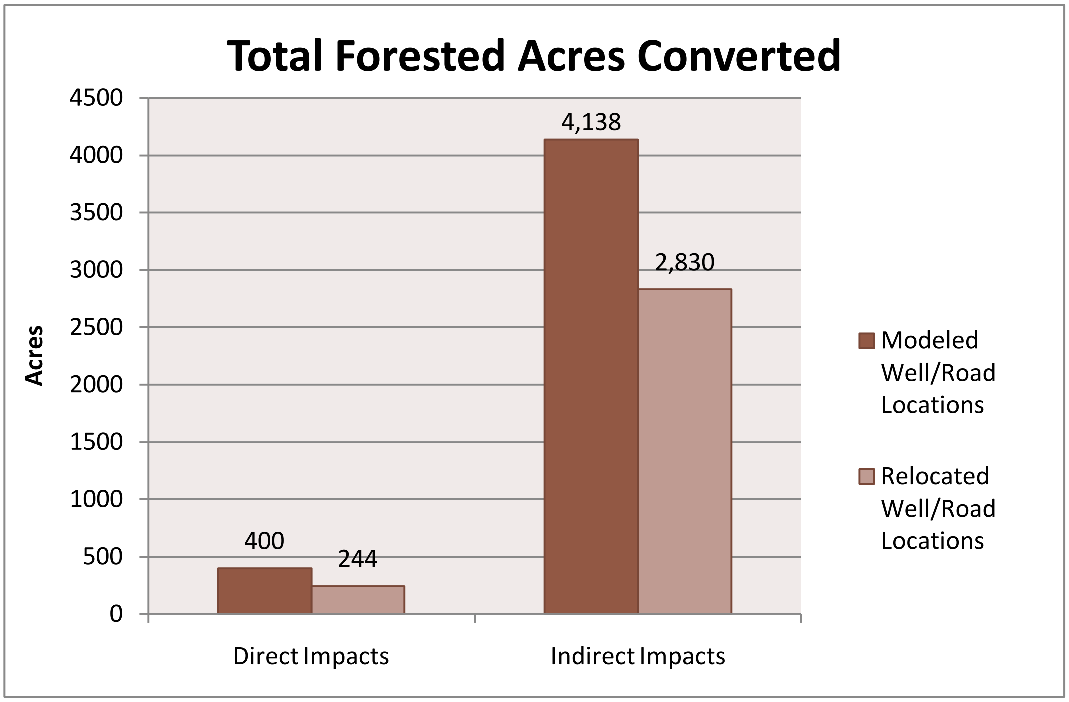
The Medium Scenario projected 127 well pads in the focus area. Fourteen well pads were projected in agricultural fields, 33 were in edge habitat (within 100 m of the forest edge), 11 fell within existing cleared areas (e.g. strip mines), and 69 were in forest. There were five pads on Ohiopyle State Park, and 13 within a mile of its boundary. Laurel Ridge State Park contained two pads. Forbes State Forest had seven modeled pads. State Game Lands 111 had 3 pads, and SGL 51 had 13. It was not clear if DCNR State Parks Bureau or the Game Commission control the sub-surface mineral rights beneath the 23 modeled pads. Given that 80 percent of mineral rights are severed on State Park and State Game Lands (and close to 100 percent in western parts of the state), we have assumed that drilling could happen at those projected locations.

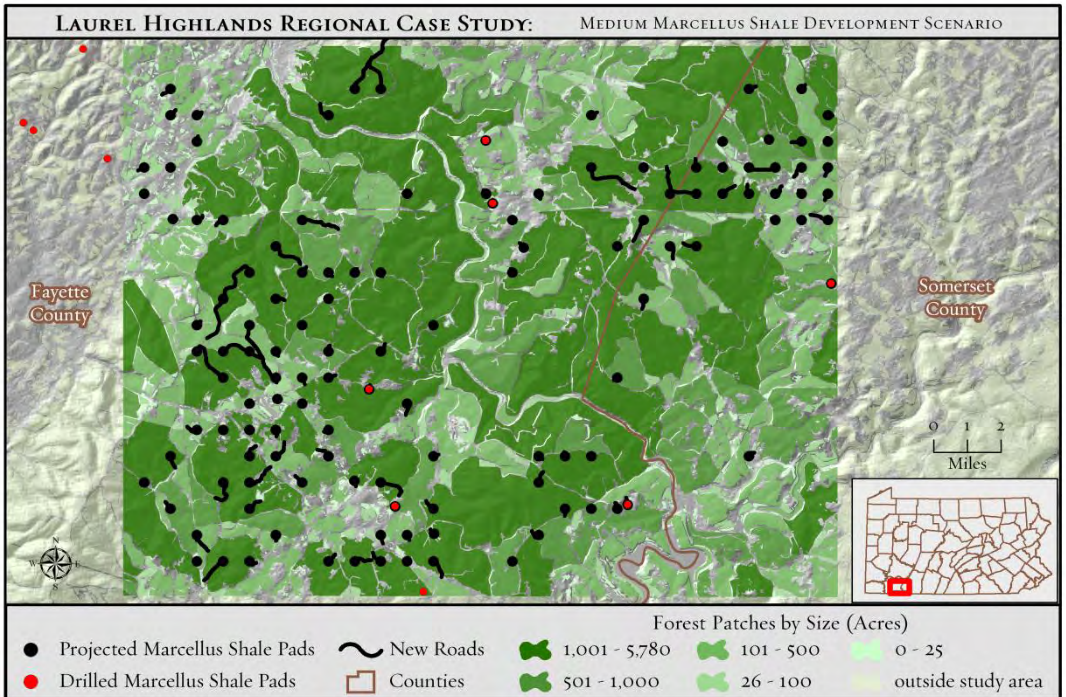
To assess additional impacts beyond the well pad itself, we placed a new and/or improved road from the projected pad to the nearest existing road (ESRI Roads Layer). We placed new roads along existing trails, paths and openings whenever detectable on aerial photo imagery (used Bing Maps and 2005-2006 PA Map imagery), avoiding wetlands, steep slopes, cliffs, rock outcrops, and buildings, and where possible, rivers, streams, and forest patches. The projected pads and roads required clearing 400 acres of forest.

Can a modest shift in the location of well pads reduce impacts to forest patches and conservation lands? To reduce the impacts to forest habitats, the wells were relocated to nearby existing anthropogenic openings, old fields, or agricultural fields. Attempts were made to maintain the 4,200 foot (1,260 m) distance between modeled wells. If nearby open areas did not exist, the locations of the well pads were moved toward the edges of forest patches to minimize impacts to forest interior habitats. A set of rules was developed and followed to minimize bias, including:

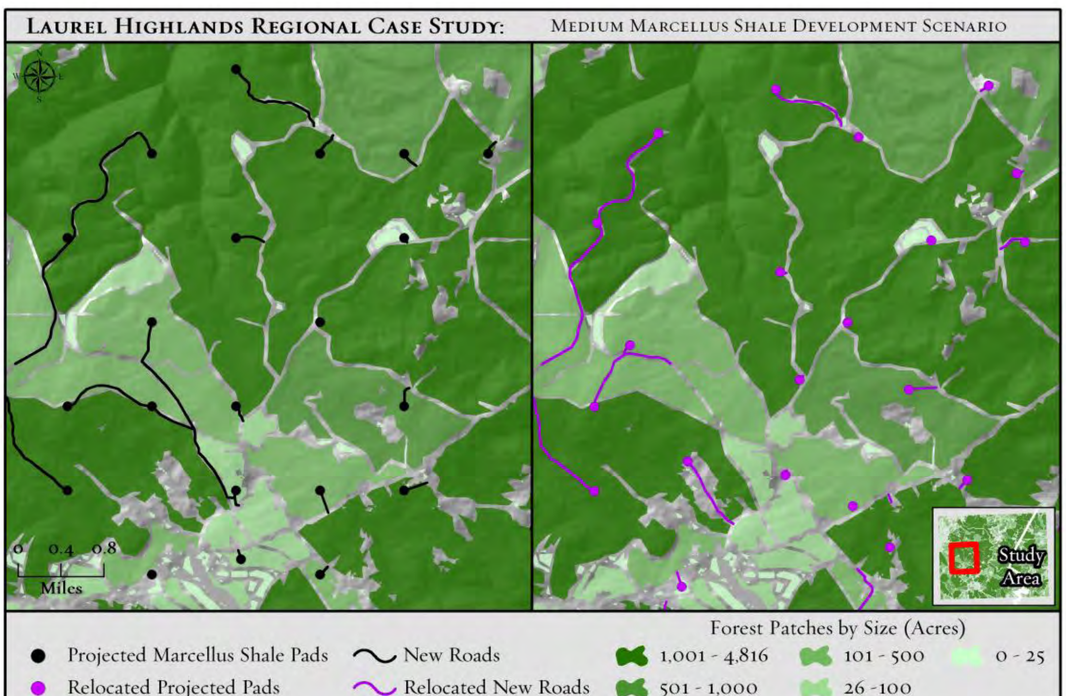
1. Modeled well pads were not relocated if they occurred in old fields or agricultural fields.
2. Modeled well pads that occurred in forest or edge habitat were moved but well pads were placed in the same general areas as the modeled well pad;
3. Attempts were made to avoid placing relocated well pads any closer that the minimum distance between pads, as specified by the medium scenario (1260 m)
4. Agriculture, cleared land (e.g., former strip mines), or otherwise opened land cover was favored over forest or edges for relocating well pads;
5. If the well pad could not be placed in an open area, forest edges were favored over deep interior forest;
6. Residential areas were avoided. Relocated well pads were placed at least 500 feet (150 m) from homes;
7. Wetlands, water, steep slopes, cliffs, rock outcrops, creeks and rivers, buildings and manicured lawns were avoided;
8. Relocated well pads were only placed in areas with similar to those that supported modeled pads.
9. Relocated well pads often were connected to roads using existing trails, paths and openings whenever detectable on aerial photo imagery (used Bing Maps and 2005-2006 PA Map imagery);
10. The same number of relocated well pads were placed on state lands and Western Pennsylvania Conservancy lands as they were in the modeled output;
11. When the modeled well pad occurred within a forest patch with no nearby alternative locations (due to proximity of other wells or environmental constraints), the projected well pad was not relocated.

The relocated wells and roads did not eliminate forest impacts in this heavily forested landscape, but there was a significant reduction. Total forest loss declined almost 40% while impacts to interior forest habitats adjacent to new clearings declined by a third.





Location of 127 projected Marcellus well pads and new roads in the study area in the southern Laurel Highlands.



Relocated well pads (on the right) reduced forest clearing and forest interior habitat impacts by 40 % and 33% respectively compared to the projected well pads (on the left).

Key Findings

Key findings from the Pennsylvania Energy Impacts Assessment for Marcellus Shale natural gas include:

- About 60,000 new Marcellus wells are projected by 2030 in Pennsylvania with a range of 6,000 to 15,000 well pads, depending on the number of wells per pad;

- Wells are likely to be developed in at least 30 counties, with the greatest number concentrated in 15 southwestern, north central, and northeastern counties;

- Nearly two thirds of well pads are projected to be in forest areas, with forest clearing projected to range between 34,000 and 83,000 acres depending on the number of number of well pads that are developed. An additional range of 80,000 to 200,000 acres of forest interior habitat impacts are projected due to new forest edges created by well pads and associated infrastructure (roads, water impoundments);

- On a statewide basis, the projected forest clearing from well pad development would affect less than one percent of the state's forests, but forest clearing and fragmentation could be much more pronounced in areas with intensive Marcellus development;

- Approximately one third of Pennsylvania's largest forest patches (>5,000 acres) are projected to have a range of between 1 and 17 well pads in the medium scenario;

- Impacts on forest interior breeding bird habitats vary with the range and population densities of the species. The widely-distributed scarlet tanager would see relatively modest impacts to its statewide population while black-throated blue warblers, with a Pennsylvania range that largely overlaps with Marcellus development area, could see more significant population impacts;

- Watersheds with healthy eastern brook trout populations substantially overlap with projected Marcellus development sites. The state's watersheds ranked as "intact" by the Eastern Brook Trout Joint Venture are concentrated in north central Pennsylvania, where most of these small watersheds are projected to have between two and three dozen well pads;

- Nearly a third of the species tracked by the Pennsylvania Natural Heritage Program are found in areas projected to have a high probability of Marcellus well development, with 132 considered to be globally rare or critically endangered or imperiled in Pennsylvania. Several of these species have all or most of their known populations in Pennsylvania in high probability Marcellus gas development areas.

- Marcellus gas development is projected to be extensive across Pennsylvania's 4.5 million acres of public lands, including State Parks, State Forests, and State Game Lands. Just over 10 percent of these lands are legally protected from surface development.

- Integration of conservation features into the planning and development of Marcellus gas well fields can significantly reduce impacts. For example, relocating projected wells to open areas or toward the edge of large forest patches in high probability gas development pixels in the southern Laurel Highlands reduces forest clearing by 40 percent and forest interior impacts by over a third.

Additional Information

- Geologic information on the Marcellus shale formation in Pennsylvania: http://www.dcnr.state.pa.us/topogeo/oilandgas/marcellus_shale.aspx

- Estimates of Marcellus shale formation gas reserves: http://geology.com/articles/marcellus-shale.shtml

- Baker-Hughes weekly oil and gas rig count http://gis.bakerhughesdirect.com/Reports/StandardReport.aspx

- Pennsylvania Department of Environmental Protection, Permit and Rig Activity Report: http://www.dep.state.pa.us/dep/deputate/minres/oilgas/RIG10.htm

- Copeland, H. E., K.E. Doherty, D.E. Naugle, A. Pocewicz, and J. M. Kiesecker. 2009. Mapping Oil and Gas Development Potential in the US Intermountain West and Estimating Impacts to Species: http://www.plosone.org/article/info%3Adoi%2F10.1371%2Fjournal.pone.0007400

- Overview of forest fragmentation impacts on forest interior nesting species: http://www.state.nj.us/dep/fgw/neomigr.htm

- Overview of Pennsylvania High Quality and Exceptional Value Streams: http://www.dcnr.state.pa.us/wlhabitat/aquatic/streamdist.aspx

- Pennsylvania Department of Environmental Protection, Chapter 93 Water Quality Standards, Exceptional Value and High Quality Streams: data downloaded from Pennsylvania Spatial Data Access: http://www.pasda.psu.edu

- Eastern Brook Trout Joint Venture intact brook trout watersheds: http://128.118.47.58/EBTJV/ebtjv2.html

- Overview of Carnegie Museum of Natural History, Powdermill Nature Reserve, and the Pennsylvania Game Commission's 2nd Pennsylvania Breeding Bird Atlas Project: http://www.carnegiemnh.org/powdermill/atlas/2pbba.html

- Pennsylvania Natural Heritage Program, including lists of globally rare and state endangered and imperiled species: http://www.naturalheritage.state.pa.us/

- U.S. Department of Agriculture, Natural Resources Conservation Service, National Agriculture Imagery Program: http://datagateway.nrcs.usda.gov/GDGOrder.aspx

- DigitalGlobe, GlobeXplorer, ImageConnect Version 3.1: http://www.digitalglobe.com

Wind

Wind has become one of the country's fastest growing sources of renewable energy. Pennsylvania is a leader in the industry as host to several wind company manufacturing plants and corporate headquarters. Wind energy development has been spurred by its potential to reduce carbon emissions, promote new manufacturing jobs, and increase energy independence. Technological advances have expanded the size and efficiency of wind turbines during the past decade. This, together with state and federal incentive programs, has facilitated wind development in Pennsylvania, which otherwise ranks relatively low among states for its potential wind generation capacity. The eight turbines installed next to the Pennsylvania Turnpike in Somerset County a decade ago have grown to nearly 500 turbines, with more permitted for construction (AWEA, 2010). Topography is a key factor in average wind speeds across Pennsylvania, so nearly all turbines have been built on mountain ridgelines or on top of high elevation plateaus.

Wind energy has become the most symbolic icon of the shift toward a low carbon economy. With no air emissions or water consumption, it is one of the cleanest renewable energy types. Communities across the state benefit economically as rural landowners lease their properties, skilled jobs are created to manufacture turbines, and workers are hired to install and maintain turbines. Wind development has faced controversy in some areas from neighboring landowners and those worried about impacts to migrating birds and bats. The wind industry, government agencies, and independent researchers have invested considerable effort in trying to better understand impacts on birds and bats. For example, 26 wind development companies have signed a cooperative agreement with the Pennsylvania Game Commission to conduct bird, bat and animal surveys using specified protocols in proposed development areas. Among other findings have been the discovery of the Pennsylvania's second largest Indiana bat maternal colony and a variety of previously undocumented foraging and roosting locations for the state's two rarest bats (Indiana and eastern small-footed). Less understood are the potential habitat impacts of wind development in the northeastern United States. This assessment, therefore, focuses on impacts to forest and stream habitats and selected species of conservation concern that may be vulnerable to development of ridgetop habitats.

What is Wind Energy?

Wind mills have powered grain processing and water pumping in agriculture around the world – most famously in the Netherlands – for centuries. The first modern wind facilities to generate electricity were built in California in the early 1980s. Rated at less than 0.5 MW capacity per turbine, the towers were only 50 feet tall. These facilities were poorly designed and generated considerable controversy because they caused significant mortalities to migrating hawks and eagles. Wind energy development did not expand appreciably until the late 1990s when newer turbine designs and federal energy incentives stimulated the development of new facilities. These turbines were rated at 1.0 or 1.5 MW capacity and reached about 200 feet high at the tip of their rotor. Since the power produced by a wind turbine is proportional to the cube of the blade size and how high in the air it is; turbine size, height and power ratings have expanded steadily. The largest turbines installed in Pennsylvania are now rated at

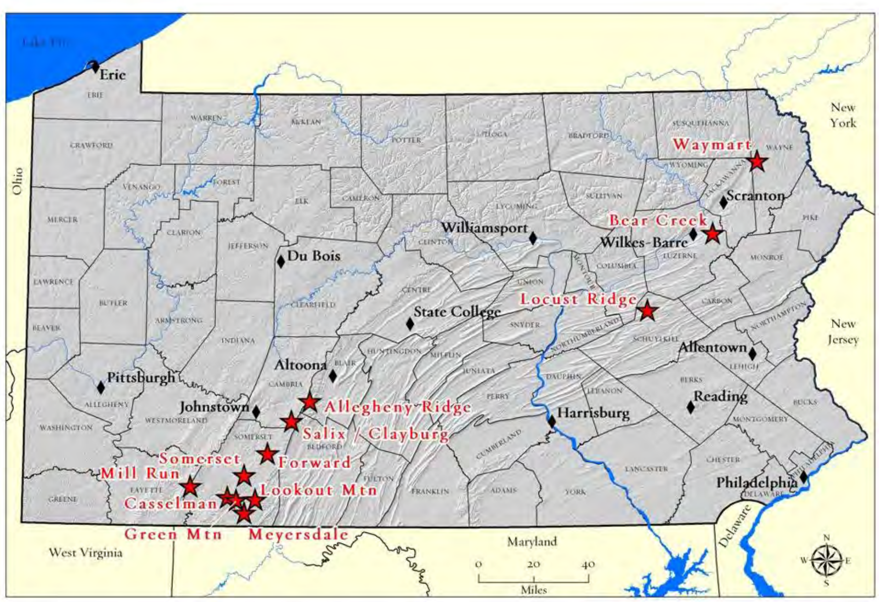
2.5 MW (the average was 1.8 MW in 2009) and reach over 400 feet to the tip of the rotor at the apex of its rotation.

Location is everything for wind development in the northeastern United States. Unlike the vast windswept plains in the Midwest and the intermountain West, high wind speeds in the Northeast are primarily confined to mountain ridgetops, plateau escarpments, and the Atlantic and Great Lake shorelines. Areas that have a wind power class rating of 3 or more (300 watts per m^2) are potentially feasible for wind power development. Wind companies will lease areas that seem to have the most favorable characteristics including wind class, flat pad sites, proximity to transmission lines, and proximity to existing highways. Before development, a wind development company will typically place an anemometer tower on potential development sites to improve knowledge about wind power at the site during a year or longer monitoring period. The turbines are mounted on pads at least 800 feet apart with an access road between towers. The average size of wind facilities has been growing steadily since the first eight were established in 2000. The two largest facilities are now between 75 and 100 turbines.

Several steps have been taken to address potential conflicts between wind development and wildlife in Pennsylvania. The Pennsylvania Game Commission (PGC) has a voluntary agreement in place with most wind companies active in the state to screen proposed facilities for possible impacts to birds and bats and migratory pathways. Participating wind companies carry out pre-construction monitoring for birds and bats. If possible conflicts are identified, PGC works with wind companies to avoid or minimize impacts and to continue monitoring post construction in some cases. Second, the Pennsylvania Wind and Wildlife Collaborative (PWWC) was established in 2005 with a state goal to develop a set of "Pennsylvania-specific principles, policies and best management practices, guidelines and tools to assess risks to habitat and wildlife, and to mitigate for the impact of that development." Several studies on wildlife and habitat issues have been commissioned, though guidelines and Best Management Practices (BMPs) have not been released.

Current and Projected Wind Energy Development

We documented the spatial foot print of 319 wind turbines at 12 wind facilities across the state by comparing aerial photos taken before and after development. Turbine pads, roads, and other new clearings were digitized for all 12 facilities visible in 2008 images from the

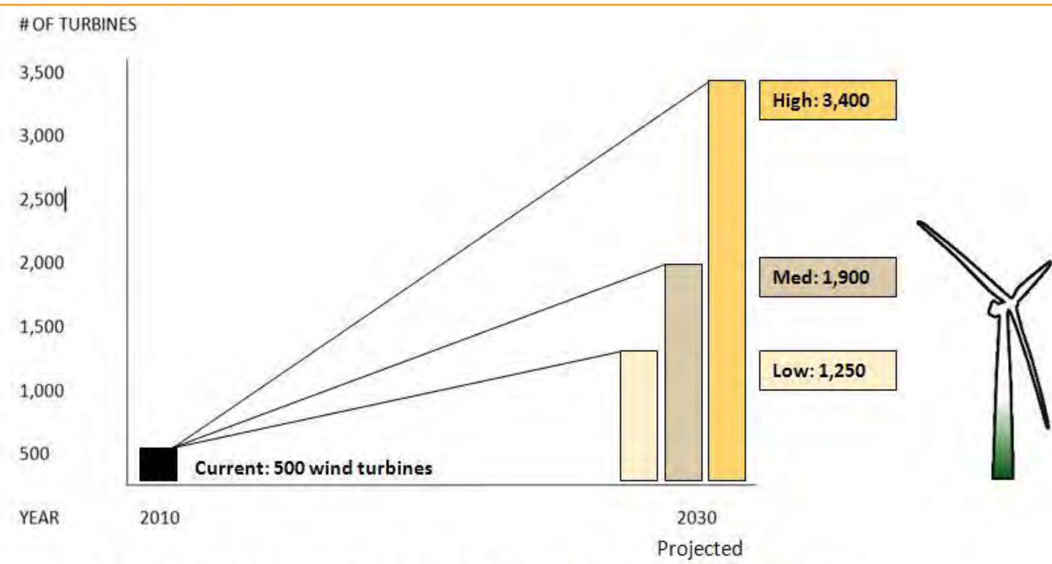


Map showing 12 wind facilities included in the spatial footprint analysis.

National Agriculture Imagery Program. The ground excavated for turbines, roads, and associated infrastructure (e.g., clearings for construction staging areas or electrical sub-stations) is the most obvious spatial impact. For each turbine site, the area for the turbine pad, new roads, staging areas, and sub-stations were digitized and measured. Turbine pads occupy 1.4 acres on average while the associated infrastructure (roads, staging areas and substations) takes up 0.5 acres, or a total of 1.9 acres of spatial impact per wind turbine.

Average Spatial Disturbance for Wind Energy Development in Forested Context (acres)		
Forest cleared for wind turbine	**1.4**	**1.9**
Forest cleared for associated infrastructure (roads, other cleared areas)	**0.5**	
Indirect forest impact from new edges	**13.4**	
TOTAL DIRECT AND INDIRECT IMPACTS	**15.3**	

As with Marcellus gas development, adjacent lands can also be impacted even if they are not directly cleared (See p. 11 for a description of forest edge impacts on forest "interior" species). To assess the potential interior forest habitat impact, we created a 330 foot buffer into forest patches from new edges created by wind turbine and associated infrastructure development. For turbine sites developed in forest areas (about 80% of the 319 turbines), an average area of 13.4 acres of interior forest habitat was lost in addition to the 1.9 acres of directly cleared forest.



Key drivers: Alternative Energy Portfolio Standard (AEPS) and projected contribution of wind to meeting that standard.

We project between 1,250 and 3,400 total wind turbines will be erected in Pennsylvania by 2030.

The number of wind turbines built in Pennsylvania will certainly expand during the next two decades. Various factors will drive exactly how many turbines are ultimately built including electricity prices, state and federal incentives, technological improvements, energy and climate policy, regulatory changes, and social preferences. Our projections assume economic, policy, and social conditions will remain favorable enough to promote steady expansion of wind development in the state since we cannot reasonably forecast energy prices, technological developments, and policy conditions. The key driver in our low scenario is that companies will use wind energy to meet 70 percent of the current Alternative Energy Portfolio Standard (AEPS) Tier 1 standard (8 percent of electric generation). This projection indicates an additional 750 turbines (2 MW average) will be added to the 500 turbines currently operating. The key driver in our medium scenario is that utilities will use wind energy to meet 70 percent of an expanded AEPS 15% Tier 1 standard, as proposed in recent draft legislation. That scenario would add 1,400 new turbines to those already built. The high scenario used in this assessment is based on the 20% wind power electric generation scenario used by the National Renewable Energy Laboratory in the Eastern Wind Integration Study (EWITS). This scenario would require 2,900 additional turbines.

Where are those new turbines in each scenario more and less likely to go? To start, we created a probability surface by looking at a range of variables that might be relevant to a company's decision to develop a wind facility with wind turbines that have already been built. We used the maximum entropy modeling approach used to develop the Marcellus gas probability surface (see p. 13) and built the model using 580 existing and permitted wind turbines. Variables that potentially drive wind energy development were chosen based on data availability and included wind power (W/m^2), distance to transmission lines, percent slope, distance to roads, and land cover. An additional 193 existing and permitted wind turbines were used to test the validity of the model's probability surface and the model was found to be 95.8% accurate in predicting existing and permitted turbines from randomly sampled undeveloped areas. The resulting probability map indicates many long, narrow high probability sites along ridge tops, and several wider areas on high plateaus and along the Lake Erie coastline.

To get a better sense of where wind development is more likely, we searched for the highest probability areas where wind turbine pads in each scenario might be located. The probability raster was re-sampled to 60 meter resolution (0.89 acres) to reflect the actual geographic footprint of wind turbines based on aerial photo assessment. We selected the highest available probability pixel for each scenario and then buffered that pixel by a minimum separation distance of 800 feet (240 meters – the site distance between turbines) between existing turbines before selecting the next highest available probability pixel. The highest probable pixels were then selected until the threshold for each impact scenario was reached (low – 700 turbines; medium – 1,200 turbines; high – 2,700 turbines). Areas incompatible for wind energy development (existing wind turbines, Wild and Natural Areas, and water bodies) were excluded from being selected as probable pixels. The highest probable pixels were then converted into points for map display purposes.

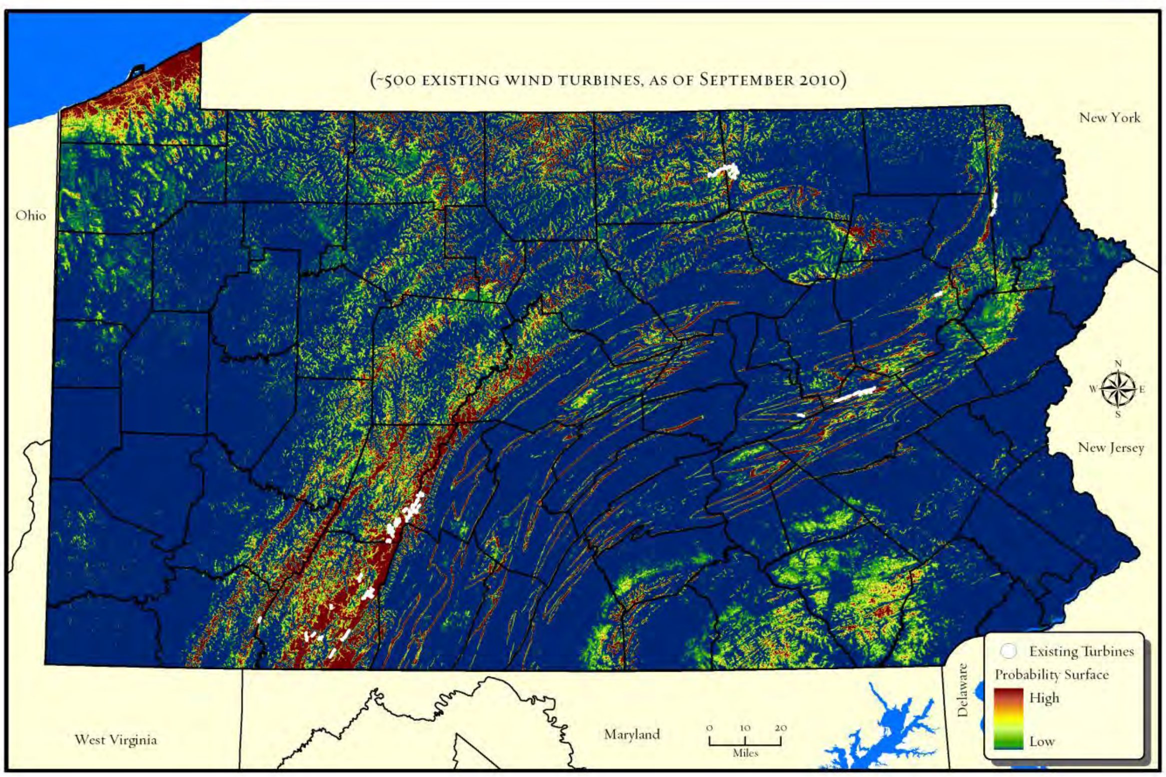
The resulting projected turbine locations occur in strings, groups, and widely scattered single or very small clusters (2-5) of turbines, mostly in southwest, north central and northeastern parts of Pennsylvania.

Wind turbines, however, are almost always located in clusters rather than widely separated locations for individual turbines. In order to represent viable wind farms, we selected clusters of pixels with high probability to represent probable farms based on the results of the model. The following steps were applied to standardize the selection process:

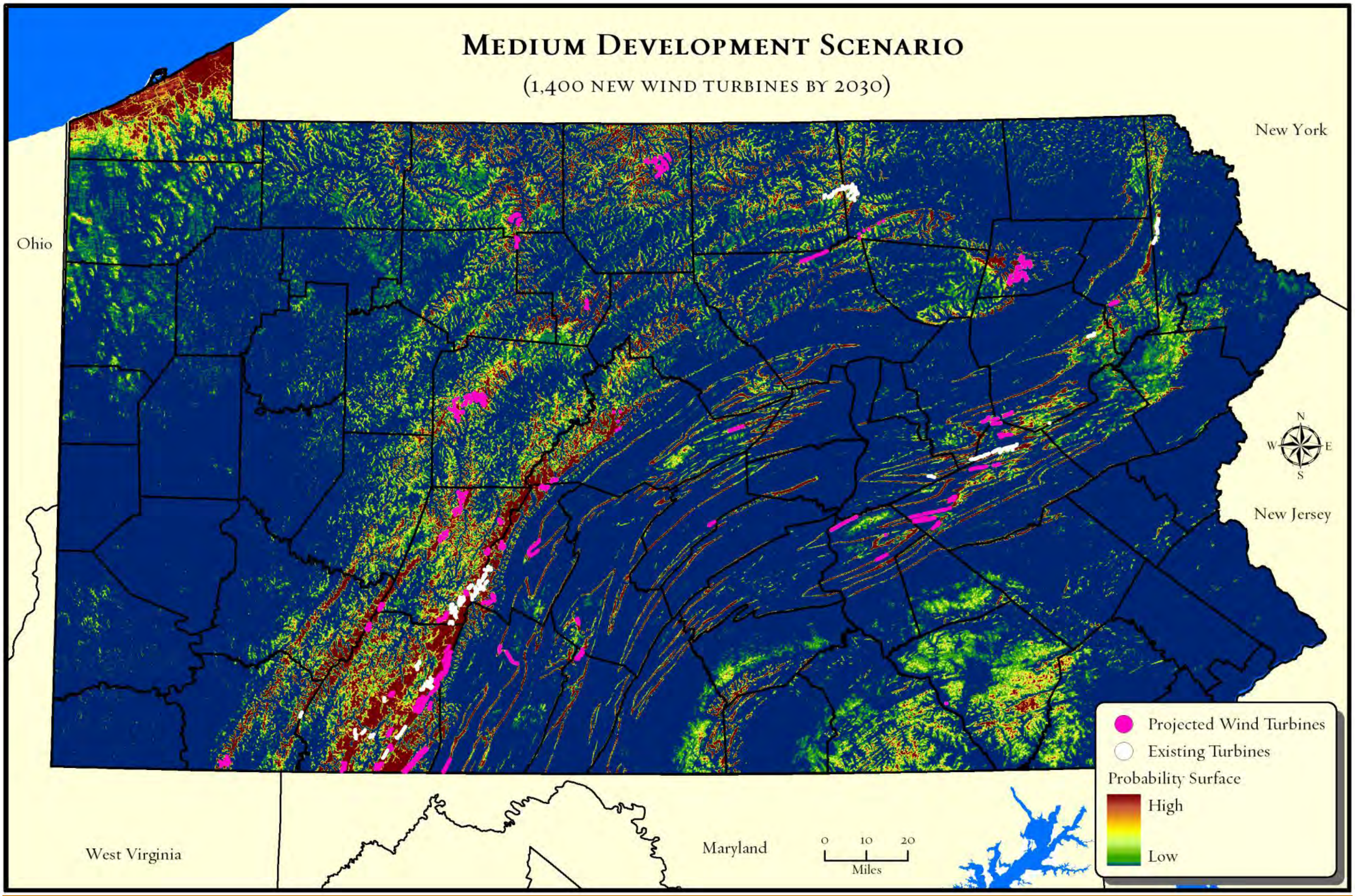
- All selected wind facilities had to be anchored by at least 6 projected wind turbine sites selected by the model

- Buffers of equaling four times the minimum turbine separation distance of 787 ft (totaling 3,148 ft) were applied to existing and permitted wind farms were in order to not ‘expand’ operating and soon to be operating facilities;
- Setbacks of 500 ft from the boundaries of state and federal lands were applied to exclude turbine placement areas adjacent to public land;
- Existing homes Areas (as visible in aerial imagery) were buffered by approximately 1,000 ft;
- Projected clusters (wind farms) were assigned to the low, medium, or high scenario based on the number of the assigned wind turbines to that scenario within the cluster.
- Solitary and very small clusters of wind turbines were relocated to relatively high probability pixels adjacent to projected wind turbine clusters of at least 6 turbines (an 800 feet buffer was applied to each modeled turbine to maintain proper spacing).

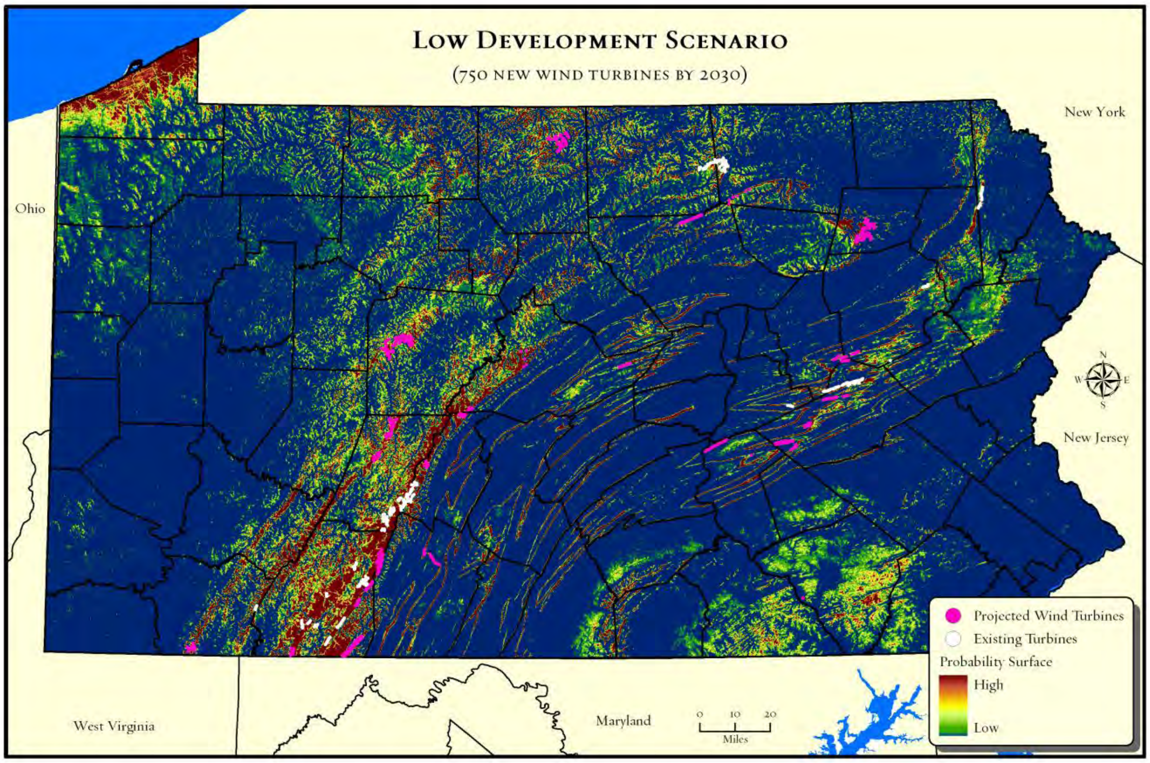
The scenarios are cumulative with the high scenario including the wind facilities for both the low and medium scenarios and the additional turbines needed to meet the high scenario quota.



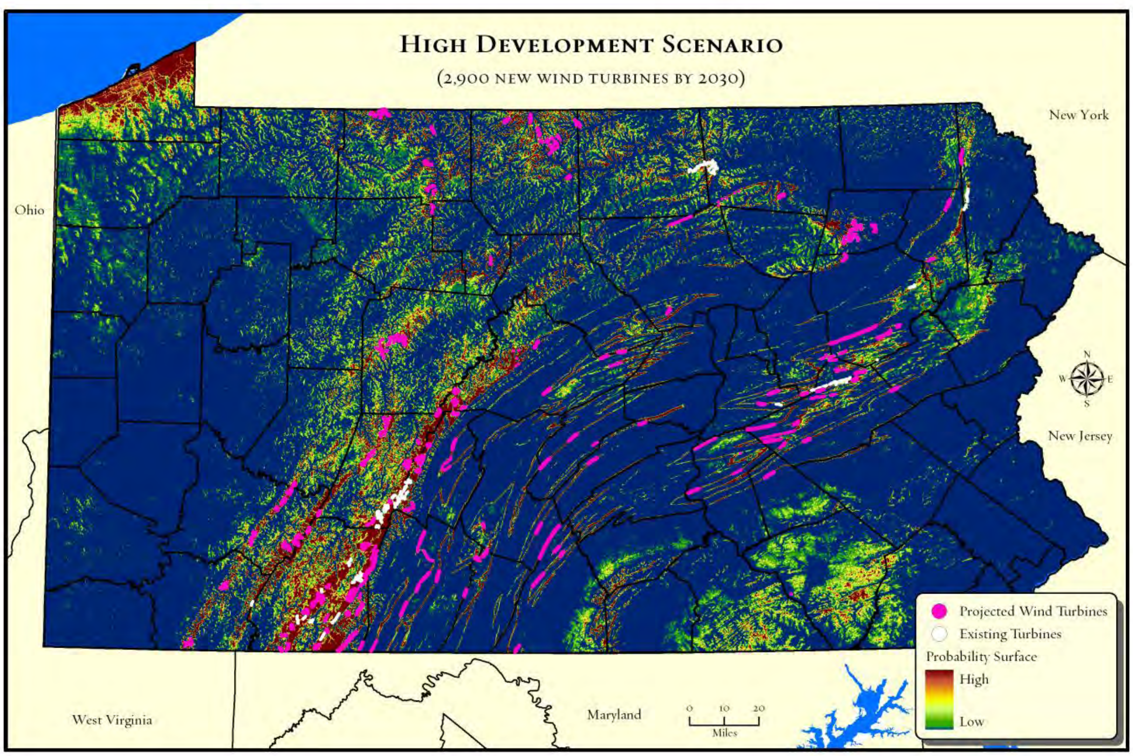
Map showing existing wind turbines with the probability that a given area will be developed indicated by color (dark red is high probability; dark blue is low).



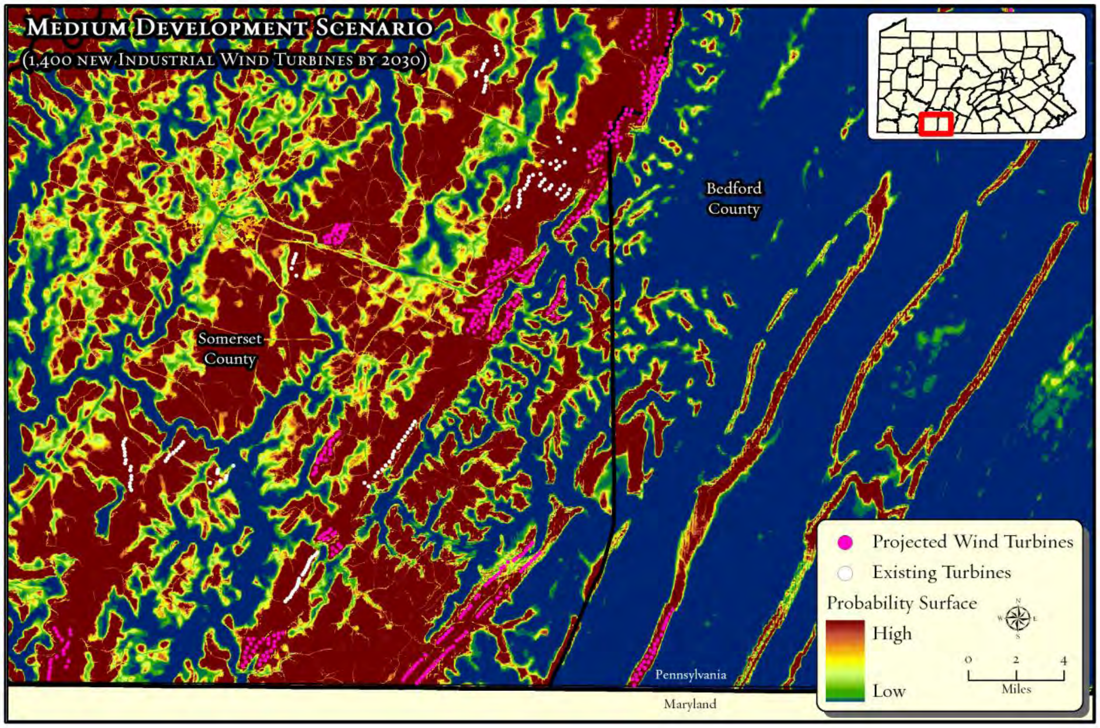
Map showing 1,400 new wind turbines projected by 2030 under the medium development scenario.



Map showing 750 new wind turbines projected by 2030 under the low development scenario.



Map showing 2,900 new wind turbines projected by 2030 under the high development scenario.



Map showing medium wind development scenario within Somerset and Bradford counties.

These geographic projections of future wind energy development are spatial representations of possible scenarios. They are not predictions. We faced several constraints in developing the geographic scenarios:

- We do not have the detailed wind power data that wind companies have developed through anemometer tower monitoring.
- We do not have the detailed location of wind energy leases.

Still, we believe the overall geographic patterns in the projected wind development locations are relatively robust for several reasons. We used over 500 existing or permitted wind turbines to build the model and nearly 200 additional existing and permitted wind turbine sites were used to validate the model. This is typically a sufficient sample size for building predictive models. They are also consistent with Black and Veatch (2010) projected locations for wind facilities under a 15% renewable energy portfolio standard.

Conservation Impacts of Wind Energy Development

What is the overlap of the areas with the highest probability of future wind energy development and those areas known to have high conservation values? To answer this question, we intersected the projected wind energy facilities with high conservation value areas. We looked at several examples from four categories of conservation value, including:

- Forest habitats
- Freshwater habitats

- Species of conservation concern
- Outdoor recreation

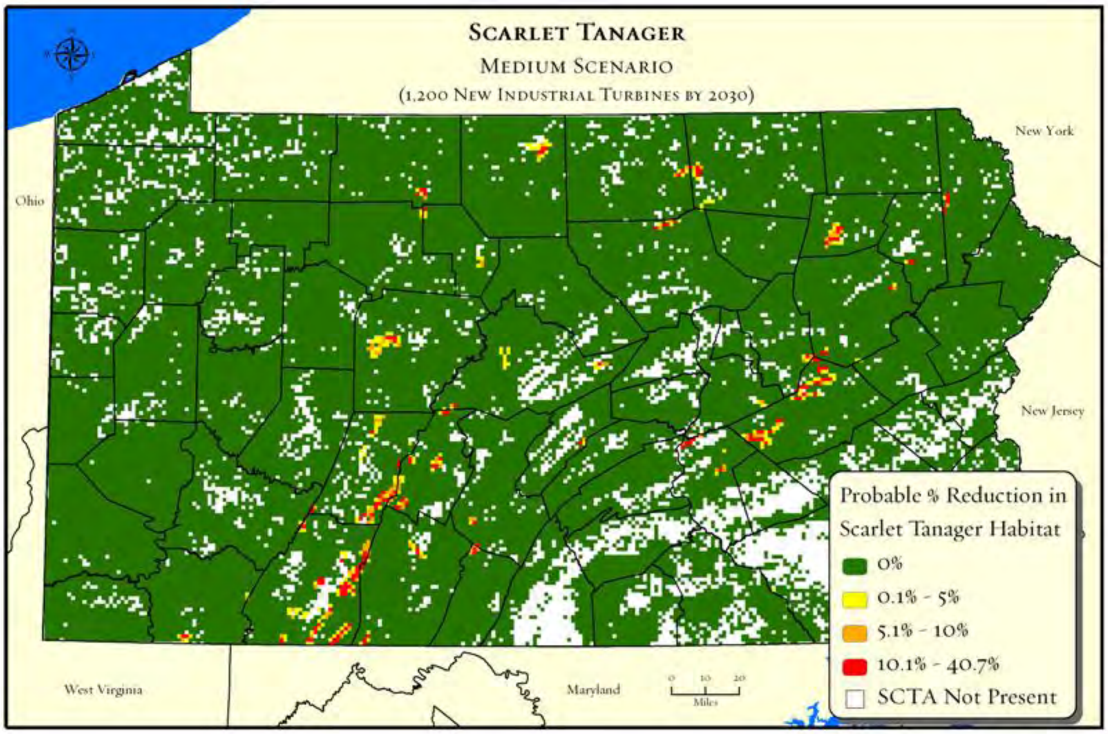
Areas of overlap between likely future wind development areas and priority conservation areas in Pennsylvania are substantially less than the conservation area overlap with likely future Marcellus development areas, largely because the projected foot print will be much smaller.

Forests

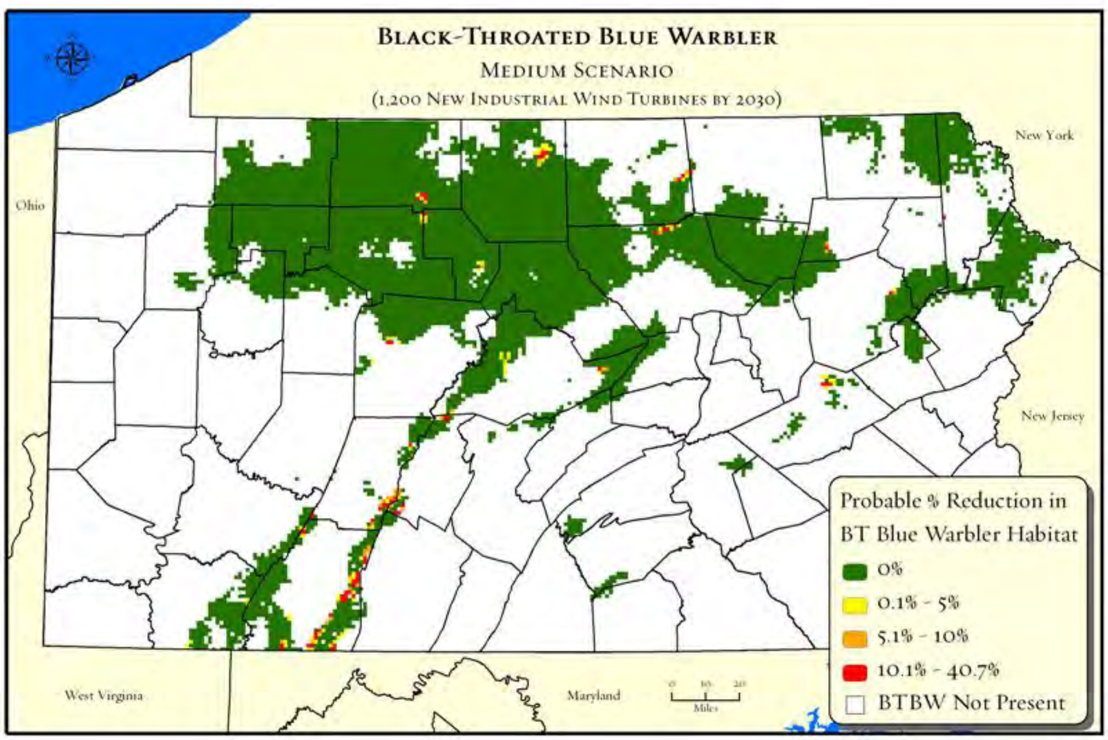
A large majority of projected wind turbines are found in forest patches, about 80 percent for each of the scenarios. The low scenario would see 600 new wind turbines in forest areas. With a cleared forest average of 1.9 acres per turbine (including roads and other infrastructure), the total forest loss would be a modest 1,140 acres. Indirect impacts to adjacent forest interior habitats would total an additional 7,920 acres. Forest impacts from the medium scenario (1,120 projected new turbines in forest locations) would be 2,128 cleared forest acres and an additional 15,840 acres of adjacent forest interior habitat impacts. For the high scenario (2,320 new turbines in forest areas) 4,408 acres would be cleared and an additional 30,624 acres of forest interior habitats would be affected by new adjacent clearings. On a statewide basis, the projected forest losses and accompanying interior forest habitat impacts will be minor given the Pennsylvania's 16 million acres of forest. Locally, these impacts could be significant for individual large forest patches where wind development takes place.

All forests have conservation value, but large contiguous forest patches are especially valuable because they sustain wide-ranging forest species, such as northern goshawk, than small patches. They are also more resistant to the spread of invasive species, can better withstand damage from wind and ice storms, and provide more ecosystem services – from carbon sequestration to water filtration – than small patches. The Nature Conservancy and the Western Pennsylvania Conservancy's Forest Conservation Analysis mapped nearly 25,000 forest patches in the state greater than 100 acres. Patches at least 1,000 acres in size are about a tenth of the total (2,700). The medium projected wind development scenarios indicate 73 patches (3%) greater than 1,000 acres in size are projected to have at least one wind turbine and associated infrastructure. Patches at least 5,000 acres in size are relatively rare (only 316 patches). The medium wind scenario indicates about 21 (7%) of these patches could be affected by future wind turbine development. Most affected large patches have multiple projected wind turbines (as many as 36). Typically, a large patch is split by wind development into two or three smaller patches due the linear pattern of development. Projected gas well pads, by contrast, are more likely to fragment a large patch into multiple smaller patches.

Forest interior bird species could be affected by the clearing of forest and adjacent edge effects that wind turbine facilities create in a forest context. We used data from the 2nd Breeding Bird Atlas Project (see p. 20) to assess the potential impact on forest interior species. The resulting maps show the estimated reduction in habitat for that species in each high wind development gas probability pixel (including both cleared forest and adjacent edge effects). Scarlet Tanagers are perhaps the most widespread forest interior nesting bird in the state. Since they are so widespread, the vast majority of their range in the state is outside of the most likely wind development areas. Scarlet Tanager populations could decline by an insignificant amount due to habitat losses projected in the medium scenario. Black-throated blue warblers are more narrowly distributed in Pennsylvania favoring mature northern hardwood and coniferous forests with a thick understory, frequently in mountain terrain. Likewise, population declines would also be extremely small for Black-throated blue warblers under the medium scenario.



Map showing estimated percent loss of habitat for Scarlet Tanagers under the medium wind scenario.

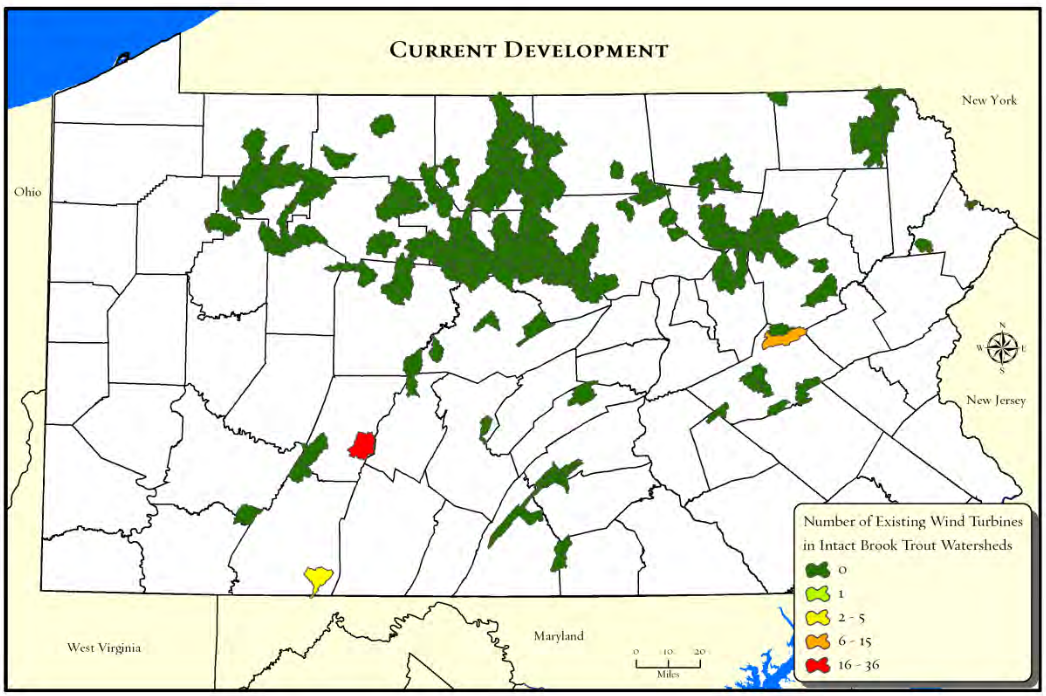


Map showing estimated percent loss of habitat for Black-Throated Blue Warblers under the medium wind scenario.

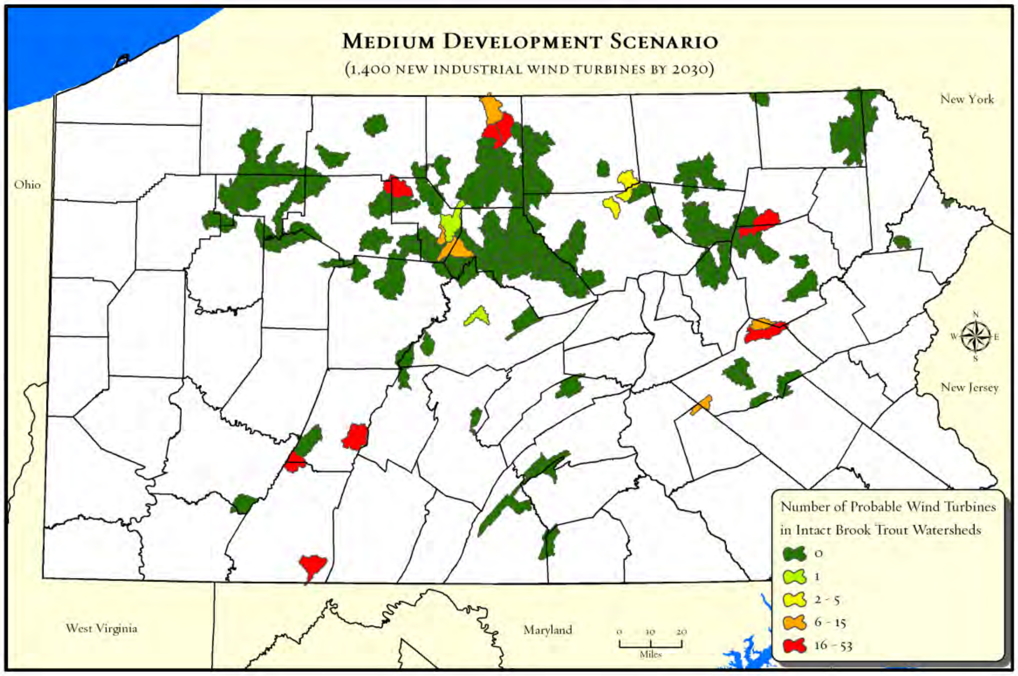
Freshwater

Wind energy and freshwater habitats are not often thought of in the same context since most wind facilities are generally in high elevation areas away from rivers and streams. The exceptions are small headwater streams, some of which may be classified as Exceptional Value watersheds. Our medium scenario projection indicates that 9 percent of future turbine development could be located within ½ mile of an Exceptional Value stream.

Native brook trout are one of the most sensitive species in Pennsylvania watersheds. Brook trout favor cold, highly-oxygenated water and are unusually sensitive to warmer temperatures, sediments, and contaminants. Once widely distributed across Pennsylvania, healthy populations have retreated to a shrinking number of small watersheds. The potential impact on intact brook trout watersheds, however, does increase significantly between the low to high scenarios. Wind turbines have been built in just five of the intact brook trout watersheds identified by the Eastern Brook Trout Joint Venture. That number would expand to 13 in the low scenario, 19 in the medium scenario, and 28 in the high scenario. The presence of wind turbines may pose a limited risk in many of these watersheds, principally from soil disturbance near headwater streams.



Map showing current number of wind turbines in intact and predicted intact brook trout watersheds.



Map showing projected number of wind turbines in intact brook trout watersheds (by 2030) under medium scenario.

Poorly designed or maintained sedimentation measures, especially on road cuts and stream crossings, is the principal risk to these sensitive populations.

Rare Species

Of the approximately 100,000 species believed to occur in Pennsylvania, just over 1 percent is tracked by The Pennsylvania Natural Heritage Program (PNHP). These species are rare, declining or otherwise considered to be of conservation concern. PNHP records indicate that 77 tracked species have populations within pixels that have a relatively high modeled probability for wind development. Most of these species are commonly found in rocky outcrops and scrub oak/pitch pine barrens habitats on ridgetops across the state. Only a handful of species, however, have more than a few occurrences overlapping with the relatively high probability wind development pixels. For example, the eastern timber rattlesnake (*Crotalus horridus*) and Allegheny woodrat (*Neotoma magister*) are strongly associated with rocky outcrops and talus slopes along or near ridgetops. Six percent of the rattlesnake's known rattlesnake breeding/denning sites and three percent of Allegheny woodrat den sites are located in relatively high wind probability pixels. The den sites are very small sites and do not include foraging areas. The Pennsylvania Natural Heritage Program has developed core habitat polygons for each Allegheny woodrat occurrence. Much larger than the den locations, these polygons indicate a much broader overlap – 43 percent – with relatively high probability pixels for wind development. The Northern long-eared Myotis bat (*Myotis septentrionalis*) has about eight percent of its known winter hibernation and summer roosting areas overlapping with relatively high probability wind development pixels. Ridgetop barrens communities in northeastern Pennsylvania have some of the state's largest concentrations of rare terrestrial species. The Nature Conservancy has mapped these communities, and some of these habitats overlap with high wind areas. In general, there appears to be relatively little overlap between tracked species occurrences in Pennsylvania and likely wind development sites. For a handful of species, there is enough overlap to indicate the importance of surveys early in the project planning stage to identify the presence of rare species and their core habitats.

We have not addressed the potential impact of these scenarios on bird migration patterns and bat foraging populations. For more information on wind development impacts on bird and bat species, please see links to the Pennsylvania Game Commission, U.S. Fish and Wildlife Service, American Wind and Wildlife Institute, and Bat Conservation International.

Recreation

Wind development has not occurred on any state or federal lands in Pennsylvania to date. Since our projections assume there will not be a significant change in state land leasing policies for wind development, we have not projected new wind turbines in State Parks, State Forests or State Game Lands. Our projections, however, do indicate that wind turbines will be located in close proximity (sometimes as close as 500 feet) to many state lands. They are likely to be highly visible in some heavily visited areas, such as Blue Knob State Park in Bedford County, where natural landscape vistas are a prime attraction.

Key Findings

Key findings from the Pennsylvania Energy Impacts Assessment include:

- Projections of between 750 and 2,900 new wind turbines developed on ridgetops and high plateaus by 2030, depending on the size of the Pennsylvania Alternative Energy Portfolio standard. There are currently an estimated 500 wind turbines built in the state.
- Wind turbine facilities are likely to be developed in half of the state's counties, especially along the Allegheny front in western Pennsylvania and on high Central Appalachian ridges in central and northeastern parts of the state;
- Nearly eighty percent of turbine locations are projected to be in forest areas, with forest clearing projected to range between 1,140 and 4,400 acres depending on the number of turbines developed. An additional range of 7,900 to 30,600 acres of forest interior habitat impacts are projected due to new edges created by turbine pads and roads;
- On a statewide basis, the projected forest clearing from turbine development is relatively minor, though some of the state's largest forest patches (>5,000 acres) could be fragmented into smaller patches by projected wind turbine development;
- Impacts on forest interior breeding bird habitats appear to be limited, largely because the overall footprint for the projected wind turbine facilities is small in comparison to the typical breeding range of these species in Pennsylvania. The study did not assess impacts to migratory pathways for birds or foraging bats.
- Relatively few watersheds ranked as "intact" by the Eastern Brook Trout Joint Venture are affected by projected wind turbine development. Several intact watersheds, however, could see several dozen wind turbines. In a number of cases, these small watersheds are projected to see significant Marcellus gas development as well. Given the cumulative impact of these activities, rigorously designed and monitored sediment control measures will be needed to protect sensitive brook trout populations.
- A relatively small handful of rare species occurrences tracked by the Pennsylvania Natural Heritage Program are found in areas with high probability for wind development. These species tend to be associated with rocky outcrops and barrens communities typically found on ridge tops, including the Allegheny wood rat, the eastern timber rattlesnake, and the northern long-eared Myotis bat.
- Wind development is not projected to occur on Pennsylvania's public lands. Existing and projected wind turbines, however, will be close to some of Pennsylvania's most heavily visited outdoor recreation areas where scenic natural vistas are a major attraction.

Additional Information

- American Wind Energy Association (2010). U.S. Wind Projects Database. http://www.awea.org/la_usprojects.cfm

- Black and Veatch (2010) Study for the Community Foundation for the Alleghenies: Assessment of a 15 Percent Pennsylvania Alternative Energy Portfolio Standard: http://www.cfalleghenies.org/pdf/aepss.pdf

- Federal Aviation Administration (FAA) permits for wind turbines: https://oeaaa.faa.gov/oeaaa/external/public/publicAction.jsp?action=showCaseDownloadForm

- Federal Aviation Administration (FAA), Obstruction Evaluation / Airport Airspace Analysis (OE/AAA): https://oeaaa.faa.gov/oeaaa/external/public/publicAction.jsp?action=showCaseDownloadForm

- Pennsylvania Wind Farms and Wildlife Collaborative: http://www.dcnr.state.pa.us/wind/index.aspx

- PA Game Commission (2007) Wind Energy Voluntary Cooperative Agreement and First Annual Report for the Wind Energy Voluntary Cooperative Agreement: http://www.portal.state.pa.us/portal/server.pt?open=514&objID=613068&mode=2

- Pennsylvania Department of Environmental Protection, Chapter 93 Water Quality Standards, Exceptional Value and High Quality Streams: data downloaded from Pennsylvania Spatial Data Access: (www.pasda.psu.edu)

- U.S. Department of Energy TrueWind 80 Meter Wind Resource Maps: http://www.windpoweringamerica.gov/wind_maps.asp

- U.S. Fish and Wildlife Service Wind Turbine Advisory Committee: http://www.fws.gov/habitatconservation/windpower/wind_turbine_advisory_committee.html

- U.S. Environmental Protection Agency summary of forest fragmentation effects: http://cfpub.epa.gov/eroe/index.cfm?fuseaction=detail.viewInd&lv=list.listByAlpha&r=219658&subtop=210

- Overview of forest fragmentation impacts on forest interior nesting species: http://www.state.nj.us/dep/fgw/neomigr.htm

- Overview of Pennsylvania High Quality and Exceptional Value Streams: http://www.dcnr.state.pa.us/wlhabitat/aquatic/streamdist.aspx

- Eastern Brook Trout Joint Venture intact brook trout watersheds: http://128.118.47.58/EBTJV/ebtjv2.html

- Overview of Carnegie Museum of Natural History, Powdermill Nature Reserve, and the Pennsylvania Game Commission's 2nd Pennsylvania Breeding Bird Atlas Project: http://www.carnegiemnh.org/powdermill/atlas/2pbba.html

- Pennsylvania Natural Heritage Program, including lists of globally rare and state endangered and imperiled species: http://www.naturalheritage.state.pa.us/

- U.S. Department of Agriculture, Natural Resources Conservation Service, National Agriculture Imagery Program: http://datagateway.nrcs.usda.gov/GDGOrder.aspx

January 11, 2012

Attn: dSGEIS Comments
New York State Department of Environmental Conservation
625 Broadway
Albany, NY 12233-6510

Dear Sir or Madam:

Enclosed please find the comments of Catskill Mountainkeeper, Delaware Riverkeeper Network, Earthjustice, the Natural Resources Defense Council and Riverkeeper on the Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program, Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Reservoirs, issued September 7, 2011, and draft regulations (Proposed Express Terms 6 NYCRR Parts 52, 190, 550-556, 560, 750.1, and 750.3), issued September 28, 2011.

Sincerely,

Wes Gillingham
Catskill Mountainkeeper

Maya van Rossum
the Delaware Riverkeeper, Delaware Riverkeeper Network

Deborah Goldberg
Earthjustice

Kate Sinding
Natural Resources Defense Council

Kate Hudson
Riverkeeper

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Memorandum

TO: Kate Sinding, Natural Resources Defense Council

FROM: Niek Veraart, Louis Berger Group

DATE: January 11, 2012

RE: Technical Comments Summary Report: Expert Team Review of the 2011 Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program and Proposed High-Volume Hydraulic Fracturing Regulations

1.0 Introduction

The Louis Berger Group, Inc. (LBG) is pleased to submit this comment report on the 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas and Solution Mining Regulatory Program and Proposed High Volume Hydraulic Fracturing (HVHF) Regulations to the Natural Resources Defense Council (NRDC) and its partner organizations, Earthjustice, Riverkeeper, Delaware Riverkeeper Network and Catskill Mountainkeeper. This comment report serves two primary purposes: 1) to provide general comments on the RDSGEIS and proposed regulations that are not limited to specific disciplines, and 2) to summarize the discipline-specific technical comments from NRDC's expert review team. The expert review team consisted of Harvey Consulting, LLC, Dr. Tom Myers, Dr. Glenn Miller, Dr. Ralph Seiler, Dr. Susan Christopherson, Meliora Design LLC, LBG, Kevin Heatley, Dr. Kim Knowlton, Dr. Gina Solomon, and Briana Mordick. The detailed technical comments from each author/organization are provided as attachments to this summary report and referenced as appropriate throughout.[1] Table 1 provides a complete list of technical comment attachments and summarizes the major topics areas addressed in each. Resumes for the members of the expert review team are provided in Attachment 12.

2.0 General Comments

2.1 RDSGEIS Fails to Address "Other Low-Permeability Shales"

The final scope and title of the RDSGEIS included other low-permeability shales, in addition to the Marcellus shale. The RDSGEIS makes it clear that development of other shales (including the Utica shale) is not only possible in the future, but is considered likely as evidenced by the inclusion of development of other shales in the Ecology & Environment. Inc. economic impact assessment.[2]

[1] All references cited and relied upon in the attached reports are hereby incorporated by reference into these comments. Hard and/or electronic copies of all references are available upon request.
[2] See the 11/23/2011 email from Steven Russo (NYSDEC) to Deborah Goldberg (Earthjustice) explaining the assumptions used in developing the scenarios for economic impact assessment include the development of "other shales."

Table 1
Technical Attachments to the Summary Comment Report

Attachment Number	Preparer	Topics Addressed
1	Harvey Consulting, LLC	Scope of SGEIS - Marcellus Shale Only Liquid Hydrocarbon Impacts Water Protection Threshold Well Casing Requirements Permanent Wellbore Plugging &Abandonment Requirements HVHF Design and Monitoring Hydraulic Fracture Treatment Additive Limitations Drilling Mud Composition and Disposal Reserve Pit Use and Drill Cutting Disposal HVHF Flowback Surface Impoundments at Drillsite HVHF Flowback Centralized Surface Impoundments Off-Drillsite Repeat HVHF Treatment Life Cycle Air Pollution Control and Monitoring Surface Setbacks from Sensitive Receptors Naturally Occurring Radioactive Materials Hydrogen Sulfide Chemical Tank, Waste Tank and Fuel Tank Containment Corrosion and Erosion Mitigation and Integrity Monitoring Programs Well Control and Emergency Response Capability Financial Assurance Amount Seismic Data Collection
2	Tom Myers, Ph. D.	Hydrogeology and Contaminant Transport Surface Water Hydrology Groundwater Quality Monitoring Setbacks from aquifers and public water supply wells Acid Rock Drainage
3	Glenn Miller, Ph.D.	Toxicology Hydraulic Fracturing Additives Naturally Occurring Radioactive Materials Contaminants in Flowback water and produced brines Wastewater Treatment issues
4	Ralph Seiler, Ph.D.	Radon in Marcellus Shale Natural Gas Naturally Occurring Radioactive Materials
5	Susan Christopherson, Ph.D.	Socioeconomic Impacts Pace and timing of natural gas development
6	Meliora Design, LLC	Water Quality Stormwater Erosion SPDES General Permit
7	The Louis Berger Group, Inc.	Noise and Vibration Visual impacts Land use Transportation Community character Cultural resources Aquatic Ecology
8[3]	Kevin Heatley, M.EPC LEED AP	Ecosystems and Wildlife
9	Kim Knowlton, DrPH	Climate Change and Public Health
10	Gina Solomon, M.D., M.P.H	Health Impact Assessment
11	Briana Mordick	Induced Seismicity

[3] Report prepared for and provided courtesy of the Delaware Riverkeeper Network.

The RDSGEIS adds some additional baseline geologic information on the Utica shale, but the environmental impacts specific to the Utica shale have not been addressed. For example, the Utica shale is almost twice as deep as the Marcellus shale, which means wells in the Utica shale will take longer to drill, would create more noise, would require more water, and would generate more waste and truck trips than wells in the Marcellus shale.

In addition to the incomplete study of deeper depth low permeability gas reservoirs, gas reservoirs at shallower depths than the Marcellus shale were not studied at all in the RDSGEIS. These shallower low-permeability shales pose development risks greater than those associated with the Marcellus shale because they are closer to protected water resources. Furthermore, the combined and/or concurrent exploitation of low-permeability shales at multiple depths may result in cumulative impacts not addressed in the RDSGEIS. The absence of the impact analyses of exploitation of shales at depths other than the Marcellus shale renders the RDSGEIS incomplete. NYSDEC should either evaluate additional information and analysis on the impacts of exploring and developing the Utica Shale and other unnamed low-permeability gas reservoirs, or acknowledge that there is insufficient information and analysis to study the impacts of this development. In the latter case, the RDSGEIS should conclude that its examination of impacts and mitigation measures is limited to the Marcellus Shale Gas Reservoir, and therefore any Utica Shale or other unnamed low-permeability gas reservoir development will warrant a site-specific supplemental environmental impact statement review or should be covered under another, future SGEIS process.

For additional detailed information supporting this comment, refer to Chapter 2 of the 2011 Harvey Consulting, LLC report (Attachment 1).

2.2 RDSGEIS and Regulations Fail to Protect the Environment from Non-HVHF Gas Development

While significant gaps remain as identified throughout these comments, the proposed regulatory framework for HVHF includes a number of improvements to NYSDEC's existing regulations to protect the environment from natural gas development. However, most of these improvements apply only to wells meeting the threshold to be classified as HVHF (defined as hydraulic fracturing using greater than 300,000 gallons of water).[4] NYSDEC is using a patchwork approach to regulating HVHF by adding new requirements on top of outdated requirements. A broader reform of the oil and gas development regulations is needed to address deficiencies in the existing regulations. This will ensure that best practice approaches are required for all natural gas wells in New York, including conventional wells and hydraulic fracturing using less than 300,000 gallons of water. Examples of reforms incorporated into the RDSGEIS and/or proposed regulations for HVHF that should apply to all wells include updated well casing requirements, emergency response plans and plans addressing the mitigation of noise, visual, transportation and ecological impacts.

2.3 RDSGEIS Fails to Address Indirect and Cumulative Impacts

The RDSGEIS fails to analyze important indirect and cumulative impacts as required by the State Environmental Quality Review Act (SEQRA). One of the most glaring examples of this is the

[4] The RDSGEIS arbitrarily increased the threshold for HVHF to 300,000 gal from 80,000 gal, as evaluated in the 1992 GEIS. There is no scientific justification given for the increase, and it effectively leaves all fracturing in the range 80,000-300,000 regulated by the existing rules without NYSDEC ever having conducted an environmental review showing that they are adequate for jobs that big.

RDSGEIS's failure to analyze the impacts of the pipelines and compressor stations that would be required to support the development of HVHF.

The RDSGEIS does not analyze any of the important impacts of pipelines and compressor stations (such as additional habitat fragmentation, noise and air pollutant emissions) based on flawed reasoning that such an analysis is not required because the pipelines would be reviewed under the Public Service Commission's Article VII process. The regulatory review process for pipelines is irrelevant—SEQRA requires state and local agencies to consider indirect "growth inducing" impacts. Pipelines and compressor stations are an indirect effect of the approval of HVHF. Without the approval of HVHF, there would be no reason to construct additional pipelines. Therefore, the pipelines/compressor stations and associated impacts cannot be separated from the environmental impact analysis of the HVHF regulatory program. The separate environmental review of the pipelines is, moreover, a form of segmentation, which is not permissible under SEQRA.[5] The additional natural gas pipelines and related infrastructure could also result in cumulative impacts when their impacts are combined with the impacts of HVHF that were analyzed in the RDSGEIS. The result of these deficiencies in the RDSGEIS is that the true impacts of the approval of HVHF have not been disclosed to the public and the requisite "hard look" under SEQRA has not been taken.

Similar to the treatment of pipeline infrastructure, the RDSGEIS also fails to analyze the cumulative impacts of numerous actions related to HVHF moving forward in New York, including the following:

- **Impacts from wastewater disposal and management**. The wastewater produced during the HVHF process is highly contaminated and could impact water resources if released into groundwater or surface water. While recognizing the problems with management of this water, the RDSGEIS fails to clearly state how this water will be either disposed in a manner that protects human health and the environment, or otherwise treated to remove the contaminants. While the RDSGEIS provides a range of alternatives, the RDSGEIS does not analyze the environmental or human health impacts associated with any of these disposal options. There are four possible treatment options for flowback and produced water discussed in the RDSGEIS: (1) reuse, (2) deep well injection, or (3) treatment in municipal or privately owned treatment facilities. None of these options is properly analyzed in the RDSGEIS, and the potential significant adverse impacts of each are therefore not disclosed nor possible mitigation identified. Further, effectively none of these options is likely to be accomplished in state, and the RDSGEIS implies that virtually all of the wastewater generated in New York will be managed out of state where regulations may be less stringent.

- **Impacts from Centralized Flowback Impoundments.** The RDSGEIS fails to analyze the impacts of centralized flowback impoundments based on statements from industry that they will not be "routinely" proposed. While site-specific SEQRA review would be required for any centralized flowback impoundment, NYSDEC should have addressed the potential for significant adverse cumulative impacts (particular air quality and water resources) arising from centralized flowback impoundments in combination with the other impacts of HVHF discussed in the RDSGEIS.

- **Impacts from seismic data collection.** Seismic data collection has the potential to create

[5] See 6 § NYCRR (617.2(ag)): "Segmentation means the division of the environmental review of an action such that various activities or stages are addressed under this Part as though they were independent, unrelated activities, needing individual determinations of significance."

habitat fragmentation through the clearing of long linear corridors, among other impacts. Seismic data collection is a reasonably foreseeable part of the development process and should have been considered as an aspect of the cumulative effects assessment in the RDSGEIS.

- **Impacts from liquid petroleum.** The development of the Marcellus shale has the potential to result in wells the encounter liquid hydrocarbons. If liquid hydrocarbons are found while drilling a shale gas well, additional wells and drill sites may be proposed to develop those oil resources. Liquid hydrocarbons found during natural gas exploration have the potential to contaminate the environment through spills and well blowouts. None of these impacts were considered in the RDSGEIS.

- **Impacts from land use change**. The RDSGEIS contains some information about potential economic benefits, but does not examine how increase population and employment would change land use. Changes in land use would result in greater demands on the transportation system as well as ecological impacts from new residential and commercial development (above and beyond the direct impacts of the well pad sites themselves).

Fundamentally, the RDSGEIS analyzes only certain elements of HVHF and fails to analyze all elements of the process, both individually and collectively.

2.4 Unenforceable Mitigation under the HVHF Regulatory Framework

As noted throughout the detailed technical review comments, the RDSGEIS includes numerous mitigation commitments that are not enforceable because they are not included in the proposed regulations or supplemental permit conditions.

To provide a consistent regulatory framework for industry and to protect the environment, mitigation measures that would be applied across all HVHF operations should be incorporated into the proposed regulations. Mitigation measures that are site-specific should be incorporated into the supplemental permit conditions. Mitigation measures that are suggested in the RDSGEIS itself that are unenforceable (i.e., not codified through regulatory or other mechanisms) should be acknowledged as such and reduced efficacy of mitigation due to the lack of enforcement should be analyzed and disclosed.

2.5 Setbacks

As a general matter, the setback requirements stipulated by proposed HVHF regulations are inadequate to protect public health and environmental quality. Table 2 provides a summary of the setbacks proposed in the RDSGEIS and/or regulations and the recommended revisions to the setbacks based on the expert reviews conducted for NRDC.

For example, the minimum setback according to the HVHF regulatory framework for a residence is 100-feet. This is inadequate considering the potential for blowouts to eject drilling mud, hydrocarbons, and/or formation water from a well onto adjacent waters and lands. Depending on reservoir pressure, blowout circumstances, and wind speed, these pollutants can be distributed hundreds to thousands of feet away from a well. Other risks to residences and schools within close proximity to HVHF operations include noise levels that damage hearing and, exposure to hazardous gases, chemicals, fuels, and explosive charges.

The potential radius of impact for explosions, fire, and other industrial hazards should be considered in the RDSGEIS and proposed HVHF regulations. For example, Fort Worth Texas uses the International Fire Code as the basis for its minimum 600’ setback from shale gas drilling operations. The figure below shows how the HVHF regulations setback distance requirements are significantly shorter and thus less protective than the requirements in other locations.

Comparison of NYS Setbacks from Homes and Public Buildings to Fort Worth, Texas Setbacks

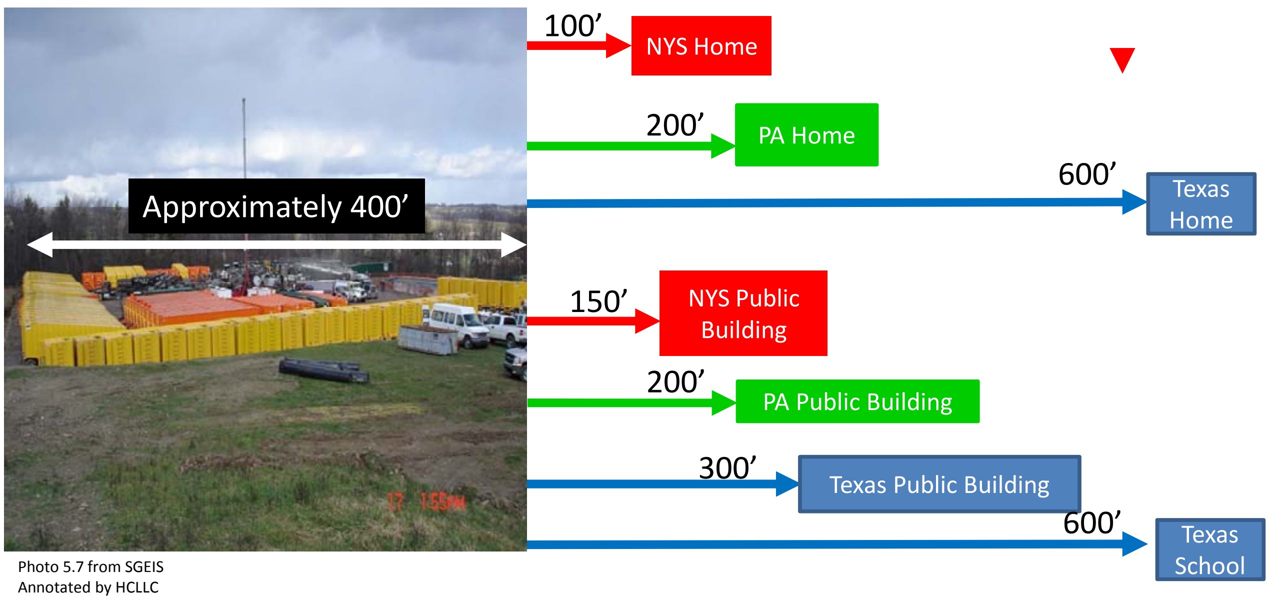

Photo 5.7 from SGEIS
Annotated by HCLLC
Distances shown by arrows drawn to scale

2.6 Insufficient Public Review of HVHF Permit Applications

The RDSGEIS fails to provide a clear and accessible process for public and local government access to site-specific HVHF activity information, while at the same time placing the burden on local government (and not the industry) to provide notice to NYSDEC that a HVHF activity may not be in compliance with local zoning or land use regulations (RDSGEIS pages 8-4 and 8-5). This essentially puts the regulatory burden on local government and at the same time fails to provide local government with access to the necessary information. The burden of demonstrating compliance with local government land use requirements should fall on the industry, not local government and the public. NYSDEC should require public notice of the availability of HVHF permit applications locally through publication of a notice in a newspaper of general circulation and statewide through a centralized website. Permit applicants should be required to provide copies of their application to the affected municipality. The public should have immediate online access to all supporting documentation submitted with each permit application and the public review timeframe should be no less than 30 days. The regulatory framework must incorporate a mechanism for public comments on permit applications to be considered by NYSDEC before the decision to grant or reject a permit application is made.

Table 2
Summary of Setback Recommendations

	Minimum Setback under Existing/Proposed HVHF Regulatory Framework	Recommended Minimum Setback	Rationale/Notes
Residences	100 feet 6 NYCRR § 553.2	1,320 feet	Protects from noise, explosions, fire, and other industrial hazards.
Public Buildings (including schools)	150 feet 6 NYCRR § 553.2		
Primary Aquifers	500 feet 6 NYCRR § 560.4	4,000 feet	The 500 feet setback for primary aquifers should be increased to 4,000 feet (the same setback distance adopted in the RDSGEIS for Filtration Avoidance Determination watersheds), unless a site specific analysis demonstrates there are no fractures connecting the bedrock with the aquifer and there are no obvious surface water pathways.
Principal Aquifers	500 feet in RDSGEIS (page 1-18) but not in the proposed regulations**	4,000 feet	The only difference between a primary and principal aquifer is the number of people potentially using the aquifer. Principal aquifers are thought to be productive enough to be an important source and contamination with fracking fluid or flowback could render them unusable without substantial remediation. Wells near principal aquifers should be subject to the same setback as well near a primary aquifer.
Public Water Supplies	2,000 feet (6 NYCRR § 560.4)	4,000 feet	The setback for public water supplies should be the same as for principal aquifers (4,000 feet) and the operator should identify the capture zone for flow to the well and identify the five year transport distance contour.
Private Drinking Water Wells	500 feet* (6 NYCRR § 560.4)	4,000 feet	Private and public wells should be protected to the same extent. NYSDEC should not allow the owner to waive the private well setback requirement because health and safety are at risk. More than just the “owner” may use the source, and the owner could sell to someone who does not understand the situation.
Stream, Storm Drain, Lake, or Pond	150 feet**	660 feet	The regulations currently contain conflicting and unclear requirements with respect to surface water resource setbacks. The regulations should be revised provide consistent setback requirements that are protective of water sources, including rivers, streams (perennial and intermittent), and lakes.
Filtration Avoidance Determination Watersheds	4,000 feet in RDSGEIS (page 7-56) but not in the proposed regulations	4,000 feet	Incorporate RDSGEIS setback commitment into regulations. In addition, the operator should be required to analyze the local geology to determine whether the groundwater divide would allow transport into the FAD watershed.
Floodplains	Wellpads prohibited in the 100-year floodplain (6 NYCRR § 560.4)	Wellpads prohibited in the 500-year floodplain	For wells that might operate for 30 years, there is a 26% chance of a 100-year flood occurring during the period the well would be operated. Wells should be prohibited within at least the 500 year return interval floodplain, because the damages from significant flooding could be very substantial.

*Setback can be waived by the landowner. The proposed regulations do not address setbacks for domestic use springs
** Setback could be waived based on site-specific analysis.

2.7 Impacts of Well Refracture Not Addressed

The assessments of environmental impacts in the RDSGEIS are all based on a single hydraulic fracturing treatment of each well. The RDSGEIS inappropriately relies on informal statements from industry that refracturing will be rare and does not quantify the number of HVHF treatments possible per well. The RDSGEIS under-predicts both the peak and cumulative impacts by not examining the reasonably foreseeable likelihood that Marcellus, Utica, and other low-permeability shale reservoirs will require more than one HVHF treatment, most likely two or three, over a several-decade long lifecycle. The RDSGEIS should quantify how many times a well may be fracture treated over its life, and provide a worst case scenario for water use and waste disposal requirements based on this scenario. Additionally, the RDSGEIS should examine the peak and cumulative impacts of multiple HVHF treatments over a well's life and propose mitigation to offset those reasonably foreseeable impacts. Refer to Chapter 16 of the Harvey Consulting, LLC report (Attachment 1) for more information supporting this comment.

3.0 Summary of Technical Comments

3.1 Liquid Petroleum Impacts

The RDSGEIS describes natural gas exploration and production, but does not address the potential for shale gas wells to also encounter liquid hydrocarbons. Natural gas exploration can identify oil and condensate development opportunities. If liquid hydrocarbons are found while drilling a shale gas well, additional wells and drill sites may be needed to develop those oil resources. Liquid hydrocarbons found during natural gas exploration have the potential to contaminate the environment through spills and well blowouts. The risk of oil spills during shale gas exploration has not been analyzed in the RDSGEIS. While blowouts are infrequent, they do occur, and are a reasonably foreseeable consequence of exploratory drilling operations. Blowouts can occur from gas and/or oil wells. They can last for days, weeks, or months until well control is achieved. On average, a blowout occurs in 7 out of every 1,000 onshore exploration wells. Two recent gas well blowouts occurred in Pennsylvania due to Marcellus Shale drilling.

The RDSGEIS should examine the potential for shale gas wells to also encounter liquid hydrocarbons. The RDSGEIS should also examine the incremental risks of oil well blowouts and oil spills, as well as the impacts from the additional wells and drill sites that may be required to develop oil resources identified by shale gas exploration and production activities.

The comments summarized in this section are covered in greater detail in Chapter 3 of the Harvey Consulting, LLC report (Attachment 1).

3.2 Well Casing Requirements

The comments summarized in this section are covered in greater detail in Chapters 5 through 8 of the Harvey Consulting, LLC report (Attachment 1).

3.2.1 Conductor Casing

Conductor casing is the first string of casing in a well and is installed to prevent the top of the well from caving in. The conductor casing requirements listed in the Proposed Supplementary Permit Conditions for HVHF and Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers should be codified in the proposed regulations and should apply to all natural gas wells drilled in NYS, not just HVHF wells. Additionally, NYSDEC should set a conductor casing depth criterion, requiring conductor casing be set to a sufficient depth to provide a solid structural anchorage. Regulations should specify that conductor casing design be based on site-specific engineering and geologic factors.

3.2.2 Surface Casing

Surface casing plays a very important role in protecting groundwater aquifers, providing the structure to support blowout prevention equipment, and providing a conduit for drilling fluids while drilling the next section of the well. Stray gas may impact groundwater and surface water from poor well construction practices. Properly constructed and operated gas wells are critical to mitigating stray gas and thereby protecting water supplies and public safety. If a well is not properly cased and cemented, natural gas in subsurface formations may migrate from the wellbore through bedrock and soil. Stray gas may adversely affect water supplies, accumulate in or adjacent to structures such as residences and water wells, and has the potential to cause a fire or explosion. Instances of improperly constructed wellbores leading to the contamination of drinking water with natural gas are well documented in Pennsylvania and other locations.

The RDSGEIS and proposed regulations include important improvements for surface casing that incorporate many of the comments provided by this working group in 2009. Notable improvements include requirements related to cement quality, casing quality, and installation techniques. Unfortunately, there are a number of inconsistencies between the permit conditions and the proposed regulations that create uncertainty about what will be required. The Harvey Consulting, LLC report provides recommendations for correcting these inconsistencies. Finally, there are a number of new surface casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. These requirements should be included in 6 NYCRR Part 554 (drilling practices for all oil and gas wells), and not just contained in 6 NYCRR Part 560 (drilling practices for HVHF wells).

3.2.3 Intermediate Casing

Intermediate casing provides a transition from the surface casing to the production casing. This casing may be required to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. The RDSGEIS and proposed regulations include important improvements for intermediate casing in comparison to the 2009 DSGEIS. Overall, NYSDEC's intermediate casing requirements for HVHF wells are robust. However, the remaining area for improvement in the proposed regulations is to establish intermediate casing and cementing standards for all wells that will not undergo HVHF treatment, but will require the installation of intermediate casing, on which the proposed regulations are silent. There are also a number of new intermediate casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. Those requirements should be included in 6 NYCRR Part 554 (drilling practices for all oil and gas wells), and not just covered in the new 6 NYCRR Part 560 (drilling practices for HVHF wells).

3.2.4 Production Casing

Production casing is the last string of casing set in the well. It is called "production casing" because it is set across the hydrocarbon-producing zone or, alternatively, it is set just above the hydrocarbon zone. Production casing is used to isolate hydrocarbon zones and to contain formation pressure. Production casing pipe and cement integrity is very important, because it is the piping/cement barrier that is exposed to fracture pressure, acid stimulation treatments, and other workover/stimulation methods used to increase hydrocarbon production.

The RDSGEIS and proposed regulations include substantial improvements for production casing. NYSDEC's proposed production casing requirements for HVHF wells are robust. The most notable improvement to the proposed regulations is that production casing must be set from the well surface through the production zone. This provides an additional protective layer of casing and cementing in the well during HVHF treatments. The RDSGEIS and proposed regulations require production casing to be fully cemented, if intermediate casing is not set. If intermediate casing is set, it requires production casing be tied into the intermediate casing. The proposed regulations also require the cement placement and bond be verified by well logging tools. These requirements are best practice. The Harvey Consulting, LLC report provides minor additional recommendations to improve consistency of the various requirements for production casing and highlights additional best practices that should be considered.

3.3 HVHF Design and Monitoring

Computer modeling is routinely used by industry to design hydraulic fracture treatments. During actual fracture stimulation treatments, data is collected to verify model accuracy, and the model is continually refined to improve its predictive capability. Data collected during drilling, well logging, coring, and other geophysical activities and HVHF implementation can be used to continuously improve the model quality and predictive capability. HVHF modeling is an important way of helping to ensure fracture treatments do not extend outside the target formation. Fracture treatments that propagate outside the shale zone (fracturing out-of-zone) reduce gas recovery and risk pollutant transport.

The RDSGEIS does not require well operators to develop or maintain a hydraulic fracture model. Instead, the RDSGEIS only requires the operator to abide by a 1000' vertical offset from protected aquifers and collect data during the HVHF job to evaluate whether the job was implemented as planned. Knowing whether a job was implemented as planned is only helpful if the initial design is protective of human health and environment. If the job is poorly planned, and is implemented as planned, that only proves that a poor job was actually implemented. Instead, NYSDEC needs to first verify that the operator has engineered a HVHF treatment that is protective of human health and the environment, and then, second, verify that the job was implemented to that protective standard. A rigorous engineering analysis is a critical design step. Proper design and monitoring of HVHF jobs is not only best practice from an environmental and human health perspective; it is also good business because it optimizes gas production and reduces hydraulic fracture treatment cost. Best practices for HVHF design and monitoring should be included as a mitigation measure, and codified in regulations as a minimum standard. These best practices include utilizing hydraulic fracture modeling prior to each fracture treatment to ensure that the fracture is contained in zone.

The comments summarized in this section are covered in greater detail in Chapter 10 of the Harvey Consulting, LLC report (Attachment 1).

3.4 Corrosion and Erosion Mitigation and Integrity Monitoring Programs

Downhole tubing and casing, surface pipelines, pressure vessels, and storage tanks used in gas exploration and production can be subject to internal and external corrosion. Corrosion can be caused by water, corrosive soils, oxygen, corrosive fluids used to treat wells, and the carbon dioxide

(CO_2) and hydrogen sulfide (H_2S) present in gas. High velocity gas contaminated with water and sediment can internally erode pipes, fittings, and valves. HVHF treatments, if improperly designed, can accelerate well corrosion. Additionally, acids used to stimulate well production and remove scale can be corrosive. The RDSGEIS includes a discussion on corrosion inhibitors used by industry in fracture treatments, but does not require them as best practice. Furthermore, the RDSGEIS does not require that facilities be designed to resist corrosion (e.g., material selection and coatings), nor does it require corrosion monitoring, or the repair and replacement of corroded equipment. Best corrosion and erosion mitigation practices and long-term well integrity monitoring should be evaluated and codified in regulations. Operators should be required to design equipment to prevent corrosion and erosion. Corrosion and erosion monitoring, repair, and replacement programs should be instituted.

The comments summarized in this section are covered in greater detail in Chapter 23 of the Harvey Consulting, LLC report (Attachment 1).

3.5 Well Control & Emergency Response Capability

Industrial fires, explosions, blowouts, and spills require specialized emergency response equipment, which may not be available at local fire and emergency services departments. For example, local fire and emergency services departments typically do not have well capping and control systems. The addition of an Emergency Response Plan (ERP) requirement to the RDSGEIS is a substantial improvement over the 2009 DSGEIS, which failed to address this issue. However, it is recommended that NYSDEC include a review, approval, and audit processes to ensure that quality ERPs are developed. Objectives of the ERP should include adequately trained and qualified personnel, and the availability of adequate equipment. If local emergency response resources are relied on in the ERP, operators should ensure they are trained, qualified, and equipped to respond to an industrial accident. Additionally, NYSDEC should have a program to audit ERPs via drills, exercises, equipment inspections, and personnel training audits.

The comments summarized in this section are covered in greater detail in Chapter 24 the Harvey Consulting, LLC report (Attachment 1).

3.6 Financial Assurance Amount

NYSDEC ignored comments submitted by this working group in 2009 requesting that the SGEIS examine financial assurance requirements to ensure there is funding available to properly plug and abandon wells; remove equipment and contamination; complete surface restoration; and provide adequate insurance to compensate nearby public for adverse impacts (e.g., well contamination). Although changes in financial assurance amounts would require legislative action, the analysis of this issue is necessary to fully disclose the potential adverse environmental impacts that would result in the absence of adequate financial assurances. Moreover, such an analysis would be an appropriate way of bringing this need for legislation to the attention of elected officials as appropriate mitigation for identified significant adverse impacts.

The importance of reevaluating financial assurance requirements is heightened when the inadequacy of the existing requirements is considered. For wells between 2,500' and 6,000' in depth, NYSDEC requires only $5,000 financial security per well, with the overall total per operator not to exceed $150,000. For wells drilled more than 6,000' deep, NYSDEC is proposing a regulatory revision that requires the operator to provide financial security in an amount based solely on the anticipated cost for plugging and abandoning the well (6 NYCRR § 551.6). These requirements are far less than those in other locations. Fort Worth, Texas requires an operator drilling 1-5 wells to provide a blanket bond or letter of credit of at least $150,000, with incremental increases of $50,000 for each additional well. Therefore, under Fort Worth, Texas requirements, an operator drilling 100 wells would be required to hold a bond of $4,900,000, as compared to $150,000 in NYS. In Ohio, an operator is required to obtain liability insurance coverage of at least $1,000,000 and up to $3,000,000 for wells in urban areas.

NYSDEC's financial assurance requirements should not narrowly focus on the costs of plugging and abandoning a well. Instead, NYSDEC's financial assurance requirements should include a combination of bonding and insurance that addresses the costs and risks of long-term monitoring; publicly incurred response and cleanup operations; site remediation and well abandonment; and adequate compensation to the public for adverse impacts (e.g., water well contamination). It is recommended that each operator provide a bond of at least $100,000 per well, with a cap of $5,000,000 for each operator. Additionally, NYSDEC should require Commercial General Liability Insurance, including Excess Insurance, Environmental Pollution Liability Coverage, and a Well Control Policy, of at least $5,000,000. If NYSDEC deviates from these financial assurance requirements, it should be justified with a rigorous economic assessment that is provided to the public for review and comment. Recommendations for financial assurance improvements for Marcellus Shale gas well drilling should be evaluated and included in the proposed regulations.

The comments summarized in this section are covered in greater detail in Chapter 25 of the Harvey Consulting, LLC report (Attachment 1).

3.7 Hydrogeology and Contaminant Transport

The RDSGEIS dismisses the potential for groundwater contamination due to HVHF on the basis of faulty science and unsupported assumptions.

1. The characterization of the hydraulic fracturing process and effects in the RDSGEIS is technically incorrect, leading to important impacts being overlooked.

2. The RDSGEIS assumes that the geologic layers above the Marcellus shale will stop contamination of aquifers without providing sufficient information on these layers, and ignoring the potential for existing faults and fractures to expedite contaminant transport. It also ignores studies which show that hydraulic fracturing has fractured formations as much as 1500 feet above the target shale, thereby providing pathways through the rock which the RDSGEIS relies on for stopping contaminant transport.

3. The RDSGEIS impact analyses are incomplete from a spatial perspective. The analyses focus on *local* impacts and fails to address the *regional* impacts of HVHF on the characteristics of the shale and the environmental implications of these changes. Such changes include increased shale permeability to water flow, which increases the risk of aquifer contamination over time.

4. The RDSGEIS analyses are incomplete from a temporal perspective. The analyses do not address the potential long-term aquifer contamination impacts by focusing on a time period of few days, assuming contamination has not occurred in other locations that lack the monitoring that would be necessary to detect contamination, and not considering evidence of the potential vertical movement of fracking fluid to near-surface aquifers as discovered under comparable conditions elsewhere.

Detailed technical supporting information for the deficiencies noted above is provided in the report prepared by Dr. Tom Myers (Attachment 2). The Myers report also provides a number of important recommendations for:

1. Improving and expanding the characterization of the hydraulic fracturing process and impacts in the RDSGEIS; and
2. Implementing measures as part of the review of specific well site proposals to avoid significant adverse aquifer contamination impacts.

The measures should include the following:

1. Mapping groundwater gradients above the Marcellus shale using existing data.
2. Requiring seismic surveys to locate faults prior to drilling.
3. Implementation of a long-term monitoring plan with wells established to monitor for long-term upward contaminant transport.

The groundwater monitoring at domestic wells proposed in the RDSGEIS is a scientifically improper method of monitoring the location of a contaminant plume because domestic wells are not designed for monitoring. Dedicated monitoring wells are necessary to prevent contamination of water wells by detecting contaminants before they reach the water wells.

3.8 Well Plugging and Abandonment

Wells that are not properly plugged can act as a preferential pathway for surface contaminants to impact groundwater resources. There are 2,114 wells that are at least 47 years old and some more than 87 years old that still have not been properly abandoned in NYS, and 2,026 wells where the age and condition is unknown (and must be assumed improperly abandoned). As a result, there is a risk that improperly planned HVHF wells or fractures could intersect abandoned wells and contaminate groundwater. Key recommendations from Chapter 9 of the Harvey Consulting, LLC report (Attachment 1) related to well plugging and abandonment (P&A) include the following:

- The SGEIS should examine: the number of improperly abandoned or orphaned wells in NYS requiring P&A in close proximity to drinking water sources or in close proximity to areas under consideration for HVHF treatments; whether a procedure needs to be put in place to examine the number, type, and condition of wells requiring P&A in close proximity to new shale gas development; and whether plugging improperly abandoned and orphaned wells should be required where such wells are in close proximity to new HVHF treatments.

- The SGEIS should include maps showing the location and depths of improperly abandoned, orphaned wells in NYS. These maps should correlate the locations and depths to potential foreseeable shale gas development and examine the need to properly P&A these wells before shale gas development occurs nearby. The SGEIS should assess the risk of a HVHF well intersecting a well that is not accurately documented in NYSDEC's Oil & Gas database and whether this poses and unmitigated significant impact to protected groundwater resources.

- The SGEIS requirements with respect to the plugging of improperly abandoned wells nearby proposed HVHF wells should be strengthened and incorporated in the proposed regulations.

3.9 Seismic Data Collection

Seismic surveys are used by industry to target hydrocarbon formations for exploration and appraisal drilling. Typically seismic surveys are conducted using vehicle-mounted vibrator plates that impact the ground or use explosive to create seismic waves which bounce off of subsurface rock strata and geologic formations. The reflected seismic waves are measured at various surface receivers. The rate that seismic energy is transmitted and received through the earth crust provides information on the subsurface geology, because seismic waves reflect at different speeds and intensity off various rock strata and geologic structures. Seismic operations are very labor intensive and require large amounts of equipment, personnel and support systems. Depending on the size of the area under study, and the type of equipment selected, seismic operations can require dozens to hundreds of personnel. In addition to seismic exploration equipment, there is a need for housing, catering, waste management systems, water supplies, medical facilities, equipment maintenance and repair shops, and other logistical support functions.

Significant surface impacts can be caused by extensive tree and vegetation removal to create straight “cutlines” to run seismic equipment (up to 20’-50’ wide). Lines need to be cut to run mechanical vibration equipment or set explosives to generate the seismic waves, and other seismic lines are cleared to set geophones to measure the seismic reflection.

The RDSGEIS does not include any analysis of the potential impacts or mitigation needed for two-dimensional (2D) or three-dimensional (3D) seismic surveys. If 2D or 3D seismic surveys are planned, or are possible in the future, the proposed HVHF regulations should codify a permitting process for these activities and institute mitigating measures in the RDSGEIS to minimize surface impacts and disruptions, and require rehabilitation of impacted areas. In addition, the increased industrial activity (e.g., economic impacts, noise, surface disturbance, wildlife impacts, etc.) associated with 2D and 3D seismic surveys should be examined in the RDSGEIS.

The comments summarized in this section are covered in greater detail in Chapter 26 of the Harvey Consulting, LLC report (Attachment 1).

3.10 Surface Water Hydrology

The RDSGEIS has addressed many of the deficiencies of the 2009 DSGEIS with respect to the treatment of hydrology issues. As discussed in the Myers report (Attachment 2), NYSDEC proposes to use the natural flow regime method (NFRM) for all regions by means of permit conditions. However, NYSDEC should verify the accuracy for the proposed methods for estimating passby flows at ungauged sites. Since NFRM is proposed to be applied everywhere (and not just in a specific case which would justify its use as a permit condition), it would be more appropriate for NYSDEC to include the use of the NFRM as a requirement in the regulations themselves. The following changes should be accounted for in the regulatory framework regarding the avoidance or reduction of potential impacts resulting from water withdrawal:

- NYSDEC should coordinate water withdrawals among operators so their withdrawals do not cumulatively cause flows to drop below the required passby flows at any point along the stream.
- The operator should establish a temporary flow/stage relationship with at least a staff gage that should be monitored.
- Passby flows should be maintained with consideration of the measurement error inherent in the technique. The operator should assume that the measurement method is overestimating

flow and therefore maintain a flow greater than the passby flow by as much as the error estimate.

3.11 Stormwater, Sedimentation and Erosion

All of the comments summarized in this section are covered in greater detail in the Meliora Design, LLC report (Attachment 6).

3.11.1 Cumulative Water Quality Impacts of Land Disturbance Are Not Addressed

The RDSGEIS provides only a very brief generic discussion of the potential land disturbance and associated stormwater and water quality impacts on surface waters from HVHF (and well drilling in general). The RDSGEIS makes no attempt to evaluate the cumulative impacts of HVHF activity on water resources, at either the small (headwater stream) scale, or the larger watershed scale. Even very general cumulative estimates of land disturbance, and its associated water quality impacts, are not provided. Since the original draft of the GEIS nearly twenty years ago, the use of improved geographic information system (GIS) software and modeling tools has expanded the ability of scientists, engineers, and regulators to quantify the scale and impact of proposed activities on water resources. Such analysis has become standard industry practice for watershed planning and the development of TMDL (Total Daily Maximum Load) studies to determine the level of pollutant load (and required pollutant load reduction) to meet water quality standards. The RDSGEIS fails to provide any such analysis, and instead only acknowledges stormwater impacts on water quality in the most general and generic manner, with little industry specific consideration, and no consideration of total or cumulative impacts. A more detailed and comprehensive evaluation of the amount of anticipated land disturbance and associated water quality impacts is essential to a full environmental impact analysis, and to any determinations by NYSDEC on the appropriate regulatory permitting requirements.

3.11.2 Stream Crossing Impacts Are Not Addressed

The RDSGEIS fails to consider the potential surface water impacts of stream crossing activity associated with HVHF well pads, most notably, stream crossings associated with gathering lines and access roads (to both well pads and compressor stations). Stream crossings and the associated water quality impacts are not fully addressed in the RDSGEIS, and are specifically not included in the Draft State Pollutant Discharge Elimination System (SPDES) General Permit. It is unclear how many stream crossings may be anticipated, and of these, how many will essentially be unregulated under current NYSDEC regulations. It is unclear what the anticipated environmental impacts of these stream crossings will be on water quality and aquatic systems. NYSDEC should provide some estimate of the extent of anticipated stream crossings, potential water quality impacts, and proposed requirements to regulate and mitigate these impacts.

3.11.3 Mitigation and SPDES General Permit Do Not Consider Existing Water Quality

With the exception of watersheds that have received Filtration Avoidance Determinations, the RDSGEIS (and associated Draft SPDES HVHF General Permit) do not provide any specific consideration of whether different performance requirements or standards are necessary to protect water quality for higher quality watersheds, impaired streams, or areas of denser well pad development on a watershed basis. There is no documentation to support the adequacy of the proposed setbacks to protect water quality in all situations (i.e., higher quality streams, percent of land disturbance within a watershed, site specific conditions such as steep slopes), and the setbacks discussed in the narrative of Chapter 7 are not clearly coordinated with EAF requirements in Appendices 4, 5, 6 and 10 and the Draft HVHF General Permit mapping and documentation requirements (and the Draft SPDES HVHF General Permit is presumably the regulatory mechanism for compliance). NYSDEC should provide some analysis or justification as to why a single set of performance requirements is applicable in all watersheds and all situations, regardless of stream designation or current levels of impairment or high quality.

3.11.4 SPDES General Permit Flawed

The Draft SPDES General Permit for HVHF is essentially a compilation of the NYSDEC's general permits for both construction activity and industrial activity. The general permit process is essentially "self-regulating," relying on the regulated industry to adhere to certain compliance requirements. It is not clear from the RDSGEIS's very limited discussion of land disturbance and surface water impacts that a general permit process is sufficient to protect water quality. It is also not clear that an industry that is not subject to local government review and approval, unlike virtually all other land disturbance activities addressed by general permits, can be adequately regulated through a general permit process. This is especially important for a heavy industrial activity that will be occurring in areas not zoned or accustomed to heavy industrial activity at the scale that will occur with HVHF. Finally, the general permit process does not provide a timeframe (or process) for public review, comment, and objection to any or all parts of proposed general permit coverage. Essentially, permit coverage is automatically granted to the industry by providing notice to the NYSDEC and meeting minimum performance requirements. The SPDES HVHF General permit should provide a process for public access to all information associated with HVHF land disturbance and water quality impacts, and that a process and timeline be developed to allow for public comment and appeal of general permit coverage for a specific site before general permit coverage is granted. The permit coverage timeline should be adjusted to provide for public comment and appeal.

3.12 Hazardous and Contaminated Materials Management

All of the comments summarized in this section are covered in greater detail in the Harvey Consulting, LLC report (Attachment 1) and the report of Dr. Glenn Miller (Attachment 3).

3.12.1 Disposal of Waste and Equipment Containing NORM

Naturally Occurring Radioactive Materials (NORM) can be brought to the surface in a number of ways during drilling, completion, and production operations:

- **Drilling**: Drill cuttings containing NORM are circulated to the surface.
- **Completion**: Wells stimulated using hydraulic fracture treatments inject water; a portion of that water flows back to the surface ("flowback") and can be contaminated by radioactive materials picked up during subsurface transport.
- **Production**: Subsurface water located in natural gas reservoirs, produced as a waste byproduct, may contain radioactive materials picked up by contact with gas or formations containing NORM (this water is called "produced water'). Equipment used in hydrocarbon production and processing can concentrate radioactive materials in the form of scale and sludge.

The RDSGEIS fails to establish clear cradle-to-grave collection, testing, transportation, treatment, and disposal requirements for all waste containing NORM. The RDSGEIS is improved relative to the 2009 DSGEIS in that it establishes radioactive limitations and testing in some cases, but testing is still not required in all cases (even when data uncertainty exists). Long-term treatment and disposal requirements are not robust for all waste types. Nor is there a process in place to provide the public with information on NORM handling over the project life. For example:

- Radioactivity treatment and disposal threshold levels are established (e.g., for produced water and equipment); however, it is unclear if there is sufficient treatment and disposal capacity in NYS to handle the volume and amount of radioactive waste that may be generated;
- NYSDEC assumes that some waste will not contain significant amounts of radioactivity; yet, this assumption is based on a very limited dataset;
- There is no testing requirement to verify NORM content in drill cuttings before they are sent directly to a landfill; and
- Road spreading of waste is not prohibited; it is deferred to a yet-to-be determined future process outside the SGEIS review.

Detailed collection, testing, transportation, treatment, and disposal methods for each type of drilling and production waste and equipment containing NORM should be included as a mitigation measure and codified in the NYCRR. Where data uncertainty exists, additional testing should be required. The radioactive content of waste should be verified to ensure appropriate transportation, treatment, and disposal methods are selected, and the testing results should be disclosed to the public.

3.12.2 Drilling Mud Composition and Disposal

Drilling muds may contain mercury, metals, Naturally Occurring Radioactive Materials (NORM), oils and other contaminates. The NYSDEC appropriately removed the statement that "*drilling muds are not considered to be polluting fluids"* from the proposed regulations in response to this working group's 2009 comments. This positive change is commendable, but there are two problems related to the regulation of drilling muds that remain:

- The RDSGEIS states that the vertical portion of wells would be "typically" drilled using compressed air or freshwater mud as the drilling fluid. There is no regulatory restriction on industry using toxic additives in drilling mud, with corresponding increases in the risks of water resources contamination during drilling, transport and disposal. NYSDEC should stipulate in the regulations the mandatory use of compressed air or freshwater mud and prohibit the use oil-based muds, synthetic-based muds and the use of toxic additives.
- The proposed regulations do not provide criteria for acceptable drilling mud disposal plans to ensure safe handling and disposal. The proposed regulations should require specific best practices for drilling mud handling and disposal.

3.12.3 Reserve Pit Use and Drill Cuttings Disposal

The RDSGEIS acknowledges the numerous environmental advantages of a closed loop tank system to manage drilling fluids and cuttings rather than reserve pits, but fails to require a closed loop tank system in all circumstances. The closed loop tank system is only required for wells without an acceptable acid rock drainage mitigation plan for onsite disposal and for cuttings that need to be disposed at a landfill because they contain toxic additives. The proposed regulations should prohibit reserve pits and require a closed loop tank system. Reserve pits should only be allowed where the applicant demonstrates that the closed loop tank system would be technically infeasible. The proposed regulations also should include testing of the shale to determine the extent of potentially acid generating material included in the cutting.

The RDSGEIS states that onsite disposal of water-based muds is permissible, despite the fact that these muds may contain mercury, metals and other contaminates. These contaminated muds would be put in direct contact with soils and groundwater, resulting in the potential for significant adverse environmental impacts not addressed in the RDSGEIS. Some portions of the RDSGEIS and proposed regulations vaguely reference a requirement for consultation with the NYSDEC Division of Materials Management prior to disposal of cuttings from water-based mud drilling, but this "consultation" improperly circumvents the proper public review that would be provided by reaching a decision on the disposal requirements for water-based mud and associated cuttings through the environmental review process.

3.12.4 Hydraulic Fracture Additive Limitations

The RDSGEIS and proposed regulations continue to rely solely on the drilling operators to (1) regulate themselves, and (2) select the lowest toxicity chemicals for use in fracture treatment additives.

The proposed regulations require documentation that the additives exhibit "reduced aquatic toxicity" and "lower risk to water resources" compared to alternate additives or documentation that alternatives are not equally effective or feasible. There are no specific criteria for determining what is an acceptable reduction in toxicity or an acceptable reduction in risk. Operators would still be allowed to use harmful chemicals merely by stating to NYSDEC that these are the only chemicals that would be "effective" or by showing that the chemicals they propose are slightly less toxic than the most toxic alternatives.

To address this problem, the RDSGEIS and proposed regulations should identify the type, volume and concentrations of fracture treatment additives that are protective of human health and the environment; include a list of prohibited additives; and require the use of non-toxic materials to the greatest extent possible.
NYSDEC should develop the list of prohibited fracture treatment additives based on the known list of chemicals currently used in hydraulic fracturing. The list of prohibited fracture treatment additives should apply to all hydraulic fracture treatments, not just HVHF treatments. NYSDEC should also develop a process to evaluate newly proposed hydraulic fracturing chemical additives to determine whether they should be added to the prohibited list. No chemical should be used until NYSDEC and/or the New York State Department of Health (NYSDOH) has assessed whether it is protective of human health and the environment, and has determined whether or not it warrants inclusion on the list of prohibited hydraulic fracturing chemical additives for NYS. The burden of proof should be on industry to demonstrate, via scientific and technical data and analysis, and risk assessment work, that the chemical is safe. Fracture treatment additive prohibitions should be included in the RDSGEIS as a mitigation measure and codified in the proposed regulations.

3.12.5 Centralized Surface Impoundments for HVHF Flowback Off-Drillsite

The 2009 DSGEIS disclosed significant adverse air quality impacts associated with centralized surface impoundments for HVHF flowback, which were found to emit over 32.5 tons of air toxics per year. However, this important impact information was removed from the RDSGEIS. Instead, NYSDEC improperly declined to analyze centralized surface impoundments based on statements by the industry that they would not "routinely propose" to use centralized flowback impoundments. The proposed regulations do not prohibit centralized surface impoundments, which would be appropriate mitigation for the significant adverse impact identified in the 2009 DSGEIS, and instead a separate site-specific SEQRA review would be required for them.

3.12.6 Chemical and Waste Tank Secondary Containment

NYSDEC appropriately codified a requirement for secondary containment for chemical and waste handling tanks in the proposed regulations. However, the proposed regulations do not specifically address secondary containment for chemical and waste transport, mixing and pumping equipment. The regulations should be revised to address secondary containment for transport, mixing and pumping equipment in order to minimize potential soil and water resource impacts from chemical spills. There are several other minor modifications to the proposed regulations for secondary containment detailed in Chapter 21 of the Harvey Consulting, LLC report (Attachment 1) to eliminate inconsistencies between various regulatory requirements.

3.12.7 Fuel Tank Containment

NYSDEC appropriately included a requirement for fuel tank secondary containment in the Proposed Supplementary Permit Conditions. However, this requirement is confused by inconsistent statements in the RDSGEIS that secondary containment is not required for *temporary* fuel tanks (page 7-34). In addition to correcting this inconsistency, the proposed regulatory framework for fuel tank containment should be substantively improved to be more protective of the environment through adoption of the following changes:

- Define clear criteria for adequate containment (e.g., using coated or lined materials that are chemically compatible with the environment and the substances to be contained; providing adequate freeboard; protecting containment from heavy vehicle or equipment traffic; and having a volume of at least 110 percent of the largest storage tank within the containment area).
- Include mandatory minimum setbacks from surface water features, homes and public buildings. The proposed regulations contain a setback for surface water resources, but only "to the extent practical."
- Explain how NYSDEC's requirements for fuel tank containment interface with federal requirements (40 CFR Part 112).
- Require tank inspections, spill prevention and spill alarm systems.
- Clarify whether vaulted, self-diking, and double-walled portable tanks will be allowed in cases where secondary containment is impractical, and codify the requirements for the use of those tanks, including inspections and spill prevention alarm systems.

3.13 Toxicology

This section addresses the toxicology-related issues associated with Naturally Occurring Radioactive Materials (NORM), hydraulic fracturing additives and waste disposal. For supporting technical information for these comments, refer to the technical reports of Dr. Glenn Miller (Attachment 3) and Dr. Ralph Seiler (Attachment 4).

3.13.1 Naturally Occurring Radioactive Materials

The Marcellus Shale is known to contain NORM concentrations at higher levels than surrounding rock formations. The primary environmental contamination risk associated with NORM is in production brines. Appendix 13 of the RDSGEIS presented some information on radioactivity characteristics of vertical wells in the Marcellus Shale in New York. However, the data in Appendix 13 identifies only 14-24% of the gross alpha radiation sources in the water samples. The sources of the other 75%+ of alpha radiation are not identified. The RDSGEIS explicitly acknowledges that the scientific understanding of NORM in production brine is incomplete.[6] NYSDEC should have obtained more information on the radiation sources in production brine as part of the SGEIS process because it is essential to NYSDEC's decision-making process and for NYSDEC to ensure that adequate regulations are in place before widespread HVHF occurs in New York. Even if the information could not have been reasonably obtained (which is not the case here), the proper approach for SEQRA compliance would have been to disclose the unavailable information in accordance with NYCRR §617.9 (b) (6)[7]:

One possible source of the unspecified alpha levels in production brines is polonium. Polonium-210 is 5,000 times more radioactive than radium and is highly toxic.[8] Polonium-210 is difficult and expensive to remove from drinking water and bioaccumulates in the environment. Before completing the SEQRA process, NYSDEC should determine if polonium is a significant component of alpha emission in formation waters and identify appropriate regulations that address polonium-contaminated wastewater to prevent water resource impacts. Specific technical recommendations regarding the analyses that should be conducted to determine the presence of polonium are provided in Attachment 4. Attachment 4 also addresses the potential for Polonium-210 exposure via build-up in natural gas delivery pipes.

3.13.2 Radon Exposure via Natural Gas Combustion

Radon is a cancer-causing, radioactive gas. Radon is known to be present in natural gas and will be delivered with the natural gas to consumers. The quantity of radon in natural gas is highly variable and has not been studied by NYSDEC in the Marcellus Shale. While normal natural gas use in properly ventilated burners are unlikely to contribute to radon concentrations in a closed space, poorly vented areas may well be a problem, and certain scenarios (e.g., high use of natural gas for industrial applications, restaurants that use gas burners) need to be subjected to risk assessment. At the very least, substantially more radon measurements need to be made. The risk is likely to be greatest in those areas that already have elevated radon in air, and that risk may be enhanced by the natural gas contribution. Any increase in radon exposure in the Southern Tier is of particular concern in terms of cumulative impacts given that the NYSDOH estimates the majority of homes in

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[6] 2011 RDSGEIS Page 5-142: "The data indicate the need to collect additional samples of production brine to assess the need for mitigation and to require appropriate handling and treatment options…."

[7] *In addition to the analysis of significant adverse impacts required in subparagraph 617.9(b) (5) (iii) of this section, if information about reasonably foreseeable catastrophic impacts to the environment is unavailable because the cost to obtain it is exorbitant, or the means to obtain it are unknown, or there is uncertainty about its validity, and such information is essential to an agency's SEQR findings, the EIS must:*

(i) identify the nature and relevance of unavailable or uncertain information;
(ii) provide a summary of existing credible scientific evidence, if available; and
(iii) assess the likelihood of occurrence, even if the probability of occurrence is low, and the consequences of the potential impact, using theoretical approaches or research methods generally accepted in the scientific community.

This analysis would likely occur in the review of such actions as an oil supertanker port, a liquid propane gas/liquid natural gas facility, or the siting of a hazardous waste treatment facility. It does not apply in the review of such actions as shopping malls, residential subdivisions or office facilities.

[8] http://www.who.int/ionizing_radiation/pub_meet/polonium210/en/index.html

the region have existing basement radon levels above the EPA "action level" of 4 pCi/L. Between 20 and 40 percent of homes in the several Marcellus Shale counties have long-term exposure to radon levels above the EPA limit in their living areas.[9] Before completing the SEQRA process, NYSDEC should analyze the cumulative health risk posed by additional radon exposure from Marcellus Shale natural gas combustion so that appropriate mitigation measures can be identified to address the issue.

3.13.3 Hydraulic Fracturing Additives

The RDSGEIS does not present sufficient information to analyze the toxicology risks posed by hydraulic fracturing additives. It does not address the toxicology risks generically or at the site level. The proposed regulations do not require permit applicants to provide sufficient information for the risks of these additives to be considered at the site level. The RDSGEIS provides a long list of potential additives (Tables 5.4 and 5.5), but does not analyze their potential environmental impacts. The list of additives is almost certainly incomplete, specific information on the chemicals is lacking, and the specific rate of usage is not offered. Thus, not knowing the composition of the specific additives nor the amounts in which they would be used during the HVHF process there is no basis for estimating the risk of these components with regard to their presence in the produced flowback or produced water.

The RDSGEIS misrepresents the presence of hydraulic fracturing additives in flowback. Table 6.1 of the RDSGEIS states that no non-naturally occurring additives were detected. However, most of these additives cannot be detected through standard methods. Table 6.1 should be revised to indicate which additives were actually capable of being detected by the analytical methods selected and the associated detection limits. This is a customary practice and standard. The proposed regulations should require testing of flowback water for acrylonitrile, a non-naturally occurring chemical that if detected provides a clear indication of off-site contamination by hydraulic fracturing.

3.13.4 Disposal of Contaminated Wastewater

The water that flows back immediately following hydraulic fracturing is heavily contaminated, primarily with the Marcellus formation contaminants, and represents the most problematic chemical contamination potential, due to the large volumes of contaminated water generated. The produced brines that are released during production generally have higher concentrations of naturally occurring contaminants than flowback waster (although lower volumes) and similarly represent a serious chemical contamination potential. Four problematic components of the flowback water and produced brines are present: the radioactive component (NORM); the inorganic salts, metals and metalloids; the organic substances (from the hydrocarbon formation) and the hydraulic fracturing additives. While recognizing the problems with management of this water, the RDSGEIS fails to clearly state how this water will be either disposed in a manner that protects human health and the environment, or otherwise treated to remove the contaminants. While the RDSGEIS provides a range of alternatives, the RDSGEIS does not analyze the environmental or human health impacts associated with any of these disposal options. Further, effectively none of these options is likely to be accomplished in state, and the RDSGEIS implies that virtually all of the wastewater generated in New York will be managed out of state where regulations may be less stringent.

There are four possible treatment options for flowback and produced water discussed in the RDSGEIS: (1) reuse, (2) deep well injection, or (3) treatment in municipal or privately owned treatment facilities. None of these options is properly analyzed in the RDSGEIS. Reuse is not a

[9] http://www.wadsworth.org/radon/

complete disposal option because residual salts and other contaminants must still be managed. Beyond reuse, the disposal options considered in the RDSGEIS only included injection wells, municipal sewage treatment facilities (of which there are currently none that are permitted to accept flowback and produced water) and private treatment plants (of which none currently exist in New York). The RDSGEIS did not consider whether there are other, less environmentally harmful, options that exist for flowback and produced water. More importantly, the RDSGEIS fails to evaluate the potentially significant adverse environmental impacts and human health risks associated with these disposal options.

3.14 Air Quality and Odors

For supporting technical information for the comments provided in this section, refer to Chapters 17 and 20 of the Harvey Consulting, LLC report (Attachment 1).

3.14.1 Air Quality Modeling Assumptions

The air quality analysis in the RDSGEIS contains some substantial improvements compared to the DSGEIS, but the assumptions used still warrant additional review and justification. For example, the RDSGEIS did not consider the reasonable worst case scenario air impacts resulting from simultaneous operations of spatially proximate well sites. In addition, the mobile source impact assessment under-predicts the number of miles that will be driven by heavy equipment to transport supplies to and haul wastes away from drillsites, especially wastewater that is hauled out of state to treatment and disposal facilities. Modeling for mobile source air impacts resulting from wastewater transport must be consistent with reasonable worst case scenario forecasts of wastewater volume (which impacts the number of truck trips needed per well site) as well as forecasted in and out of state disposal options (which impacts distance traveled per disposal). Limitations used in the modeling assumptions must all be translated into SGEIS mitigation measures and codified in the proposed regulations to ensure that the National Ambient Air Quality Standards will not be exceeded.

3.14.2 Air Quality Monitoring Program

The RDSGEIS includes a commitment to develop a regional air quality monitoring program to address the potential for significant adverse air quality impacts. However, more information is needed to understand the scope and duration of NYSDEC's proposed air monitoring program. A more rigorous monitoring program proposal is needed that identifies: the scope of the monitoring program; the location of the monitoring sites; the amount of equipment and personnel needed to run each site; the duration of monitoring proposed at each site; along with the cost. It is anticipated that a program used to assess both regional and local impacts will require long term monitoring stations placed in key locations, not just infrequent and unrepresentative sampling. The SGEIS should require the monitoring program to commence prior to Marcellus Shale gas development to verify background levels and continue until NYSDEC can scientifically justify that data collection is no longer warranted, in consultation with EPA. The obligation to fund the air monitoring program needs to be clearly tied to a permit condition requirement.

3.14.3 Greenhouse Gas Emissions Mitigation Plan

The RDSGEIS took a step in the right direction with the inclusion of a requirement for greenhouse gas emissions (GHG) impact mitigation plans. However, this requirement needs to be further defined. NYSDEC should require a GHG Mitigation Plan that provides for measureable emissions reductions and includes enforceable requirements. The GHG Impacts Mitigation Plan should list all Natural Gas STAR Program best management technologies and practices that have been determined by EPA to be technically and economically feasible, and operators should select and use the emission control(s) that will achieve the greatest emissions reductions. The GHG Impacts Mitigation Plan should be submitted and approved prior to drillsite construction, GHG controls should be installed at the time of well construction, and NYSDEC should conduct periodic reviews to ensure that GHG Impacts Mitigation Plans include state of the art emission control technologies. Further, the extent of compliance with adopted emission mitigation control plans should be documented throughout the well's potential to emit GHGs. The GHG Impacts Mitigation Plan requirement should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.4 Flare and Venting of Gas Emissions

Flares may be used during well drilling, completion, and testing to combust hydrocarbon gases that cannot be collected because gas processing and pipeline systems have not been installed. During production operations, high pressure gas buildup may require gas venting via a pressure release valve, or gas may need to be routed to a flare during an equipment malfunction. Reducing gas flaring and venting is widely considered best practice for reducing air quality impacts of natural gas development. The RDSGEIS air quality analyses of flaring assumed it would be limited to three days based on statements from industry, even though the actual duration should be longer. Planned flaring should be limited to no more than three days. In all other cases flaring should be limited to safety purposes only. If NYSDEC finds there is an operational necessity to flare an exploration well for more than a three-day period, the SGEIS impact analysis should evaluate the air pollutant impact, particularly the potential for relatively high short-term emission impacts, from longer flaring events, before approving such operations. The SGEIS should provide justification for allowing a maximum of 5 MMscf of vented gas and 120 MMscf of flared gas at a drillsite during any consecutive 12-month period. The RDSGEIS does not contain information to show that these limits are equivalent to the lowest levels of venting and flaring that can be achieved through used of best practices, and it is unclear if these rates were used in the modeling assessment. Flaring and venting restrictions should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.5 Reduced Emission Completions

Reduced Emission Completions (RECs, also known as "green completions") control methane and other GHG emissions following HVHF operations. RECs also reduce nitrogen oxide (NOx) pollution, which otherwise would be generated by flaring gas wells, and hazardous air pollutants (HAPs) and volatile organic compounds (VOCs) emissions, which otherwise would be released when gas is vented directly into the atmosphere. The RDSGEIS requires RECs where an existing gathering line is located near the well in question, which allows the gas to be collected and routed for sale. While the addition of this requirement represents a substantial improvement that protects air quality and increases the efficiency and productivity of wellsites, NYSDEC should consider expanding its REC requirements to more categories of wells—i.e., wells that are drilled prior to construction of gathering lines. Under the current proposal, a large number of wells could be exempt from the REC requirement, resulting in the flaring or venting of a significant amount of gas that could, instead, be captured for sale. Furthermore, NYSDEC proposes to postpone making a decision on the number of wells that can be drilled on a pad without the use of RECs until two years after the first HVHF permit is issued. NYSDEC should not defer the decision to implement RECs for two more years. The requirement to use RECs in all practicable situations should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.6 Gas Dehydrators

Dehydrator units remove water moisture from the gas stream. Dehydrator units typically use triethylene glycol (TEG) to remove the water; the TEG absorbs methane, VOCs, and HAPs. Gas dehydration units can emit significant amounts of HAPs and VOCs, and it is best practice to use control devices with gas dehydration units to mitigate HAP and VOC emissions. The 2011 RDSGEIS requires emissions modeling, using the EPA approved and industry standard model GRI-GlyCalc, and the installation of emission controls for dehydrator units emitting more than one ton per year of benzene. This is an important and substantial improvement. In addition to this requirement, natural gas operators should be required to evaluate the technical and economic feasibility of installing methane emission controls on gas dehydrators; installation should be mandatory unless an infeasibility determination is made. This requirement should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. This requirement should apply to all natural gas operations, not just HVHF operations.

3.14.7 Diesel Engine Emissions Control

NRDC's 2009 comments recommended limiting diesel engines to Tier 2 or higher. The RDSGEIS takes a step in the right direction by prohibiting "Tier 0" engines and requiring Tier 2 engines in most cases. To further strengthen air quality protection from diesel emissions SGEIS should examine whether it is possible to eliminate Tier 1 engine use altogether.

3.14.8 Leak Detection and Control

Unmitigated gas leaks pose a risk of fire and explosion, and contribute to GHG, VOC, and HAP emissions, that could otherwise be avoided by routine detection and repair programs. NYSDEC's proposed Leak Detection and Repair Program should be revised to require: a drillsite Leak Detection and Repair inspection at start-up; quarterly testing with an infrared camera with additional follow-up testing and repair if a leak is indicated; testing of all equipment located on the drillsite up to and including the gas meter outlet which is connected to the pipeline inlet. These requirements should be included in the SGEIS as mitigation measures and codified in the proposed regulations, and be required for all natural gas operations, not just HVHF operations.

3.14.9 Cleaner Power and Fuel Supply Options

The RDSGEIS did not examine cleaner power and fuel supply options as was requested in NRDC's 2009 comments. In suburban and urban areas of NYS, where a connection to the electric power grid is available, electric engines should be used in lieu of diesel wherever practicable, eliminating the local diesel exhaust from those engines. In rural areas, where highline power is not readily available, an operator should be required to evaluate whether there is a natural gas supply that could be used as fuel; if so, use of the natural gas supply should be mandatory to the extent practicable. Cleaner power and fuel selection requirements should be included in the SGEIS as a mitigation measure and codified in the proposed regulations. These requirements should apply to all natural gas operations, not just HVHF operations.

3.14.10 Hydrogen Sulfide (H_2S) ("Sour Gas") Emissions

In addition to air quality risks associated with emissions of criteria pollutants and air toxics resulting from natural gas development, additional air quality risks can occur as a result of the release of hydrogen sulfide (H_2S) or sour gas. H_2S gas produces a malodorous smell of rotten eggs at low concentrations, can cause very serious health symptoms, and can be deadly at the higher concentrations found in some oil and gas wells.

Therefore, proper handling of H_2S is important from both a quality-of-life and human-safety standpoint for workers and nearby public. The RDSGEIS does not analyze H_2S impacts based on the argument (supported by limited evidence) that to date H_2S has not been detected in high concentrations in HVHF operations in Pennsylvania. However, the early experience in Pennsylvania does not mean that there is no potential for H_2S issues to develop over time in New York.

A supplemental permit condition proposed in the RDSGEIS appropriately requires monitoring for H_2S during the drilling phase. However, a requirement should be added to the HVHF regulations to ensure that periodic monitoring occurs throughout production as gas fields age and sour. H_2S monitoring requirements should apply to all wells and therefore should be addressed through regulations, rather than through permit conditions that can be altered without public review. The regulations should stipulate that when monitoring detects H_2S, nearby neighbors, local authorities and public facilities should be notified of the risk of H_2S gas. They should be provided information on safety and control measures that the operator will be required to undertake to protect human health and safety. In cases where elevated H_2S levels are present, audible alarms should be installed to alert the public when immediate evacuation procedures are warranted.

3.15 Socioeconomics

This section addresses the socioeconomic impacts of HVHF. For supporting technical information for these comments, refer to the technical report from Dr. Susan Christopherson (Attachment 5).

3.15.1 NYSDEC's Socioeconomic Impact Analysis

Although NYSDEC has included more information on the social and economic impacts of gas development using HVHF in the RDSGEIS than it did in the 2009 draft, the RDSGEIS still does not effectively assess those impacts or provide appropriate mitigation strategies. There are a number of substantive concerns raised by the discussion of socioeconomic impacts presented in the RDSGEIS and by the Economic Assessment Report (EAR) prepared by NYSDEC's consultant, Environment and Ecology, on which that discussion is based.

1. The assessment of economic benefits (jobs and taxes) relies on questionable assumptions about the amount of gas extractable in the New York portion of the Marcellus Shale. The range of estimates for extractable gas appears to be skewed to the high end, leading to an overestimation of economic benefits.

2. The model used in the RDSGEIS to assess social and economic impacts presents natural gas development as a gradual, predictable process beginning with a "ramp-up" period and then proceeding through a regular pattern of well development over time. This model is misleading, and because many of the negative social and economic impacts of HVHF gas extraction (such as housing shortages followed by excess supply) are a consequence of unpredictable development, the model cannot appropriately assess those impacts.

3. The RDSGEIS does not assess public costs associated with natural gas development. A fiscal impact analysis of the base costs to the state and localities that will occur with any amount of HVHF gas development is required, along with an estimate of how costs will increase and accumulate as development expands.

4. The long-term economic consequences of HVHF gas development for the regions where production occurs are not addressed despite a widely recognized literature indicating that such regions have poor economic outcomes when resource extraction ends.

5. Mitigation of enumerated negative social and economic impacts of HVHF gas development is presumed to occur by means of phased development and regulation of the industry, but no evidence or information is provided to indicate whether, and if so how, that would occur.

3.15.2 Uncertainty and Volatility of Natural Gas Production and its Socioeconomic Impacts

The EAR's projections concerning population, jobs, housing, and revenue are predicated on the assumption of a regular, predictable roll-out of the exploratory, drilling, and production phases of the natural gas development process, rather than the irregular pattern typically associated with such development.

Natural gas drilling is a speculative venture and the commercially extractable gas from any particular well is uncertain. This central feature of natural gas development has critical implications for the economies of natural gas development regions. As production fluctuates, they may experience short- and medium-term volatility in population, jobs, revenues, and housing vacancies. The model used in the RDSGEIS to project socioeconomic impacts ignores those issues, however, and assumes instead that the HVHF natural gas development in New York will have a different pattern than that historically associated with such development. Rather than occurring in irregularly recurring waves (or "boom-bust cycles"), development in New York is assumed to be steady and predictable. Many of the economic benefits that the RDSGEIS and EAR associate with natural gas development are predicated on this unlikely gradual, regular development scenario, raising doubts about the projection of economic benefits based on that model.

The spatial distribution of impacts is also uneven. Some wells will have long production phases; others will have dramatic declines in productivity after a relatively short period. The uncertainties in the geographic extent of drilling and the potential for intensive development in "hot spots" have implications for social and economic impacts. If drilling is concentrated in particular locations rather than rolled out uniformly across sub-regions of the landscape (as was modeled in the RDSGEIS), wealth effects and tax revenues also will be concentrated in particular localities. The social and economic costs of spatially concentrated drilling, however, will be experienced across a much wider geographic area, because public services will be required in areas without HVHF development (and therefore not receiving tax revenues from drilling), but close enough to serve the transient population associated with the industry.

Contrary to the RDSGEIS' contention that the regularized development model "does not significantly affect the socioeconomic analysis," smoothing out the unpredictability and unevenness of development covers up many of the negative cumulative social and economic impacts that arise from the unpredictability of shale gas development. Finally, the RDSGEIS does not sufficiently model the resource depletion phase of the exploration, drilling, production, and resource depletion cycle and its implications for local and regional economies.

3.15.3 Economic Impact Study Fails to Address Costs

The 2011 RDSGEIS analyzes potential *economic benefits* of HVHF, but fails to provide the same level of analysis of the potential *costs* of HVHF. A central component of the EAR is use of a Regional Industrial Multiplier System (RIMS) model. This type of model is useful for comparing different types of investments and for examining inter-industry linkages, but it has a significant drawback as the central model for the RDSGEIS analysis of socioeconomic impacts because it can only project economic benefits. It cannot measure or assess the costs of proposed gas development using HVHF.

The RDSGEIS assumes, based on the RIMS model, that economic benefits from HVHF gas development, presumably including benefits to revenue, will be substantial, but there is no fiscal impact analysis or cost-benefit analysis to substantiate that assumption. A fiscal impact analysis is required, given that:

(1) Many purchases by drilling companies are tax exempt.

(2) Costs to the state that will reduce or offset tax revenues are not calculated.

(3) Substantial negative fiscal impacts are detailed in the EAR that are not quantified or fully acknowledged in the RDSGEIS, including public costs associated with the increased demand for community social services, police and fire departments, first responders, schools, etc., as well as costs associated with monitoring and inspection and infrastructure maintenance. Although experience in other shale gas plays demonstrates that these costs are likely, the RDSGEIS makes no attempt to calculate the costs and consider them in the context of a fiscal impact assessment.

(4) There is no analysis of the expected 2-3 year lag between immediate costs and anticipated revenues, during which communities will be faced with significant public service costs.

Given the inability of the EAR input-output model to address the costs of gas development and the significance of local and state costs to decisions about shale gas drilling in the state, revised EAR findings regarding costs must be prepared and an opportunity for public review and comment on the revised EAR afforded before the SGEIS is finalized.

3.15.4 Impacts on Other Industries

HVHF has the potential to have significant adverse effects on the viability of other industries in New York, particularly tourism and agriculture. In contrast with the pages of projected benefits from gas development, the RDSGEIS offers no detailed description and no quantitative analysis of the effects of HVHF development on existing industries and the associated impact on the state of New York's economy. This omission is particularly important for the counties defined in the EAR as "representative" because industries, including agriculture and tourism, are significant employers in those counties and are important to the overall economy of the State. There is no analysis of how the "crowding out" of existing industries may impact the regional or statewide economy or of the implications of the loss of industrial diversity to the long-term prospects for regional economic sustainability.

The inadequate assessment of the impacts on existing industries in the region that will be affected by HVHF gas development is problematic not only because the state does not have adequate information to assess costs and benefits of HVHF gas development, but also because negative impacts on industries such as tourism and agriculture, including dairies and wineries, will undermine state investments intended to support those industries. Given the importance of these industries in the state and regional economy, the evidence that they will be negatively affected by HVHF gas development should have been analyzed in detail and quantified when possible.

3.15.5 Housing and Property Value Impacts

The potential impacts of HVHF on the housing supply, housing costs, and housing financing are inadequately addressed in the EAR. In addition, the social and economic impacts of unpredictable shortfalls in housing followed by periods in which there is an excess supply are not addressed.

The report assumes that the current housing stock would be used to house any workers who move to the production region on a "permanent" (more than one year) basis. However, given the quality and age of the housing stock in the region, evidence from Pennsylvania indicates that it is likely that there will be a demand for new single-family housing. This new housing stock will create new and additional construction jobs, increasing population pressure, accelerating the "boomtown" phenomenon. This housing may also contribute to sprawl around urban population centers such as Binghamton. When drilling ceases, either or temporarily or permanently, the value of this new housing is likely to plummet. The social and economic impacts of unpredictable shortfalls in housing followed by periods in which there is an excess supply are not addressed. These impacts pose environmental justice concerns and require mitigation strategies.

With respect to impacts on property value, the EAR authors found that having a well on a property was associated with a 22% <u>reduction</u> in the value of the property; that having a well within 550 feet of a property increased its value; and that having a well located between 551 feet and 2,600 feet from a property had a negative impact on a property's value. Thus, "…residential properties located in close proximity to the new gas wells would likely see some downward pressure on price. This downward pressure would be particularly acute for residential properties that do not own the subsurface mineral rights." (EAR, 4-114). The EAR's assumption of recovering property values after the completion of HVHF gas development does not take into account the potential for re-fracturing of wells to increase their productivity or the effects of waves of development in which drilling moves in and out of an area. The prospect of industrial activity is what drives down investment in regions open to boom-bust development and also negatively impacts property values. A more definitive analysis of impacts of on property values, including mortgage availability, in regions affected by drilling is needed.

3.15.6 Effects on Employment

The oil and gas industry is not likely to be a major source of jobs in New York, because of the project-based nature of the drilling phase of natural gas production (rigs and crews move from one place to another and activities are carried out at each well) and because of its capital intensity (labor is a small portion of total production costs). The emerging information on actual employment created in Pennsylvania in conjunction with Marcellus drilling shows much smaller numbers than industry-sponsored input-output models projected.

Although the industry points to years of drilling experience in New York, the oil and gas industry employed only 362 people in New York State in 2009 (0.01% of the state's total employment). 43% of those workers (157) were employed in Region C, the region where vertical natural gas drilling is most significant in New York. Wages for these workers constituted 0.04% of the wages in the two-county region with almost 4,000 active gas wells.

In contrast, nearly 674,000 New York jobs were sustained by tourism activity last year, representing

7.9% of New York State employment, either directly or indirectly. New York State tourism generated a total income of $26.5 billion, and $6.5 billion in state and local taxes in 2010. In the Southern Tier alone, the tourism and travel sector accounted for 3,335 direct jobs and nearly $66 million in labor income in 2008. When indirect and induced employment is considered, the tourism sector was responsible for 4,691 jobs and $113.5 million in labor income. In addition, the travel and tourism sector generated nearly $16 million in state taxes and $15 million in local taxes, for a total of almost $31 million in tax revenue.

The RDSGEIS assumes that as the industry "matures" in the region, local residents will be trained and hired for drilling jobs. If, as has been the case with vertical drilling in New York State and in the Western US shale plays, development follows a more irregular pattern, then the higher paid technical jobs are less likely to evolve into stable local employment. In addition, the jobs in ancillary industries (retail and services) are likely to disappear and reappear as rigs leave and re-enter the region at unpredictable intervals.

In addition, many of the highest paid jobs associated with HVHF will not be filled locally. Occupational employment statistics geographical analysis of petroleum engineers, one of the most common occupations in the oil and gas industry, indicates that the states with the highest employment in this occupation are Texas, Oklahoma, and Louisiana. This data suggests that the rural areas of New York that are likely to experience the most intensive gas development will not see an increase in highly skilled and highly paid jobs in petroleum engineering.

The creation of high-paying jobs as a result of expenditures in industries outside the extraction industry is also likely to occur outside the production region. This is important because regions where natural resource extraction takes place (and especially rural regions with little economic diversity) have been found to end up with poorer economies at the end of the resource extraction process. Although the EAR asserts that as the natural gas industry grows, more of the suppliers would locate to the representative regions and less of the indirect and induced economic impacts would leave the regions, no evidence is presented to substantiate this assumption. The more likely outcome is indicated by a study of the impact of gas drilling on Western State economies, which found that natural gas drilling may have positive fiscal impacts at the state level, but negative fiscal impacts for the regions in which it occurs.

3.15.7 Regional Plan of Development Approach to Mitigating Socioeconomic Impacts

The mitigation chapter of the RDSGEIS implies that negative impacts will be mitigated through the permitting process and a secondary level of review triggered by the operator's identification of inconsistencies with comprehensive land use plans. The measures are only advisory. The RDSGEIS proposes no requirements to mitigate adverse socioeconomic impacts in this process.

Mitigation measures should be developed that would require operating companies to submit plans for exploration and development in a county or counties to county planning offices for review of cumulative impacts and mitigation (for example truck traffic routing), a model used in Western U.S. drilling regions. Because the RDSGEIS acknowledges that the pace and scale of development are difficult to ascertain until exploration and production begin to proceed, it is critical that a permit and regional Plan of Development (POD) review process be set up that alerts local officials to the need for long term planning for land use, schools, public safety and public health. The POD, outlining the pace, scale, and general location in which development will occur enables local government to anticipate and develop strategies to mitigate cumulative impacts. The near-term projections of development activity should include all secondary facilities (e.g., water extraction, waste disposal, pipeline construction) in the area to be affected. A POD would allow communities in that region to prepare for the disruption and negotiate the least disruptive and damaging development plan.

To further assist communities in planning for socioeconomic impacts, a series of reporting requirements should be incorporated into the RDSGEIS and regulations. As development activities begin and progress, the information provided in initial projections should be confirmed or revised on a semiannual basis. This information is critical to forecasting and meeting housing and service demands.

In addition, mitigation strategies need to be developed and described in the RDSGEIS that address long term costs to affected regions and the impacts of the resource depletion phase of the exploration, drilling, and development process, when population and jobs leave the region and tax revenues may be insufficient to pay for the capital investments made to serve the population influx during the drilling and production phases of development. Finally, mitigation strategies should include policies to prevent negative impacts on existing industries, including agriculture, tourism and manufacturing.

3.16 Traffic and Transportation

While the RDSGEIS improves upon the 2009 DSGEIS regarding estimates truck trip generation, the impact of HVHF on roadway congestion and safety has not been adequately addressed in the RDSGEIS.

The impacts of a typical multi-well development on congestion and safety should be analyzed in detail; such analysis should include a cumulative traffic effects analysis using a reasonable worst case development scenario. The reasonable worst case development scenario for regional traffic impacts should include indirect traffic generation associated with increased economic development and population growth attributable to natural gas extraction and related economic activity.

The LBG technical memo (Attachment 7) details the specific analyses that should be undertaken and describes how the transportation mitigation commitments described in the RDSGEIS should be incorporated into regulations or permit conditions to ensure they are enforceable. The transportation plan requirement in the RDSGEIS is a good first step, but additional detail is needed on the transportation plan including required contents, methodologies and impact criteria to make this mitigation measure meaningful.

3.17 Noise and Vibration

The construction and operation phase noise impact assessments presented in RDSGEIS are improved over the 2009 DSGEIS, but still contain important flaws that understate the impacts.

For example, the drilling and fracturing impact assessment presented is for one well, ignoring the cumulative impact of multiple wells being developed at the same time. Even using the analysis for a single well, the sound levels associated with the fracturing process are so extreme that hearing damage could result from exposure for 8-hours at a distance of 500 feet from the well pad.

Transportation-related noise impacts are not quantified in the RDSGEIS. Potential noise effects on wildlife are not evaluated, even though the noise of a single well and even more so the combination of noise of multiple wells could affect wildlife (especially sensitive bird species). The cumulative effects of noise on wildlife habitat and fragmentation effects of almost continual disturbance are not evaluated.

Vibration impacts and low-frequency noise impacts (which are associated with health impacts) are similarly not addressed in the RDSGEIS. The LBG technical memo details the specific analyses that should be undertaken and describes how the noise mitigation commitments described in the RDSGEIS should be incorporated into regulations or permit conditions to ensure they are enforceable.

Similar to the transportation plan requirement mentioned above, the noise mitigation plan requirement lacks specificity regarding the analyses required and the thresholds that trigger the need for mitigation. A best practice template for NYSDEC to consider adopting to specify the requirements for noise impact analysis and mitigation plans is the Alberta Energy Resources Conservation Board (ERCB) Noise Control Directive (#38).

3.18 Visual Resources

The RDSGEIS describes in very broad terms the potential direct and cumulative impacts of various phases of natural gas development on NYSDEC-designated visually sensitive resources. This assessment should incorporate best practices for analyzing visual impacts, such as identifying the relevant view groups, landscape zones and photo simulations of well development in various contexts.

The RDSGEIS mitigation section for visual resources suggests that mitigation measures would only be considered when designated significant visual resources (parks, historic resources, scenic rivers, etc.) are present *and* within the viewshed of proposed wells. This approach fails to consider visual impacts on nearby residences or tourists in areas where a significant visual resource is not present. In these situations, no mitigation would be required for individual wells to be consistent with the RDSGEIS. NYSDEC should make basic and low-cost mitigation measures mandatory for all well development sites (such as keeping lighting levels at the minimum level required and directing lights downward to minimize light pollution), regardless of whether or not state designated significant visual resources are present. For more information on the adequacy of the proposed mitigation measures and suggested changes, refer to the LBG technical memorandum (Attachment 7).

3.19 Land Use

The RDSGEIS fails to provide any analysis of the reasonably foreseeable cumulative land use impacts that would result if HVHF development goes forward in New York. This should be corrected by providing information on existing land use patterns and analyzing the impact of the level of development anticipated in the economic impact study on land use change. The RDSGEIS fails to provide any discussion of mitigation measures for land use impacts. Mitigation measures such as buffer distances for incompatible land uses should be described and incorporated into enforceable regulations or supplemental permit conditions, as appropriate. For more information on the adequacy of the proposed mitigation measures and suggested changes, refer to the LBG technical memorandum (Attachment 7).

3.20 Community Character

Community character is an amalgam of various elements that give communities their distinct "personality." These elements include a community's land use, architecture, visual resources, historic resources, socioeconomics, traffic, and noise.[10] The community character impact assessment portion of the RDSGEIS lists some of the community character impacts that could be expected (focused on demographic and economic impacts), but does not analyze the significance of these impacts or draw conclusions on how HVHF would affect community character in the short-term and long-term. The impact assessment does not mention the contribution of visual, land use or historic resource impacts to community character. The discussion of traffic and noise impacts is superficial (two sentences each). A complete community character impact assessment is needed (including regional cumulative impacts) to ensure appropriate mitigation measures are included in the HVHF regulatory framework.

3.21 Cultural Resources

In addition to the ecological effects of the massive ground disturbance and industrial development that will occur with HVHF in New York, the integrity of historic architectural resources, archaeological sites and culturally significant areas to Native Americans is also threatened. The RDSGEIS does not address comments provided by New York Archaeological Council during scoping in 2008 on cultural resource issues and does not adequately address this important resource topic. There is no section of the RDSGEIS specifically devoted to the direct, indirect and cumulative impacts of HVHF on cultural resource or any discussion of mitigation measures (except for impacts related to visual resources). The reliance on the 1992 GEIS for protection of cultural resources is not sufficient given the significantly different type and scale of impacts that could occur with HVHF and the length of time that passed since the 1992 GEIS was prepared. The role of the New York State Office of Parks, Recreation and Historic Preservation (OPRHP) in the review of individual permit applications is not clear in the RDSGEIS. In addition, the RDSGEIS does not explained how tribal consultation regarding impacts to cultural resources will be accomplished in a manner consistent with NYSDEC's own 2009 policy *Contact, Cooperation, and Consultation with Indian Nations*. Cultural resource impacts, mitigation measures and project-level review requirements must be addressed before HVHF is approved. Refer to the LBG technical memorandum for more information supporting these comments (Attachment 7).

3.22 Ecosystems and Wildlife

The ecological effects of HVHF and related infrastructure development include direct losses of habitat, fragmentation of existing habitats and indirect "edge effects" such as the spread of invasive species and noise disturbance of wildlife. The RDSGEIS qualitatively acknowledges these impacts and summarizes the findings of studies conducted in other locations, but does not provide build-out analyses that could quantify the range of cumulative habitat loss and fragmentation effects in New York. As evidenced by The Nature Conservancy's build-out analysis of Tioga County, such an analysis is readily achievable with existing GIS tools and datasets available to NYSDEC.[11] The RDSGEIS should include quantitative build-out analysis of habitat fragmentation and edge effects using estimates of development potential consistent with those developed for the RDSGEIS economic impact assessment and include the impacts from reasonably foreseeable infrastructure such as pipelines and compressor stations. Based on the results of the build-out analysis, NYSDEC should also analyze the potential diminution of critical ecosystem services associated with the disruption of forest cover and soils (carbon sequestration and storage, air filtration, watershed flow rates and volume, surface water quality and thermal condition).

[10] New York City Mayor's Office of Environmental Coordination. 2010. City Environmental Review Technical Manual.
[11] The Nature Conservancy. 2011 . "An Assessment of the Potential Impacts of High Volume Hydraulic Fracturing on Forest Resources."

The RDSGEIS characterizes the ecological impacts of HVHF as "unavoidable" and fails to consider alternative mitigation approaches that could lessen significant adverse environmental impacts. The site-specific ecological assessments and mitigation measures required by the RDSGEIS for well pads in grasslands greater than 30 acres and forest patches greater than 150 acres is a fragmented approach. It does not address the importance of landscape connectivity between habitat patches, which is essential to the movement and long-term viability of numerous species. A preferable methodology would be to set limits on deforestation, fragmentation and increases in impervious surface cover based upon ecological planning units such as the sub watershed. The SGEIS process should consider an alternative where rather than the current spacing unit requirements (which are intended to maximize production), land disturbance would be restricted region wide based on ecological carrying capacity. An ecologically oriented planning framework could significantly lessen the adverse impacts of HVHF development on terrestrial and aquatic systems.

In addition, consideration should be given to cumulative changes to land use within each watershed that could lead to detrimental changes in the affected stream to support critical species habitat. Limiting the percent increase in impervious area to less than five percent (inclusive of existing uses) in trout supporting watersheds, including upstream tributaries, would reduce the potential for adverse impacts to sensitive aquatic organisms and the loss of a waters best use designation.

The RDSGEIS fails to provide any meaningful guidance regarding the ultimate restoration of well pads, pipeline right-of-ways and access roads to full ecosystem functionality upon decommissioning. Effective restoration requires a comprehensive, site-level assessment of the existing plant community prior to disturbance and the use of local reference ecosystems as templates for restoration. Ecological restoration is based upon the concept of rebuilding degraded areas such that they are structurally and functionally similar to pre-disturbance conditions. Reclamation is not restoration. Grassy fields neither function in a biologically similar manner as a forest nor supply the ecosystem benefits of a forest system. The replacement of a decades-old, complex assemblage of woodland species with a simple mix of grasses is not "restoration". It may retard erosion but it does not replace the original functionality and structure of the displaced ecosystem.

For supporting technical information for these comments and additional comments on ecological impacts and mitigation measures, refer to the technical report from Kevin Heatley (Attachment 8) and LBG (Attachment 7).

3.23 Climate Change

The RDSGEIS ignores the real possibility that climate change impacts will undermine the safety of HVHF operations, frustrate mitigation efforts proposed by NYSDEC, and therefore exacerbate adverse impacts to the environment and human health resulting from HVHF operations. Increases in extreme weather events, such as floods, pose considerable obstacles to the safety of HVHF operations and infrastructure in and around low-lying coastal areas and floodplains. Precipitation changes coupled with enormous surface and groundwater withdrawals may result in modified groundwater flow patterns, which may cause unexpected groundwater contamination that jeopardizes drinking water supplies. Increased temperatures can volatilize dangerous chemical compounds at drill sites, exposing workers and nearby residents to airborne carcinogens at a rate greater than would be expected by modeling baseline temperatures without climate change. Remarkably, the effect of climate change on the availability of water resources is ignored in the section on the cumulative impact of water withdrawals, and no provision is made for situations where HVHF operations and public needs may conflict over water usage. Underscoring these concerns is the notable failure of NYSDEC to conduct a comprehensive Health Impact Assessment, despite the real possibility that climate change impacts confluent with HVHF operations can pose serious human health problems. Reliable reports on the effect of climate change on New York abound, including some produced within the last year by New York governmental bodies. The RDSGEIS fails to include current information relevant to climate change's potential effects on New York State, which may pose potentially significant adverse environmental and public health threats in conjunction with HVHF operations that should be identified and mitigated to the maximum extent possible.

For supporting technical information regarding these comments, refer to the technical report from Dr. Kim Knowlton (Attachment 9).

3.24 Health Impact Assessment

Numerous health concerns have been associated with natural gas development using hydraulic fracturing, and while the RDSGEIS addresses some aspects of a subset of these health issues, it fails to address other important health risks. The RDSGEIS not only omits several issues, but also it only addresses only some aspects of other issues such as air, water quality, and heightened traffic without fully considering health impacts in those areas. Lastly, it doesn't consider health issues as a group in a formal Health Impact Assessment (HIA), including interactive effects on the health of local residents and communities. A full HIA as part of the RDSGEIS is a necessary component, as there are already numerous reports of health complaints including dizziness, sinus disorders, depression, anxiety, difficulty concentrating, and many others, among people who live near natural gas drilling and fracturing operations in other states. Without a full assessment and mitigation of the impacts of the risks, the health of New York State residents and communities is likely to suffer.

For supporting technical information regarding these comments, refer to the technical report from Dr. Gina Solomon (Attachment 10).

3.25 Induced Seismicity

The RDSGEIS fails to require operators of HVHF wells to consider the risk of induced seismicity when siting wells and designing hydraulic fracture treatments. The justification provided is that high volume hydraulic fracturing is not expected to cause induced seismicity that will result in adverse impacts. Since the RDSGEIS was written, hydraulic fracturing has been confirmed to have caused induced seismicity strong enough to be felt at the surface. The RSDGEIS assumes that operators will manage seismic risks voluntarily and makes statements regarding the frequency of use of seismic monitoring techniques that are internally contradictory. It also fails to recognize the potential significance of unmapped faults and relies too heavily on the occurrence of natural seismicity as a future predictor of the potential for induced seismicity. Finally, it underestimates the potential adverse consequences of induced seismicity, which include risks to drinking water, well integrity, private and public property, and New York City drinking water supply infrastructure. The RSDGEIS provides insufficient analysis and scientific evidence to support its conclusion that regulations to reduce the risk of induced seismicity from hydraulic fracturing are not necessary. The RSDGEIS must require operators to evaluate and manage the risk of induced seismicity from hydraulic fracturing through proper site characterization and hydraulic fracture treatment design.

For supporting technical information regarding these comments, refer to the technical report from Briana Mordick (Attachment 11).

Attachment 1

Harvey Consulting, LLC.

2011 NYS RDSGEIS

Revised Draft Supplemental Generic Environmental Impact Statement On the Oil, Gas & Solution Mining Regulatory Program

Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs and

Proposed Revisions to the New York Code of Rules and Regulations

Best Technology and Practice Recommendations

Report to:

Natural Resources Defense Council (NRDC)

Prepared by:

HARVEY CONSULTING, LLC.

Oil & Gas, Environmental, Regulatory Compliance, and Training

January 9, 2011

Contents

1. Introduction

This report responds to the Natural Resources Defense Council's (NRDC), and its partner organizations Earthjustice, Inc., Riverkeeper, Inc., Catksill Mountainkeeper and Delaware Riverkeeper Network, request for a review of the New York State (NYS) 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas & Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs and proposed revisions to the New York Code of Rules and Regulations (NYCRR).

NRDC, and its partners, requested a technical review of the RDSGEIS and the proposed revisions to the NYCRR to determine if best technology and practices were included. NRDC has also commissioned additional experts; therefore, this list of recommendations is not exhaustive and is complementary to the work assigned to other experts. A complete list of expert recommendations can be found in the summary cover letter submitted by The Louis Berger Group, Inc., on behalf of NRDC, to the New York State Department of Environmental Conservation (NYSDEC) during the RDSGEIS public comment period.

This report makes recommendations for improving the SGEIS and the proposed revisions to the NYCRR. Overall, HCLLC found that NYSDEC made a number of significant improvements in both the RDSGEIS and the proposed revisions to the NYCRR. HCLLC commends NYSDEC for integrating a number of new best practices and technology alternatives into its 2011 RDSGEIS and proposed regulations.

This report highlights the RDSGEIS areas of improvement and reinforces the importance of retaining those improvements in the final SGEIS and the proposed NYCRR revisions. However, there remain significant areas for improvement. This report provides additional technical justification and scientific support for best practices and technology that warrant further NYSDEC consideration. It also recommends area of further study. Recommendations are highlighted in blue text boxes throughout the document.

A systemic problem persists in the 2011 RDSGEIS, where NYSDEC proposes to build on the existing 1992 Generic Environmental Impact Statement (GEIS) for oil and gas drilling in NYS by providing additional information on the Marcellus Shale reservoir and high-volume hydraulic fracturing without addressing the fact that the technology and practices required by the 1992 GEIS are over two decades old.

Since 1992, numerous best technology and best management practice improvements have been made in the oil and gas industry. By relying on 1992-vintage decisions and technology as the foundation for Marcellus Shale development, NYS' RDSGEIS starts with an unstable foundation. This problem is magnified in the proposed revisions to the NYCRR where NYSDEC proposes to retain, with little revision, antiquated technology and practices for all oil and gas development in NYS, while proposing that new technology and practices only apply to HVHF operations. This creates a technically and scientifically unsupported two-tiered system for oil and gas regulation in NYS.

Accordingly, the first and most logical step in the State Environmental Quality Review Act (SEQRA) analysis is to examine the 1992 GEIS foundation and identify new best technology and best practice improvements have been made since 1992 that warrant adoption. Then, and only then, can NYS build a well-supported incremental analysis that examines the impact of new techniques such as horizontal drilling and high-volume fracture treatments.

2. Scope of SGEIS – Marcellus Only

Background: In 2009, NYSDEC proposed that the SGEIS cover all horizontal drilling and HVHF in low-permeability gas reservoirs, at all depths. However, only the Marcellus Shale Gas Reservoir was studied in any detail. The DSGEIS was incomplete for all other low-permeability gas reservoirs.

In 2009, HCLLC recommended that NYSDEC either include additional information and analysis on the impacts of exploring and developing other low-permeability gas reservoirs or limit the scope of the SGEIS to the Marcellus Shale Gas Reservoir.

NYSDEC's consultant, Alpha Geoscience, disagreed with HCLLC's recommendation to limit the SGEIS scope to the Marcellus Shale, stating that the time to modify the scope had lapsed.[1] Alpha Geoscience concluded that it would be best for NYSDEC to determine at a future date, once a specific application was before them, whether the SGEIS covered High-Volume Hydraulic Fracturing (HVHF) operations in other low-permeability reservoirs.

HCLLC disagrees with Alpha Geoscience's recommendation, because it lacks technical and scientific basis and misconstrues HCLLC's recommendation. HCLLC did not recommend that other low-permeability gas reservoirs be excluded from the analysis because they should not be studied at all. On the contrary, HCCLC recommended that if low-permeability gas reservoirs were included in the SGEIS, they should be thoroughly studied. The 2009 DSGEIS should have included a complete assessment of the Marcellus **and** all other low-permeability gas reservoirs in NYS; however, it did not. Unfortunately, the 2011 RDSGEIS suffers from the same lack of data on other low-permeability gas reservoirs.

Consequently, there is a technical and scientific choice that needs to be made in declaring whether the SGEIS content satisfies its title. Either the SGEIS had to be revised to cover all low-permeability gas formations in NYS, or the SGEIS had to conclude that NYSDEC has insufficient data and/or resources to examine anything more than the Marcellus Shale at this time, and limit the scope of the SGEIS.

HCLLC's 2009 recommendation was made to ensure the SGEIS document title matches its content. The title of the SGEIS purports to provide an environmental impact analysis on all low-permeability gas reservoirs, yet, as explained in HCLLC's 2009 comments, the SGEIS did not provide sufficient analysis of the Utica Shale, and provided no analysis of the other Lower Paleozoic, Devonian (other than Marcellus), and Middle to Upper Paleozoic low-permeability gas reservoirs.[2,3] If NYSDEC has additional information to support a complete SGEIS for the Marcellus **and** all other low-permeability gas reservoirs, it should certainly include that complete assessment.

Unfortunately, the 2011 RDSGEIS suffers from the same narrow focus on the Marcellus shale. There was little additional work completed to advance NYSDEC's understanding of exploration and development impacts from the Utica Shale and other low-permeability gas reservoirs.

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[1] Alpha Geoscience, Review of the DSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA on January 20, 2011, Page 3.

[2] Ryder, R.T., 2008, Assessment of Appalachian Basin Oil and Gas Resources: Utica-Lower Paleozoic Total Petroleum System: U.S. Geological Survey Open-File Report 2008–1287.

[3] Milici, R.C., and Swezey, C.S., 2006, Assessment of Appalachian Basin Oil and Gas Resources: Devonian Shale-Middle and Upper Paleozoic Total Petroleum System: U.S. Geological Survey Open-File Report 2006-1237.

2011 RDSGEIS: The 2011 RDSGEIS provides some additional information on the Utica Shale Gas Reservoir, mostly in the form of geologic assessment. However, the RDSGEIS does not examine the peak or cumulative impacts of Utica Shale development.

No additional information is provided in the 2011 RDSGEIS on other low-permeability gas reservoirs in the region. The 2011 RDSGEIS states that industry's main focus in the near term is the Marcellus and Utica Shales; however, NYSDEC wants to cover all other low-permeability formations in the SGEIS because it may receive applications in the future for those formations:

> *The Department of Environmental Conservation (Department) has received applications for permits to drill horizontal wells to evaluate and develop the Marcellus and Utica Shales for natural gas production…**Other shale and low-permeability formations in New York may also be targeted for future application of horizontal drilling and high-volume hydraulic fracturing** [emphasis added].* [4]

Chapter 4 provides a geologic description of the Marcellus and Utica shale gas reservoirs; however, no other low-permeability gas reservoirs are studied. Yet, it is well known that most unconventional reservoirs vary in mineralogy, permeability, rock mechanics, and natural fracture parameters (length, orthogonal spacing, connectivity, anisotropy) and that there will be differences between formations that could lead to different drilling, stimulation, and development techniques.

Chapters 5 and 6 provide an analysis of drilling, fracturing, and development approaches in the Marcellus Shale Gas Reservoir. Chapters 5 and 6 are essentially silent on how the Utica Shale Gas Reservoir would be developed. No other low-permeability gas reservoirs are examined.

A search of the 1537 page electronic version of the RDSGEIS for the term "low-permeability gas reservoirs" shows that the term is only used a few times in the entire document. This term is used twice in the Executive Summary, where NYSDEC concludes that it has effectively studied "low-permeability gas reservoir" air quality impacts; yet, as further explained in Chapter 17 of this report there is insufficient information in the RDSGEIS to support that conclusion. The next occurrence of the term "low-permeability gas reservoirs" is not found until page 618 in the Air Quality Section, where again, NYSDEC states that it has included the impacts of "low-permeability gas reservoirs" in the air quality analysis; yet, there is insufficient information in the RDSGEIS to support that conclusion. The next occurrence, after the Air Quality Section, is found at page 1008, where NYSDEC defends exclusion of pipeline and compressor stations. A few minor references to this term are found at page 1071 in Chapter 9 (Alternative Actions). More simply put, the RDSGEIS contents do not match the title, and that there is insufficient information contained in the RDGSEIS to support development of all unnamed, unanalyzed low-permeability gas reservoirs in NYS. NYS has not developed a technical or scientific case to justify that the impacts described for the Marcellus Shale are representative of the peak or cumulative impact that would result from development of all unnamed, unanalyzed low-permeability gas reservoirs in NYS.

The 2011 RDSGEIS does not include a complete list of the formation names that it considers fit under the umbrella term of "low-permeability" formations. The only place that the term "low-permeability" formation is defined is in the Glossary at the end of the document:

> *Gas bearing rocks (which may or may not contain natural fractures) which exhibit in-situ gas permeability of less than 0.10 milidarcies.* [5]

[4] 2011 NYSDEC, RDSGEIS, Page 1-1.

[5] 2011 NYSDEC, RDSGEIS, Glossary.

Using this definition, a low-permeability formation could include a shale, sandstone, limestone or other formation that is gas bearing with a permeability of less than 0.10 milidarcies. The RDSGEIS does not address the scope of the formations that could be encompassed by this definition.

Figure 4.2 of the RDSGEIS[6] includes a stratigraphic section showing existing known oil and gas intervals above the Marcellus and Utica Shales, including numerous shale and other low-permeability formations that are known to exist, that were not examined in the SGEIS.

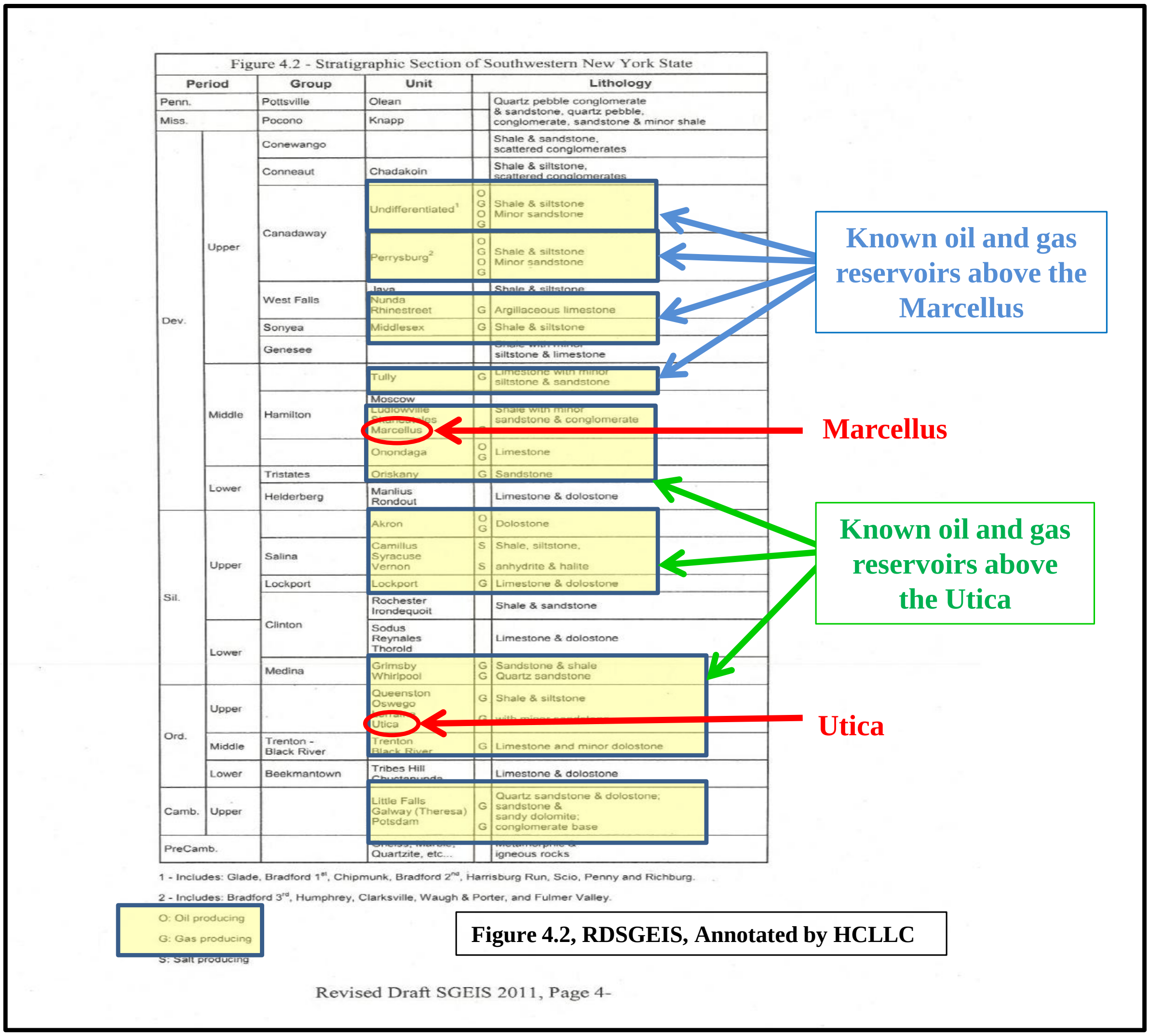

Figure 4.2, RDSGEIS, Annotated by HCLLC

On the next page is a table summarizing historical oil and gas production data from 1967 to 2010 in NYS.[7] This table shows that there is numerous gas zones present both above and below the Marcellus Shale that have been producing gas. Some of these reservoirs are low-permeability reservoirs that may be further developed using horizontal drilling and hydraulic fracturing techniques. Additionally, this table shows that there has been no Utica Shale production in NYS from 1967 to 2010; therefore, little is known about its productivity or how it may be developed.

[6] 2011 NYSDEC, RDSGEIS, Page 4-7.

[7] NYS Oil & Gas Data Summary 1967-2010, compiled by Briana Mordick, NRDC, December 2011, using NYS data found at http://www.dec.ny.gov/energy/1601.html. 1967-1999 data came from summary production history files. 2000-2010 data came from oil and gas production files.

NYS Oil & Gas Data Summary 1967-2010							
		Formation	Oil (bbl)	Gas (mcf)		Oil (bbl)	Gas (mcf)
		DEVONIAN SHALE	12,274	323,975			
		UPPER DEVONIAN	364,054	881,848	DEVONIAN SHALE	376,328	1,208,697
		UPPER DEVONIAN SHALE	-	2,874			
		Canadaway Undifferentiated					
		GLADE	1,392,255	449,124			
		BRADFORD	7,665,427	1,639,511			
		BRADFORD 1ST & 2ND	21	-			
		BRADFORD & CHIPMUNK	416,357	676,506			
		Bradford 1st & Chipmunk	6,609	2,497			
		CHIPMUNK, BRADFORD 1ST & 2ND	44,943	10,217			
		CHIPMUNK	7,369,293	1,012,975			
		CHIPMUNK & BRADFORD 2ND	2,454,948	16,415			
		BRADFORD SECOND	21,724	2,520			
		CHIPMUNK, BRADFORD 2ND & 3RD	237,195	162,809	CANADAWAY UNDIFFERENTIATED	23,945,472	7,271,139
	Upper	Chipmunk, Bradford 1st,2nd,3rd	9,719	8,321			
		BRADFORD 2ND & 3RD	37,780	9,353			
		CHIPMUNK & BRADFORD 3RD	33,186	34,858			
		Chipmunk & Harrisburg	2,442	1,026			
Devonian		Harrisburg	1,682	-			
		SCIO	137,258	2,520			
		PENNY	13,232	46,567			
		PENNY & FULMER VALLEY	42,660	71,003			
		RICHBURG	4,057,637	3,121,677			
		RICHBURG-WAUGH & PORTER	1,104	3,240			
		Canadaway PERRYSBURG	-	395			
		BRADFORD THIRD	228,582	112,002			
		CLARKSVILLE	39,387	36,864	PERRYSBURG	2,055,287	4,746,392
		WAUGH & PORTER	42,100	247,245			
		FULMER VALLEY	1,745,218	4,349,886			
		Nunda	-	-			
		RHINESTREET	-	3,409			
		TULLY	1,108	275,643	TULLY	1,108	275,643
		HAMILTON	-	20,416	HAMILTON	-	20,416
	Middle	MARCELLUS	-	747,399	MARCELLUS	-	747,399
		ONONDAGA	647,251	25,843,114	ONONDAGA	647,251	25,843,114
		ONONDAGA-ORISKANY	-	223,157			
		ORISKANY	10,582	31,738,725	ORISKANY	10,582	31,961,882
	Lower	HELDERBERG	-	10,230,425	HELDERBERG	-	10,230,425
		ONONDAGA-BASS ISLAND	532,310	3,118,389			
		BASS ISLAND	1,021,802	5,739,620	BASS ISLAND	1,580,509	9,416,091
		BASS ISLAND/MEDINA	26,397	558,082			
		AKRON	1,577	1,729,358	AKRON	1,577	1,729,358
		SALINA	1,278	5,778			
		CAMILLUS	-	60			
	Upper	SYRACUSE	570	2,338			
		VERNON	-	358,405			
		CLINTON	-	87,231			
		LOCKPORT	-	69,528			
Silurian		ROCHESTER SHALE	-	70,693			
		SAUQUOIT	-	210			
		SODUS SHALE	-	164,071			
		MEDINA	213,688	514,545,705			
		GRIMSBY	-	1,501,854	MEDINA	213,688	521,205,687
		WHIRLPOOL	-	893,326			
	Lower	MEDINA-QUEENSTON	-	4,264,802			
		HERKIMER	-	5,849,567			
		HERKIMER-ONEIDA	-	1,178,375			
		ONEIDA	-	1,024,647	HERKIMER-ONEIDA-OSWEGO	-	9,169,025
		ONEIDA-OSWEGO	-	1,094,384			
		QUEENSTON	-	56,439,648	QUEENSTON	-	56,439,648
	Upper	OSWEGO	-	22,052			
Ordovician		UTICA	-	-			
	Middle	TRENTON	-	485,477	TRENTON	-	485,477
		BLACK RIVER	-	318,316,063	BLACK RIVER	-	318,316,063
		LITTLE FALLS	-	501,440	LITTLE FALLS	-	501,440
Cambrian	Upper	THERESA	-	3,588,222	THERESA	-	3,588,222
		POTSDAM	-	-			

NYS Oil & Gas Data Summary 1967-2010, compiled by Briana Mordick, NRDC, December 2011.

Using the Marcellus Shale impact assessment and proposed mitigation measures as a surrogate for peak and cumulative impact assessment in the Utica and all other unnamed low-permeability formations is an inadequate approach.

For example, the Utica Shale Gas Reservoir is almost twice as deep as the Marcellus Shale Gas Reservoir. The Utica Shale dips to 9,000' deep,[8] while the Marcellus Shale is approximately 5,000' deep.[9] Utica Shale wells will take longer to drill than Marcellus Shale wells, generating more air pollution and drilling waste, HVHF waste and resulting in longer duration surface impacts (e.g. noise, light, fuel and chemical storage periods, etc.). Additionally, waste generated translates into additional transportation and surface use impacts. Utica Shale development will also require more resources and equipment. Deeper shale gas formations will have higher reservoir pressure, and will penetrate more known oil and gas zones before reaching the Utica Shale, meaning increased blowout risk. Higher reservoir pressure will require additional combustion equipment to meet higher pump pressure and energy demands. Deeper wells can have more complex well construction designs. Fully cemented casing strings will be more difficult to complete at deeper depths and higher temperature cement mixtures will be required if subsurface temperatures exceed 200 ^{0}F. Therefore, the maximum impact assessment for a Marcellus Shale well is not sufficient to examine the maximum impact of a Utica Shale well.

Additionally, there is little information in Petroleum Engineering technical literature on the Utica Shale, and how it may be effectively developed. The 2011 RDSGEIS assumes that the Utica Shale will be developed using the same exact techniques as the Marcellus Shale; however, this may not be the case. For example, a 2007 a paper prepared by Universal Well Services Inc., CESI Chemical A Flotek Industries Co., in collaboration with the State University of New York noted some significant differences in the Utica Shale, and the likelihood for a unique stimulation method:

> *The primary purpose of stimulating fractured shale reservoirs is the extension of the drainage radius via creation of a long fracture sand pack that interconnects with natural fractures thereby establishing a flow channel network to the wellbore.* ***However, there is limited understanding of a successful method capable of stimulating Utica Shale reservoirs. Indeed most attempts to data have yielded undesirable results****. This could be due to several factors, including formation composition, entry pressure, and premature pad fluid leak-off. Furthermore, stimulation of Utica shale reservoirs with acid alone has not been successful. This treatment method leads to a fracture length and drainage radius less than expected resulting in poor well productivity [emphasis added].*[10]
>
> *…several recently drilled Utica shale wells have not responded well to the normal shale fracturing practices.* ***An understanding of Utica shale mineralogy and rock mechanics is necessary before a stimulation method and fluid are selected*** *[emphasis added].*[11]

Additionally, the authors point out that the Utica, unlike the Marcellus, contains a high percentage of acid soluble carbonate and dolomite that may require chemical treatment (e.g. acids) to treat the carbonates and dolomite to reduce entry pressures. They suggest that an acid stimulation treatment could potentially be the main stimulation method instead of a HVHF, or alternatively be added as an additional pre-

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[8] 2009 NYSDEC, DSGEIS, Page 4-5.

[9] 2009 NYSDEC, DSGEIS, Page 4-14.

[10] Paktinat, J., Pinkhouse, J.A., and Fontaine, J., (Universal Well Services Inc.), Lash, G. G., State University of New York College at Fredonia, Penny, G.S., CESI Chemical A Flotek Industries Co., Investigation of Methods to Improve Utica Shale Hydraulic Fracturing in the Appalachian Basin, Society of Petroleum Engineers, SPE Paper 111063, 2007, Page 1.

[11] Paktinat, J., Pinkhouse, J.A., and Fontaine, J., (Universal Well Services Inc.), Lash, G. G., State University of New York College at Fredonia, Penny, G.S., CESI Chemical A Flotek Industries Co., Investigation of Methods to Improve Utica Shale Hydraulic Fracturing in the Appalachian Basin, Society of Petroleum Engineers, SPE Paper 111063, 2007, Page 2.

treatment to a HVHF. The Utica also contains a higher percentage of clays than the Marcellus, and has the potential to generate both siliceous and organic fines that may require additional chemical treatment.

Moreover, there are low-permeability gas reservoirs that are present at depths shallower than the Marcellus Shale, which were not studied at all. Those unnamed, unanalyzed low-permeability reservoirs are in closer proximity to protected water resources, and warrant a complete technical and scientific assessment. Most importantly, HVHF modeling and fracture design requirements should be established to ensure that man-made induced fractures in these shallower reservoirs do not propagate in a manner that pollutes protected groundwater resources. Man-made induced fractures in shallower formations will tend to propagate on the horizontal plane; however, the size of that horizontal fracture must be constrained so that it does not intersect with existing improperly constructed or improperly abandoned wells or transmissive faults and fractures that can provide a direct pollution pathway to protected groundwater resources.

Best technology and best practices and cumulative impacts, in many cases, are reservoir specific. Because the RDSGEIS does not contain information on the depth, type, activity, or equipment requirements for the general category called "***other*** *low-permeability gas reservoirs*," it is not possible to determine if the maximum impact assessment for a Marcellus Shale well sufficiently covers the maximum impact from "***other*** *low-permeability gas reservoirs.*" Nor is it possible to determine whether best technology and best practices developed for the Marcellus Shale would apply to the Utica Shale since there is very little information and understanding of the optimal Utica Shale stimulation method at this time.

> **Recommendation No. 1**: The SGEIS should either include additional information and analysis on the impacts of exploring and developing the Utica Shale and other unnamed low-permeability gas reservoirs, or acknowledge that there is insufficient information and analysis to study the impacts of this development. In the latter case, the SGEIS should conclude that its examination of impacts and mitigation measures is limited to the Marcellus Shale Gas Reservoir, and therefore any Utica Shale or other unnamed low-permeability gas reservoir development will warrant a site-specific supplemental environmental impact statement review or should be covered under another, future SGEIS process.

3. Liquid Hydrocarbon Impacts (Oil and Condensate)

Background: NYS 2009 Annual Oil and Gas Report[12] show that NYS produced 323,536 barrels of oil in 2009, primarily from the western counties of:

Cattaraugus	201,688 barrels
Allegany	47,421 barrels
Chautauqua	40,187 barrels
Steuben	9,992 barrels

NYSDEC did not separately report the amount of condensate or natural gas liquids production.

Chapter 2 of this report includes a table summarizing oil and gas production from 1967 to 2010 in NYS, showing that oil gas been produced from above the Marcellus and Utica Shale formations, verifying the potential to encounter liquid hydrocarbons while drilling into the Marcellus and Utica formations.

2011 RDSGEIS: The 2011 RDSGEIS describes natural gas exploration and production, but does not address the potential for shale gas wells to also encounter liquid hydrocarbons. Natural gas exploration can identify oil and condensate development opportunities. If liquid hydrocarbons are found while drilling a shale gas well, additional wells and drillsites may be needed to develop those oil resources.

Liquid hydrocarbons found during natural gas exploration have the potential to contaminate the environment through spills and well blowouts. The risk of oil spills during shale gas exploration has not been analyzed in the RDSGEIS. While blowouts are infrequent, they do occur, and are a reasonably foreseeable consequence of exploratory drilling operations. Blowouts can occur from gas and/or oil wells. They can last for days, weeks, or months until well control is achieved. On average, a blowout occurs in 7 out of every 1,000 onshore exploration wells. [13] Two recent gas well blowouts occurred in Pennsylvania due to Marcellus Shale drilling.[14,15]

The 2011 RDSGEIS provided several useful maps and a stratigraphic section that aid in understanding the overlap of NYS' oil and gas production intervals. Figure 4.2 includes a Stratigraphic Section of Southwestern NYS that shows oil is produced from the Upper Devonian, at shallower depths than the Marcellus Shale, meaning that wells drilled in this region may encounter oil before penetrating the Marcellus. An annotated version of Figure 4.2 is also shown in Chapter 2 of this report. Figures 4.8 and 4.9 indicate that there is an overlap of current oil production with possible Marcellus Shale development in Cattaraugus, Allegany, Chautauqua, and Steuben counties.

Oil is also found below the Marcellus Shale and above the Utica Shale in the Upper Silurian. Therefore wells drilled into the Utica Shale may encounter oil before penetrating the Utica. Figure 4.6 indicates that there is an overlap of current oil production with possible Utica Shale development in Steuben County.

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[12] New York State Oil, Gas and Mineral Resources, 26th Annual Report for Year 2009 and Appendices, Prepared by NYSDEC, 2009.

[13] Rana, S., Environmental Risks- Oil and Gas Operations Reducing Compliance Cost Using Smarter Technologies, Society of Petroleum Engineering Paper 121595-MS, Asia Pacific Health, Safety, Security and Environment Conference, 4-6 August 2009, Jakarta, Indonesia, 2009.

[14] Blowout Occurs at Pennsylvania Gas Well, Wall Street Journal, June 4, 2010.

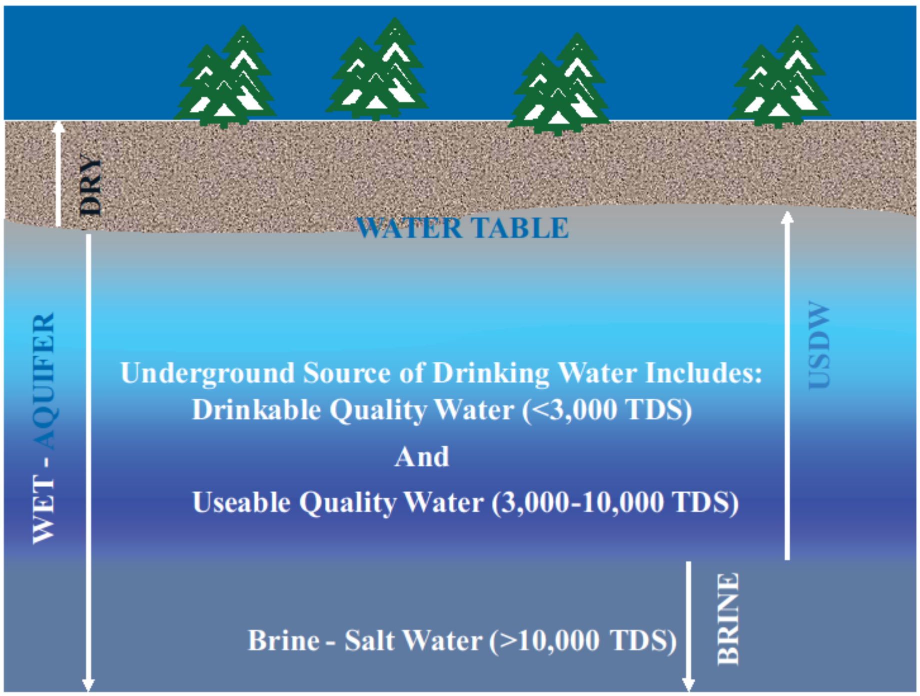
[15] Pennsylvania Fracking Spill: Natural Gas Well Blowout Spills Thousands of Gallons of Drilling Fluid, The Huffington Post, April 20, 2011.

There are low-permeability gas reservoirs that are present at depths both shallower and deeper than the Marcellus Shale, which were not studied in detail in the RDSGEIS. Absent geologic maps for these unnamed, unanalyzed low-permeability reservoirs, it is not clear where oil development and shale gas development overlap for these reservoirs may occur.

Recommendation No. 2: The SGEIS should examine the potential for shale gas wells to also encounter liquid hydrocarbons. The SGEIS should also examine the incremental risks of oil well blowouts and oil spills, as well as the impacts from the additional wells and drillsites that may be required to develop oil resources identified by shale gas exploration and production activities.

4. Water Protection Threshold

Background: The regulations promulgated under the federal Safe Drinking Water Act (SDWA) define an Underground Source of Drinking Water (USDW) as an aquifer or part of an aquifer, which is not exempted (per 40 CFR § 146.4), and: (1) which supplies a public water system; or (2) which contains a sufficient quantity of groundwater to supply a public water system and either supplies drinking water for human consumption or contains fewer than 10,000 milligrams/liter of Total Dissolved Solids (TDS) [10,000 ppm TDS]. 40 CFR § 144.3. An EPA diagram depicting a USDW is shown below.[16]



The 2011 RDSGEIS: The 2011 RDSGEIS is based on the protection of potable water as defined as water containing less than 250 ppm of sodium chloride or 1,000 ppm TDS. The RDSGEIS states:

> *For oil and gas regulatory purposes, **potable fresh water is defined as water containing less than 250 ppm of sodium chloride or 1,000 ppm TDS** and salt water is defined as containing more than 250 ppm sodium chloride or 1,000 ppm TDS [emphasis added].*[17]

The RDSGEIS identifies 850' as the depth where 250 ppm of sodium chloride or 1,000 ppm TDS is typically reached, however the RDSGEIS notes that in some cases potable water is found deeper than 850'.

[16] USEPA, Karen Johnson, Chief Ground Water & Enforcement Branch, 2010 PowerPoint Presentation, EPA's Underground Injection Control Program, Regulation of Disposal Wells in Pennsylvania.

[17] 2011 NYSDEC, RDSGEIS, Page 2-23.

> ***<u>Groundwater from sources below approximately 850 feet in New York typically is too saline for use as a potable water supply; however, there are isolated wells deeper than 850 feet that produce potable water</u>*** *and wells less than 850 feet that produce salt water. A depth of 850 feet to the base of potable water is commonly used as a practical generalization for the maximum depth of potable water; however, a variety of conditions affect water quality, and the maximum depth of potable water in an area should be determined based on the best available data [emphasis added].*[18]

By comparison, USDWs are based on a TDS cutoff of 10,000 ppm. The RDSGEIS has not explained why it proposes, and NYS regulations rely on, a 1,000 ppm TDS threshold instead of the federally required USDW threshold of 10,000 ppm TDS.

Ohio issued updated Oil and Gas Well Construction Rules on October 28, 2011, that require surface casing and intermediate casing to be set to protect the deepest underground source of drinking water (USDW); Ohio's rules are based on the 10,000 ppm federal TDS threshold.[19]

Recommendation No. 3: The SGEIS and the NYCRR should require wells to be constructed to protect Underground Sources of Drinking Water (USDWs), as defined by the Safe Drinking Water Act.

NYS' use of a 1,000 ppm TDS cut-off instead of the USDW threshold of 10,000 ppm TSD is a two-fold problem: First, the RDSGEIS states that surface casing ("water protection piping") setting depths will be 925' if no other data is available.[20] The 925' surface casing setting depth is based on an 850' base plus 75'[21], where NYSDEC has assumed that TDS will exceed 1,000 ppm at deeper than 850'. The 925' casing setting depth does not take into account the fact that drinking water, under the SDWA definition of a USDW, could exist at depths below 850'. Therefore the RDSGEIS has not provided scientific justification for the default 925' casing setting depth, nor has it explained how such a proposal comports with federal law.

Second, the entire RDSGEIS is premised on the conclusion that a HVHF well initiated at a depth of 2,000' would be safe, because NYSDEC assumes that NYS does not have any drinking water resources deeper than 850' deep. However, the RDSGEIS does not indicate that any examination of the depth of 10,000 ppm TDS water or of the availability of drinking water resources below 850' has been or will be conducted and, therefore, cannot support its 850' assumption.

Additionally, the RDSGEIS states that potable water is found deeper than 850'. Therefore, the 2,000' threshold depth for initiating a HVHF under this SGEIS requires re-evaluation. And as explained in Chapter 10 of this report, HCLLC is recommending that initial drilling and completions occur below 4,000', while site-specific data is gathered in NYS to justify safe drilling at shallower depths.

[18] 2011 NYSDEC, RDSGEIS, Page 2-23.

[19] Proposed Ohio Oil and Gas Well Construction Rules, October 28, 2011, currently under public review and comment.

[20] 2011 NYSDEC, RDSGEIS, Page 7-50.

[21] See Chapter 6 of this report, where a 100' buffer is recommended, instead of 75'.

Recommendation No. 4: The SGEIS should re-examine the 925' casing default setting and the 2000' HVHF cut-off, and justify how these proposed thresholds will protect USDW sources. Protecting to a 10,000 ppm TDS standard will likely increase both depths.

The SGEIS should include data on the location of Underground Sources of Drinking Water (USDWs), as defined by the Safe Drinking Water Act, across NYS. The SGEIS should include USDW maps for all areas that will be affected by the proposed scope of the SGEIS. This data will be an important tool for industry and the public alike to ensure USDWs are protected.

NYCRR Proposed Revisions: Well construction regulations at 6 NYCRR § 550-559 instruct operators to construct oil and gas wells in a manner that protects potable fresh water, i.e., only water containing less than 250 ppm of sodium chloride or less than 1,000 ppm of TDS. 6 NYCRR § 550.3 (ai).

The NYCRR does not protect, under its definition of "potable fresh water," water resources with less than 10,000 ppm TDS but greater than 1,000 ppm TDS, which could qualify as USDWs under the Safe Drinking Water Act. See 40 CFR §§ 144.3, 146.4.

Regulations at 6 NYCRR § 554.1 require operators to prevent pollution to "surface or ground fresh water"; however, this term is not defined by the NYCRR, so it is unclear what additional groundwater beyond "potable fresh water" would be protected or how.

Recommendation No. 5: The NYCRR should be consistent with federal law [Underground Sources of Drinking Water (USDWs)] or NYSDEC should propose more protective standards for NYS if needed to protect NYS' future water supply needs, if the federal threshold is found insufficient.

5. Conductor Casing

Background: In 2009, HCLLC recommended the NYCRR and the SGEIS be revised to include conductor casing construction standards. While a number of changes were made to improve conduct casing requirements in the RDSGEIS, the proposed revisions to the NYCRR do not include conductor casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on conductor casing and the technical basis for HCLCC's recommendations.

Conductor casing construction standards are only partially addressed in the 2011 RDSGEIS, under Appendix 10, Proposed Supplementary Permit Conditions for HVHF, and Appendix 9, Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers**.**

2011 RDSGEIS: The 2011 RDSGEIS Appendix 9, Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers, includes a conductor casing requirement that limits drilling fluid types. The requirement excludes synthetic muds and oil based muds from being used while drilling shallow sections of the wellbore.

> *Any hole drilled for conductor or surface casing (i.e., "water string") must be drilled on air, fresh water, or fresh water mud. For any holes drilled with mud, techniques for removal of filter cake (e.g., spacers, additional cement, appropriate flow regimes) must be considered when designing any primary cement job on conductor and surface casing.*

Excluding synthetic muds and oil based muds from being used while drilling shallow sections of the wellbore is a best practice.

Appendix 9 also includes procedures for ensuring conductor pipe is cemented from top to bottom, and firmly affixed in a central location in the wellbore, with a continuous, equally thick layer of cement around the pipe.

> *If conductor pipe is used, it must be run in a drilled hole and it must be cemented back to surface by circulation down the inside of the pipe and up the annulus, or installed by another procedure approved by this office. Lost circulation materials must be added to the cement to ensure satisfactory results.*
>
> *Additionally, at least two centralizers must be run with one each at the shoe and at the middle of the string. In the event that cement circulation is not achieved, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. In lieu of or in combination with such grouting or squeezing from the surface, this office may require perforation of the conductor casing and squeeze cementing of perforations. This office must be notified _______ hours prior to cementing operations and cementing cannot commence until a state inspector is present.*

The 2011 RDSGEIS Appendix 10, Proposed Supplementary Permit Conditions for HVHF, includes a conductor casing condition that states:

> *When drive pipe (conductor casing) is left in the ground, a pad of cement shall be placed around the well bore to block the downward migration of surface pollutants. The pad shall be three feet square or, if circular, three feet in diameter and shall be crowned up to the drive pipe (conductor casing), unless otherwise approved by the Department.*

NYCRR Proposed Revisions: In summary, NYSDEC has included important conductor casing construction guidelines in the 2011 RDSGEIS for wells drilled in primary and principal aquifer areas and HVHF wells, but has not proposed to codify those changes in the NYCRR.

The conductor casing construction guidelines listed in the 2011 RDSGEIS should apply to all wells in NYS, and should not just be limited to wells drilled in primary and principal aquifer areas and HVHF wells. These are best practices for construction of all oil and gas wells.

NYSDEC should set a conductor casing depth criterion, requiring conductor casing be set to a sufficient depth to provide solid structural anchorage. Also, the regulations should specify that conductor casing design be based on site-specific engineering and geologic factors.

Recommendation No. 6: Conductor casing requirements listed in the Proposed Supplementary Permit Conditions for HVHF and Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers should be codified in the NYCRR and should apply to all wells drilled in NYS, not just HVHF wells. Additionally, NYSDEC should set a conductor casing depth criterion, requiring conductor casing be set to a sufficient depth to provide a solid structural anchorage. Regulations should specify that conductor casing design be based on site-specific engineering and geologic factors.

6. Surface Casing

Background: In 2009, HCLLC recommended the NYCRR be revised to include additional surface casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on surface casing the technical basis for HCLCC's recommendations.

Surface casing plays a very important role in protecting groundwater aquifers, providing the structure to support blowout prevention equipment, and providing a conduit for drilling fluids while drilling the next section of the well.

The drilling engineer determines the depth of surface casing installation with these key factors in mind: surface casing should stop above any significant pressure or hydrocarbon zone, ensuring the blowout preventer can be installed prior to drilling into a pressure or hydrocarbon zone, and surface casing should provide a protective barrier to prevent hydrocarbons from contaminating aquifers when the well is drilled deeper (below the surface casing) into hydrocarbon bearing zones.

Stray gas may impact ground water and surface water from poor well construction practices. Properly constructed and operated oil and gas wells are critical to mitigating stray gas and thereby protecting water supplies and public safety. If a well is not properly cased and cemented, natural gas in subsurface formations may migrate from the wellbore through bedrock and soil. Stray gas may adversely affect water supplies, accumulate in or adjacent to structures such as residences and water wells, and has the potential to cause a fire or explosion.

Instances of improperly constructed wellbores leading to the contamination of drinking water with natural gas are well documented in Pennsylvania.[22] Gas well leaks from improperly constructed gas wells have resulted in contamination of the Susquehanna River and adjacent private water supply wells.[23] A 2011 Duke University study covering Pennsylvania and New York found methane contamination of drinking water associated with shale-gas extraction. Duke University found that methane concentrations were 17 times higher, on average, in drinking water wells in active drilling and extraction areas than in wells in nonactive areas.[24]

The 2011 RDSGEIS and the proposed revisions to the NYCRR include important improvements for surface casing. Overall, NYS' surface casing requirements are fairly robust when the NYCRR, guidance documents, and standard stipulations are combined. NYSDEC proposed a number of substantial improvements in the surface casing requirements, most notably improved cement quality, casing quality, and installation techniques.

This chapter reviews the proposed changes and supports the improvements that have been made. It also makes suggestions for improved regulatory clarity and adds a few additional recommendations for NYSDEC to consider in completing its surface casing regulatory program revision.

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[22] *See, e.g.*, DEP Reaches Agreement with Cabot to Prevent Gas Migration, Restore Water Supplies in Dimock Township, Agreement Requires DEP Approval for Well Casing, Cementing, November 4, 2009, available at http://www.portal. state.pa.us/portal/server.pt/community/newsroom/14287?id=2418& typeid=1.

[23] *See, e.g.*, DEP Monitors Stray Gas Remediation in Bradford County Requires Chesapeake to Eliminate Gas Migration, Chesapeake Commits to Evaluate, Remediate All PA Wells to Conform with Improved Casing Regulations, September 17, 2010, available at http://www.portal.state.pa.us/portal/server.pt/ community/newsroom/14287?id=14274&typeid=1.

[24] Osborn, S.G., A. Vengosh, N.R. Warner, R.B. Jackson, 2011 Methane contamination of drinking water accompanying gas- well drilling and hydraulic fracturing, Proceedings of the National Academy of Sciences, U.S.A.; DOI: 10.1073/pnas.1100682108, Page 2.

The main recommendation in this section is to streamline surface casing regulations by amending the NYCRR to include requirements contained in the 2011 RDSGEIS and standard stipulations. As proposed, NYSDEC has included a number of surface casing requirements in the 2011 RDSGEIS at Appendices 8, 9, and 10 (Proposed Permit Conditions). NYSDEC also included some, but not all, of these requirements in the NYCRR. Unfortunately, there are a number of inconsistencies between the permit conditions and the NYCRR that create uncertainty about what will be required.

Additionally, there are a number of new surface casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. These requirements should be included in the NYCRR Part 554 (drilling practices for all oil and gas wells), and not just contained in NYCRR Part 560 (drilling practices for HVHF wells).

In 2009, HCLLC recommended that improved casing and cementing practices be codified in the NYCRR, rather than through a combined patchwork of permit conditions and regulations. HCLLC's concern was that the proposed requirements, in a number of cases, were inconsistent with existing regulations, and could be more efficiently consolidated into a single, more concise set of regulations.

NYSDEC's consultant Alpha Geoscience disagreed. Alpha Geoscience concluded that it would be more logical to use a patchwork of regulations, add a long list of conditions to each permit, and forgo regulatory revision.

> *Harvey Consulting suggests that NYSDEC revise the NYS oil and gas regulations to specifically address new casing and cementing practices and fresh water aquifer supplementary permit conditions. The purpose of the SGEIS, however, is not to revise regulations. The purpose of the Proposed Supplementary Permit Conditions for shale gas activities is to customize the existing regulations and guideline framework to fit new and changing industry, relieving the need for frequent regulatory changes. Permit conditions must be met by the party seeking a permit for a proposed action, so whether or not the permit conditions are included in the New York State regulations is irrelevant.*[25]

HCLLC disagrees with Alpha Geoscience's recommendation. It is relevant whether new requirements are found in regulation or a permit condition. Foremost, revising the outdated NYCRR provides simplicity and clarity for industry and the public. It provides a concise set of co-located rules. Conversely, layering a complex patchwork of permit conditions on outdated NYCRR creates confusion, inconsistency, and enforcement challenges. Furthermore, permit conditions can be revised and modified by staff, without public review, and can be applied in a more discretionary manner. Regulations are not discretionary, and are not subject to modification without a formal public review process. Therefore, HCLLC recommends that requirements that apply to all wells be codified in the NYCRR, and permit conditions be reserved for site-specific, project-specific requirements. This will improve clarity and certainty for industry and the public alike, and will afford NYSDEC the opportunity to apply site-specific, project specific requirements to address unique project issues.

NYSDEC evidently agreed with HCLLC's recommendation to revise the NYCRR by proposing revisions for public review; however, the regulations have only been partially updated to include new surface casing best practices. Therefore inconsistency remains, and needs resolution.

Recommendation No. 7: The surface casing and cementing requirements should be consistent throughout the SGEIS text and with the NYCRR.

[25] Alpha Geoscience, Review of the DSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA on January 20, 2011, Page 13.

An analysis of the proposed RDSGEIS conditions found in Appendices 8, 9, and 10 is provided below and compared to the proposed NYCRR revisions. Recommendations are made to improve consistency in the documents and highlight additional best practices that should be considered.

The 2011 RDSGEIS: It appears that NYSDEC's intent is to require that all wells meet the minimum standards found at Appendix 8 (NYSDEC's Casing and Cementing Practices), and then layer on additional requirements for wells drilled in primary and principal aquifers (Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers). It appears that a third layer of requirements will be applied to wells that undergo HVHF stimulation treatments (Appendix 10 Proposed Supplementary Permit Conditions for HVHF).

Therefore, it is assumed that a shale gas well that is drilled in a primary and principal aquifer, and will undergo a HVHF stimulation treatment must meet all the conditions found in Appendices 8, 9, and 10; however, this would not be possible because the permit conditions are discordant. An evaluation of these layered conditions reveals inconsistencies, as explained in the text and summary table below.

The 2011 RDSGEIS Appendix 8: Appendix 8 Casing and Cementing Practices requires: surface casing be set at least 75' below freshwater or at least 75' into bedrock, whichever is deeper; surface casing be set before hydrocarbons are encountered; new pipe be used (or used pipe if tested); and centralizers and cement baskets be used.

2. *Surface casing shall extend at least 75 feet beyond the deepest fresh water zone encountered or 75 feet into competent rock (bedrock), whichever is deeper, unless otherwise approved by the Department. However, the surface pipe must be set deeply enough to allow the BOP [blow-out preventer] stack to contain any formation pressures that may be encountered before the next casing is run.*

3. *Surface casing shall not extend into zones known to contain measurable quantities of shallow gas. In the event that such a zone is encountered before the fresh water is cased off, the operator shall notify the Department and, with the Department's approval, take whatever actions are necessary to protect the fresh water zone(s).*

4. *All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi), unless otherwise approved. Used casing may be approved for use, but must be pressure tested before drilling out the casing shoe or, if there is no casing shoe, before drilling out the cement in the bottom joint of casing. If plain end pipe is welded together for use, it too must be pressure tested. The minimum pressure for testing used casing or casing joined together by welding, shall be determined by the Department at the time of permit application. The appropriate Regional Mineral Resources office staff will be notified six hours prior to making the test. The results will be entered on the drilling log.*

5. *Centralizers shall be spaced at least one per every 120 feet; a minimum of two centralizers shall be run on surface casing. Cement baskets shall be installed appropriately above major lost circulation zones.*[26]

Appendix 8 requires the use of: 25% excess cement, spacer fluids between the drilling muds and cement, and lost circulation additives. Appendix 8 also requires that gas flows or lost circulation be addressed and

[26] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 1.

the hole be conditioned before cementing. NYSDEC reserves the right to require a cement evaluation log if cement does not return to the surface.

6. *Prior to cementing any casing strings, all gas flows shall be killed and the operator shall attempt to establish circulation by pumping the calculated volume necessary to circulate. If the hole is dry, the calculated volume would include the pipe volume and 125% of the annular volume. Circulation is deemed to have been established once fluid reaches the surface. A flush, spacer or extra cement shall be used to separate the cement from the bore hole spacer or extra cement shall be used to separate the cement from the bore hole fluids to prevent dilution. If cement returns are not present at the surface, the operator may be required to run a log to determine the top of the cement.*

7. *The pump and plug method shall be used to cement surface casing, unless approved otherwise by the Department. The amount of cement will be determined on a site-specific basis and a minimum of 25% excess cement shall be used, with appropriate lost circulation materials, unless other amounts of excesses are approved or specified by the Department.* [27]

Appendix 8 requires: the water used in the cement be tested for pH and temperature; the cement be prepared according to manufacturer specifications; and the cement be allowed to harden to a compressive strength of at least 500 psi before being disturbed.

8. *The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing ticket.*

9. *The cement slurry shall be prepared according to the manufacturer's or contractor's specifications to minimize free water content in the cement.*

10. *After the cement is placed and the cementing equipment is disconnected, the operator shall wait until the cement achieves a calculated compressive strength of 500 psi before the casing is disturbed in any way. The waiting-on-cement (WOC) time shall be recorded on the drilling log.*[28]

The 2011 RDSGEIS Appendix 9: Appendix 9, Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers, applies to wells drilled in primary and principal aquifer zones. Appendix 9 includes conditions that require: surface casing to be set at least 100’ below the deepest freshwater zone and at least 100’ into bedrock; the annulus be at least 1-1/4” wide to optimize cement placement and cement sheath width: the entire annulus be cemented, using at least 50% excess cement; the cement design include additives to control lost circulation; centralizers be run at least every 120’; new pipe be used (or reconditioned tested pipe); and NYSDEC be notified and present for cementing operations.

[27] 2011 NYSDEC, RDSGEIS, Appendix 8, Pages 1-2.

[28] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 2.

> *A surface casing string must be set at least 100' below the deepest fresh water zone and at least 100' into bedrock. If shallow gas is known to exist or is anticipated in this bedrock interval, the casing setting depth may be adjusted based on site-specific conditions provided it is approved by this office. There must be at least a 2½" difference between the diameters of the hole and the casing (excluding couplings) or the clearance specified in the Department's Casing and Cementing Practices, whichever is greater. Cement must be circulated back to the surface with a minimum calculated 50% excess. Lost circulation materials must be added to the cement to ensure satisfactory results. Additionally, cement baskets and centralizers must be run at appropriate intervals with centralizers run at least every 120'. Pipe must be either new API graded pipe with a minimum internal yield pressure of 1,800 psi or reconditioned pipe that has been tested internally to a minimum of 2,700 psi. If reconditioned pipe is used, an affidavit that the pipe has been tested must be submitted to this office before the pipe is run. This office must be notified _______ hours prior to cementing operations and cementing cannot commence until a state inspector is present.*[29]

Appendix 9 requires the surface hole be drilled using compressed air or Water-Based Muds (WBM), meaning no Synthetic-Based Muds (SBM) or Oil-Based Muds (OBM) may be used.

> *Any hole drilled for conductor or surface casing (i.e., "water string") must be drilled on air, fresh water, or fresh water mud. For any holes drilled with mud, techniques for removal of filter cake (e.g., spacers, additional cement, appropriate flow regimes) must be considered when designing any primary cement job on conductor and surface casing.*[30]

As found in Appendix 9, freshwater zone depths and the potential for shallow gas hazards must be estimated and documented in drilling applications; actual data must be collected during drilling to identify any freshwater zones and shallow gas hazards that require additional NYSDEC review and approval.

> *If multiple fresh water zones are known to exist or are found or if shallow gas is present, this office may require multiple strings of surface casing to prevent gas intrusion and/or preserve the hydraulic characteristics and water quality of each fresh water zone. The permittee must immediately inform this office of the occurrence of any fresh water or shallow gas zones not noted on the permittee's drilling application and prognosis. This office may require changes to the casing and cementing plan in response to unexpected occurrences of fresh water or shallow gas, and may also require the immediate, temporary cessation of operations while such alterations are developed by the permittee and evaluated by the Department for approval.* [31]

Appendix 9 requires cement fill the surface casing annulus, and if cement placement in the annulus is not initially successful, additional cement must be pumped into the annulus until it is filled with cement.

> *In the event that cement circulation is not achieved on any surface casing cement job, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. This office must be notified _______ hours prior to cementing operations and cementing cannot commence until a state inspector is present. In lieu of or in*

[29] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 1.

[30] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 1.

[31] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

> *combination with such grouting or squeezing from the surface, this office may require perforation of the surface casing and squeeze cementing of perforations.* [32]

In Appendix 9, NYSDEC reserves the right to require the operator to run a cement bond log; however, it does not require one to verify the integrity of all surface casing cement jobs.

> *This office may also require that a cement bond log and/or other logs be run for evaluation purposes. In addition, drilling out of and below surface casing cannot commence if there is any evidence or indication of flow behind the surface casing until remedial action has occurred. Alternative remedial actions from those described above may be approved by this office on a case-by-case basis provided site-specific conditions form the basis for such proposals.*[33]

The 2011 RDSGEIS Appendix 10: Appendix 10 contains Proposed Supplementary Permit Conditions for HVHF operations, including additional surface casing requirements. The 2011 RDSGEIS does not explain why these additional pollution prevention and quality control/quality assurance (QC/QA) requirements do not apply to all oil and gas wells in NYS.

The 2011 RDSGEIS Appendix 10 requires new casing and the use of American Petroleum Institute (API) standards for: casing thread compounds, centralizer placement, and cement composition (including the requirement to use gas-blocking additives).

> *31) With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> > *a) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;*
> >
> > *b) Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);*
> >
> > *c) At least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);*
> >
> > *d) Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive…*[34]

[32] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

[33] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.

[34] 2011 NYSDEC, RDSGEIS, Appendix 10, Pages 5-6.

Appendix 10 also requires: drilling mud be circulated and conditioned prior to cementing; spacer fluid be used to separate the drilling mud from the cement, to avoid drilling mud contamination; and cement be installed using methods that inhibit voids in the cement.

> *e) Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond… The surface casing must be run and cemented immediately after the hole has been adequately circulated and conditioned.*
>
> *f) A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;*
>
> *g) The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus…*[35]

Appendix 10 establishes a specific period of time for the cement to harden, and a compressive strength standard that the cement must achieve before drilling continues deeper in the hole. This avoids disturbing the cement until it has completely set.

> *h) After the cement is pumped, the operator must wait on cement (WOC):*
>
> *1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and*
>
> *2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig.*[36]

Appendix 10 requires records be kept for a period of 5 years and be available to NYSDEC upon request.

> *A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.*[37]

[35] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.
[36] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.
[37] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

Appendix 10 reserves the right for NYSDEC to require additional casing strings to be set in the well if the surface casing fails to adequately protect water resources or poses a safety hazard.

> *38) The installation of an additional cemented casing string or strings in the well as deemed necessary by the Department for environmental and/or public safety reasons may be required at any time.*[38]

Appendix 10 requires NYSDEC's Casing and Cementing Practices be followed. NYSDEC's Casing and Cementing Practices are included in the 2011 RDSGEIS as Appendix 8. Yet, a number of the Casing and Cementing Practices found in Appendix 8 conflict with the new requirements in Appendix 10 for wells subject to HVHF.

The RDSGEIS does not provide a rationale or basis for the use of a 75' surface casing setting depth for some wells and a 100' surface casing setting depth for others. NYSDEC determined that a 100' setting depth is best practice for groundwater protection in areas of primary and principal aquifers, but does not explain why a 100' standard would not be best practice for all wells, or at least wells that undergo HVHF.

An analysis of the surface casing permit condition requirements and inconsistencies is provided in table format as Appendix A. Recommendations are listed in the table.

NYCRR Proposed Revisions: A number of the requirements listed in the RDSGEIS Appendices 8, 9, and 10 are not codified in the NYCRR, or conflict with the proposed changes to the NYCRR.

Listed below is an analysis of the proposed NYCRR revisions for surface casing and cementing. Specific recommendations for improving surface casing design, installation, and quality control/ quality assurance requirements are also included.

Surface Casing Setting Depth: 6 NYCRR § 554.1(d) requires that:

> *Surface casing shall be run in all wells to extend below the deepest potable fresh water level*.

Neither the 75' nor the 100' setting depths below the deepest protected water zone (described in the RDSGEIS) are specified in regulation. Furthermore, this regulation only protects "potable fresh water." As explained in Chapter 4 of this report, NYSDEC should consider its long-term water needs.

> **Recommendation No. 8**: 6 NYCRR § 554.1(d) should be revised to require the surface casing setting depth to be at least 100' below protected groundwater for all wells, or NYSDEC should provide a technical justification for reducing the setting depth to 75' for some wells.

Surface Casing Definition: 6 NYCRR § 550.3(au) reads:

> *Surface casing shall mean casing extending from the surface through the potable fresh water zone*.

This definition requires surface casing be set through only the protected water zone, and does not require the casing be set deeper. This definition, as written, does not include the important requirement for the casing to be set at least 100' below protected groundwater and be cemented in place.

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[38] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 8.

> **Recommendation No. 9**: 6 NYCRR § 550.3(au) should be revised to read: surface casing shall mean casing installed and cemented from the surface, through protected groundwater, to a point at least 100' below the deepest protected groundwater. Protected groundwater should be defined in a way that meets NYS' long-term water needs.

Rotary Tool Drilling Practices: 6 NYCRR § 554.4 should be revised to be consistent with the proposed RDSGEIS surface casing conditions, and remove reference errors. 6 NYCRR § 554.4(a) provides the operator with a choice of installing surface casing in accordance with 6 NYCRR § 554.1(b) (which does not provide specific instruction to the operator) or by cementing the production casing from below the deepest potable fresh water level to the surface (which does not provide specific instruction to the operator).

> *§554.4 Rotary tool drilling practices*
>
> *(a) On all wells where rotary tools are employed, and the subsurface formations and pressures to be encountered have been reasonably well established by prior drilling experience, the operator shall have the option of either running surface casing as provided in section 554.1(b) of this Part or of cementing the production casing from below the deepest potable fresh water level to the surface. In areas where the subsurface formations and pressures to be encountered are unknown or uncertain, surface casing shall be run as provided in section 554.1(b) of this Part.*

6 NYCRR § 554.1(b) does not provide any specific direction on the type or amount of surface casing to be installed; it just says:

> *Pollution of the land and/or of surface or ground freshwater resulting from exploration or drilling is prohibited.*

Nor does 6 NYCRR § 554.4(a) provide any specific direction on the type or amount of surface casing to be installed, other than to say that it must be set below *the deepest potable fresh water level,* but the minimum depth that the casing must be set below the deepest freshwater located is not specified.

> **Recommendation No. 10**: 6 NYCRR § 554.1(d) and 6 NYCRR § 554.4(a) should be combined or at least be consistent to require the surface casing setting depth to be at least 100' below protected groundwater.

NYCRR does not provide the operator with instructions on how to determine protected groundwater depth. The RDSGEIS explains that the depth of potable freshwater in NYS is typically 850' deep, but this depth will vary across the state. Using the 850' benchmark may not sufficiently protect all groundwater covered under the Safe Drinking Water Act. NYCRR should be revised to provide instructions to the operator on how to estimate protected water depth in drilling applications and well construction designs. NYCRR should require that depth be confirmed before setting surface casing.

> **Recommendation No. 11**: NYCRR should require the protected groundwater depth be estimated in the drilling application to aid in well construction design. NYCRR should require the protected water depth be verified with a resistivity log or other sampling method during drilling. If the protected water depth is deeper than estimated, an additional string of intermediate casing should be required. Additionally, the NYCRR needs to be clear on whether its purpose is to protect potable freshwater only, or a broader definition of protected groundwater, which would result in surface casing being set deeper.

6 NYCRR § 554.4(b) correctly requires: cement be placed by the pump and plug or displacement methods; cement be placed in the entire annulus; and a wait on cement time before further drilling. However, 6 NYCRR § 554.4(b) does not include the best practices listed in the permit conditions (Appendices 8 and 9). Additionally, many of the best practices included in Appendix 10 for HVHF wells should be included in regulations for all oil and gas wells.

Recommendation No. 12: 6 NYCRR § 554.4(b) should be revised to be consistent with the proposed Appendices 8 and 9 permit conditions. Also, the best practices listed in Appendix 10 for HVHF should apply to all oil and gas wells and be included in 6 NYCRR § 554.4(b).

Cable Tool Drilling Practices: 6 NYCRR § 554.3 includes requirements for cable tool drilling.

Recommendation No. 13: NYSDEC should verify whether cable tool drilling is still anticipated in NYS. If cable tool drilling is still allowed, 6 NYCRR § 554.3 should be revised to require these wells be constructed to the same quality standards as wells drilled with rotary drilling equipment.

Newly proposed surface casing regulations for HVHF wells at 6 NYCRR § 560.6(c)(10) require casing be run in accordance with the "department's casing and cementing requirements." Presumably this refers to the requirements set out in the RDSGEIS at Appendix 8, but this needs to be clarified. All surface casing requirements for HVHF operations should be codified in NYCRR.

A number of new requirements proposed at 6 NYCRR § 560.6(c)(10) should be applied to all wells in NYS, not just those that will undergo a HVHF treatment. 6 NYCRR § 560.6(c)(10) proposes to add these requirements only to HVHF wells.

> *(10) With respect to all surface, intermediate and production casing run in the well, and in addition to the department's casing and cementing requirements and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *(i) all casings must be new and conform to industry standards specified in the permit to drill;*
>
> *(ii) welded connections are prohibited;*
>
> *(iii) casing thread compound and its use must conform to industry standards specified in the permit to drill;*
>
> *(iv) in addition to centralizers otherwise required by the department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed (except production casing) and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill;*
>
> *(v) cement must conform to industry standards specified in the permit to drill and the cement slurry must be prepared to minimize its free water content in accordance with the industry standards and specifications, and contain a gas-block additive;*
>
> *(vi) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;*
>
> *(vii) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;*
>
> *(viii) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;*

(ix) after the cement is pumped, the operator must wait on cement (WOC) until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blowout preventer. The operator may request a waiver from the department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 pounds per square inch gage; and

(x) a copy of the cement job log for any cemented casing string in the well must be available to the department at the well site during drilling operations, and thereafter available to the department upon request. The operator must provide such log to the department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title. If the well is located on a multi-well pad, all cementing job logs must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title.

(11) The surface casing must be run and cemented as soon as practicable after the hole has been adequately circulated and conditioned.

The zone of critical cement (e.g. cement placed at bottom of surface casing, typically bottom 300-500') should achieve a 72-hour compressive strength standard of 1,200 psi and the free water separation for the cement should be no more than 6 ml per 250 ml of cement. For example, this requirement is found in the Pennsylvania surface casing code (25 PaCode § 78.85 (b))

An analysis of the proposed Appendices 8, 9, and 10 permit condition requirements and inconsistencies, with comparisons to NYCRR, is provided in table format as Appendix A. Recommendations for improving requirements and addressing inconsistencies are listed in the table.

Recommendation No. 14: The recommendations listed in the Surface Casing Analysis Table (Appendix A to this report) should be considered for the SGEIS and the NYCRR, including:

<u>Surface Casing Setting Depth</u>: NYSDEC should consider a 100' protection for all oil and gas wells. Additionally, NYSDEC needs to clarify whether this setting depth is intended to protect potable freshwater only, or include a broader definition of protected groundwater, which would result in deeper surface casing depths. This requirement should apply to all NYS wells.

<u>Protected Water Depth Verification</u>: The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method. If the actual protected water depth extends beyond the estimated protected water depth, an additional string of intermediate casing should be required. This requirement should apply to all NYS wells.

<u>Cement Sheath Width</u>: A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells.

Amount of Cement in Annulus: The surface casing annulus should be completely filled with cement; this should be clearly specified. There should be no void space in the annulus. This requirement should apply to all NYS wells.

Shallow Gas Hazards: If a shallow gas hazard is encountered, surface hole drilling must stop, and surface casing must be set and cemented, before drilling deeper into hydrocarbon resources. All oil and gas well designs and applications should plan for shallow gas hazards. Any shallow gas hazards encountered while drilling should be recorded. This requirement should apply to all NYS wells.

Excess Cement Requirements: 25% excess cement is standard practice, unless a caliper log is run to more accurately assess hole shape and required cement volume. This requirement should apply to all NYS wells.

Cement Type: The cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) is best practice. These practices should apply to all wells, not just HVHF wells.

Cement Mix Water Temperature and pH Monitoring: Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. This requirement should apply to all NYS wells, not just HVHF wells.

Lost Circulation Control: Lost circulation control is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Spacer Fluids: The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Hole Conditioning: Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Cement Installation and Pump Rate: The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice; this requirement should apply to all oil and gas wells, not just HVHF wells.

Rotation and Reciprocation: Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.

Centralizers: The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API RP 10D-2 (July 2010). This requirement should apply to all NYS wells, not just HVHF wells.

Casing Quality: New casing should be used in all wells. Once installed, surface casing remains in the well for the life of the well, and typically remains in place when the well is plugged and abandoned. It is important that the surface casing piping string (known as "the water protection piping string") is of high quality to maximize the corrosion allowance and life-cycle of the piping. The installation of older, used, thinner pipe, with less remaining corrosion allowance, may be a temporary solution, but not a long-term investment in groundwater protection. Used piping may pass an initial pressure test; however, it will not last as long as new piping, and will not be as protective of water resources in the long-term.

Casing Thread Compound: The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not HVHF wells.

Drilling Mud: The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all NYS wells.

Cement Setting Time: Best practice is to have surface casing strings stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells.

NYS Inspectors: Best practice is to have a state inspector on site during cementing operations, to verify surface casing cement is correctly installed, before attaching the blowout preventer and drilling deeper into the formation. This requirement should apply to all NYS wells.

Cement QA/QC: Circulating cement to the surface is one indication of successfully cemented surface casing, but it is not the only QA/QC check that should be conducted. Cement circulation to surface can be achieved even when there are mud or gas channels, or other voids, in the cement column. Circulating cement to the surface also may not identify poor cement to casing wall bonding. These integrity problems, among others, can be further examined using a cement evaluation tool and temperature survey.

Formation Integrity Test: It is best practice to complete a formation integrity test to verify the integrity of the cement in the surface casing annulus at the surface casing shoe. The test should be conducted after drilling out of the casing shoe, into at least 20 feet, but not more than 50 feet of new formation. The test results should demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the application for the Permit to Drill. This requirement should apply to all NYS wells.

BOP Installation: The Appendix 8 requirement is best practice. Additionally, the surface casing should be pressure tested to ensure it can hold the required working pressure of the BOP. This requirement should apply to all NYS wells.

Record Keeping: Best practice is to keep permanent records for each well, even after the well is plugged and abandoned (P&A'd). This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Additional Casing or Repair: NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.

Pressure Testing: Casing and piping should be pressure tested.[39]

[39] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, p. 109.

7. Intermediate Casing

Background: In 2009, HCLLC recommended the NYCRR be revised to include additional intermediate casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on intermediate casing and the technical basis for HCLCC's recommendations.

Intermediate casing provides a transition from the surface casing to the production casing. This casing may be required to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. A drilling engineer may set hundreds or thousands of feet of intermediate casing to: isolate unstable hole sections (to prevent collapse); isolate high or low pressure zones; isolate geologic "thief" zones prone to robbing mud from the well bore (lost circulation); put gas or saltwater zones behind pipe before drilling into the production zone; or provide additional wellbore structure.

Intermediate casing is set prior to drilling through the hydrocarbon bearing zone, and may be cemented behind the entire casing string from the top of the well to the bottom of the casing shoe, depending on intermediate casing depth. Intermediate casing provides an additional protective barrier across to prevent contamination of protected groundwater zones.

The 2011 RDSGEIS and the proposed revisions to the NYCRR include important improvements for intermediate casing. Overall, NYSDEC's intermediate casing requirements for HVHF wells are robust. NYSDEC proposed a number of substantial improvements in the intermediate casing requirements. The most notable improvement to the RDSGEIS mitigation and the NYCRR is that intermediate casing will be required in wells that undergo HVHF treatments to provide an additional protective layer of casing and cementing in the well. The RDSGEIS and the NYCRR requires intermediate casing be fully cemented, and the cement placement and bond be verified by well logging tools.

However, the remaining area for improvement in the NYCRR is to establish intermediate casing and cementing standards for all wells that will not undergo HVHF treatment, but will require the installation of intermediate casing. The proposed NYCRR is silent on the intermediate casing and cementing standards for wells that will not undergo HVHF treatment. NYS should provide instruction on intermediate casing standards for all wells that require it.

There are a number of new intermediate casing requirements proposed for HVHF wells that are standard industry best practices for all oil and gas wells. Those requirements should be included in the NYCRR Part 554 (drilling practices for all oil and gas wells), and not just covered in the new NYCRR Part 560 (drilling practices for HVHF wells).

Recommendation No. 15: The NYCRR should be revised to establish intermediate casing and cementing standards for all wells at NYCRR Part 554 (drilling practices for all oil and gas wells).

This section reviews the proposed changes to intermediate casing requirements and supports the improvements that have been made. It also makes suggestions for improved regulatory clarity and offers recommendations for regulatory program revisions.

An analysis of the proposed RDSGEIS conditions found in Appendices 8, 9, and 10 is provided below, and compared to the proposed NYCRR. Recommendations are made to improve consistency in the documents and highlight additional best practices that should be considered.

The 2011 RDSGEIS: The 2011 RDSGEIS recommends that intermediate casing be required in wells that undergo HVHF treatments, to provide an additional protective layer of casing and cementing in the well. The 2011 RDSGEIS recommends that intermediate casing be fully cemented, and the cement placement and bond be verified by well logging tools. This is an excellent recommendation. The 2011 RDSGEIS states:

> *Current casing and cementing practices attached as conditions to all oil and gas well drilling permits state that intermediate casing string(s) and cementing requirements will be reviewed and approved by the Department on an individual well basis.* ***<u>The Department proposes to require, via permit condition and/or regulation, that for high-volume hydraulic fracturing the installation of intermediate casing in all wells covered under the SGEIS would be required</u>.*** *However, the Department may grant an exception to the intermediate casing requirement when technically justified [emphasis added].*[40]
>
> *The current dSGEIS proposes to require in most cases fully cemented intermediate casing, with the setting depths of both surface and intermediate casing determined by site-specific conditions*[41]
>
> *Requirement for fully cemented production casing or intermediate casing (if used), with the cement bond evaluated by use of a cement bond logging tool; and*[42]
>
> *Fully cemented intermediate casing would be required unless supporting site-specific documentation to waive the requirement is presented. This directly addresses gas migration concerns by providing additional barriers (i.e., steel casing, cement) between aquifers and shallow gas-bearing zones.*[43]
>
> *Depending on the depth of the well and local geologic conditions, there may be one or more intermediate casing string.* [44]
>
> *Use of centralizers to ensure that the cement sheath surrounds the casing strings, including the first joint of surface and intermediate casings.* [45]

The 2011 RDSGEIS proposes a waiver process to exclude intermediate casing under some circumstances:

> *A request to waive the intermediate casing requirement would need to be made in writing with supporting documentation showing that environmental protection and public safety would not be compromised by omission of the intermediate string. An example of circumstances that may warrant consideration of the omission of the intermediate string and granting of the waiver could include: 1) deep set surface casing, 2) relatively shallow total depth of well and 3) absence of fluid and gas in the section between the surface casing and target interval. Such intermediate casing waiver request may also be supported by the inclusion of information on the subsurface and geologic conditions from offsetting wells, if available.* [46]

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[40] 2011 NYSDEC, RDSGEIS, Page 7-52.

[41] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 25.

[42] 2011 NYSDEC, RDSGEIS, Page 1-12.

[43] 2011 NYSDEC, RDSGEIS, Page 1-12.

[44] 2011 NYSDEC, RDSGEIS, Page 5-92.

[45] 2011 NYSDEC, RDSGEIS, Page 7-42.

[46] 2011 NYSDEC, RDSGEIS, Page 7-52.

The proposed waiver process conflicts with the stated intent of requiring intermediate casing for HVHF wells. The RDSGEIS states that the reason intermediate casing is required for a HVHF well is because it:

> *…directly addresses gas migration concerns by providing additional barriers (i.e., steel casing, cement) between aquifers and shallow gas-bearing zones.*[47]

As proposed, NYSDEC would consider a wavier if the surface casing is set "deep" or if the well is "shallow"; however, these depths are not defined. The RDSGEIS does not explain how the use of deep-set surface casing or shallow surface casing provides the same protection to aquifers as installing a second string of intermediate casing and cement.

Additionally, as proposed, NYSDEC would consider a wavier if there is an "*absence of fluid and gas in the section between the surface casing and target interval.*[48]" This requirement is incongruous, because there will always be some type of fluid in the formation between the surface casing and target interval; therefore, the conditions for this waiver to occur would never be realized.

Recommendation No. 16: The SGEIS and NYCRR should be revised to remove the waiver provisions for intermediate casing on HVHF wells, or the SGEIS and NYCRR should be revised to include technical justifications, rationale and thresholds for proposed waivers.

The 2011 RDSGEIS requires that intermediate casing be cemented and evaluated for quality as follows:

> *Intermediate casing would be cemented to the surface and cementing would be by the pump and plug method with a minimum of 25% excess cement unless caliper logs are run, in which case 10% excess would suffice.*[49]
>
> *The operator would run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the intermediate casing and the production casing. The quality and effectiveness of the cement job would be evaluated using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of API Guidance Document HF1 (First Edition, October 2009). Remedial cementing would be required if the cement bond is not adequate to drill ahead and isolate hydraulic fracturing operations, respectively.*[50]

The requirements for intermediate casing are listed in Appendices 8, 9, and 10 of the RDSGEIS.

The 2011 RDSGEIS Appendix 8: Appendix 8 Casing and Cementing Practices requires intermediate casing be set only in certain circumstances.

> *Intermediate casing string(s) and the cementing requirements for that casing string(s) will be reviewed and approved by Regional Mineral Resources office staff on an individual well basis.*[51]

[47] 2011 NYSDEC, RDSGEIS, Page 1-12.

[48] 2011 NYSDEC, RDSGEIS, Page 7-52.
[49] 2011 NYSDEC, RDSGEIS, Page 7-53.
[50] 2011 NYSDEC, RDSGEIS, Page 7-54.
[51] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 2.

The 2011 RDSGEIS Appendix 9: Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers requires intermediate casing be set:

> *If multiple fresh water zones are known to exist or are found or if shallow gas is present, this office may require multiple strings of surface casing to prevent gas intrusion and/or preserve the hydraulic characteristics and water quality of each fresh water zone. The permittee must immediately inform this office of the occurrence of any fresh water or shallow gas zones not noted on the permittee's drilling application and prognosis. This office may require changes to the casing and cementing plan in response to unexpected occurrences of fresh water or shallow gas, and may also require the immediate, temporary cessation of operations while such alterations are developed by the permittee and evaluated by the Department for approval.*[52]

The main problem with the conditions of Appendices 8 and 9 is that there is no specific guidance for intermediate casing and cementing, if the intermediate casing string is required as part of the well construction design.

> **Recommendation No. 17**: The SGEIS (Appendices 8 and 9) and NYCRR should be revised to provide specific intermediate casing and cementing requirements, as explained further in Appendix B.

The 2011 RDSGEIS Appendix 10: Appendix 10 contains Proposed Supplementary Permit Conditions for HVHF operations, including additional intermediate casing requirements.

The 2011 RDSGEIS Appendix 10 requires intermediate casing be set, unless a waiver is granted:

> *Intermediate casing must be installed in the well. The setting depth and design of the casing must consider all applicable drilling, geologic and well control factors. Additionally, the setting depth must consider the cementing requirements for the intermediate casing and the production casing as noted below. Any request to waive the intermediate casing requirement must be made in writing with supporting documentation and is subject to the Department's approval. Information gathered from operations conducted on any single well or the first well drilled on a multi-well pad may serve to form the basis for the Department waiving the intermediate casing requirement on subsequent wells in the vicinity of the single well or subsequent wells on the same multi-well pad.*[53]

The 2011 RDSGEIS Appendix 10 requires intermediate casing be completely cemented and the department be notified of cementing operations:

> *This office must be notified ______ hours prior to intermediate casing cementing operations. Intermediate casing must be fully cemented to surface with excess cement. Cementing must be by the pump and plug method with a minimum of 25% excess cement unless caliper logs are run, in which case 10% excess will suffice. (Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*[54]

The 2011 RDSGEIS Appendix 10 requires a cement bond evaluation log:

[52] 2011 NYSDEC, RDSGEIS, Appendix 9, Page 2.
[53] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.
[54] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

> *The operator must run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the intermediate casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009). Remedial cementing is required if the cement bond is not adequate for drilling ahead (i.e., diversion or shut-in for well control).*[55]

The 2011 RDSGEIS Appendix 10 requires new casing and the use of American Petroleum Institute (API) standards for: casing thread compounds, centralizer placement, and cement composition (including the requirement to use gas-blocking additives).

> *With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *a) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;*
>
> *b) casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);*
>
> *c) at least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);*
>
> *d) cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive…*[56]

Appendix 10 requires: drilling mud be circulated and conditioned prior to cementing; the use of a spacer fluid to separate drilling mud from cement, avoiding drilling mud contamination; and cement installation methods that inhibit voids in the cement.

> *e) Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;*
>
> *f) A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement; and*
>
> *g) The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus...*[57]

[55] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

[56] 2011 NYSDEC, RDSGEIS, Appendix 10, Pages 5-6.

[57] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

Appendix 10 establishes a specific period of time required for the cement to harden and a compressive strength standard that the cement must achieve before drilling continues deeper in the hole. This avoids disturbing the cement until it has completely set.

> *h) After the cement is pumped, the operator must wait on cement (WOC):*
>
> > *1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and*
> >
> > *2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig.*[58]

Appendix 10 requires records be kept as follows:

> *i) A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.* [59]

An analysis of the Appendices 8, 9, and 10 permit conditions requirements is provided in table format in Appendix B. Recommendations are listed in the table for improving the requirements and addressing inconsistencies.

NYCRR Proposed Revisions: The existing regulations at 6 NYCRR § 554 do not include specific requirements for intermediate casing, when intermediate casing is part of the well construction design.

A new section of regulations at 6 NYCRR § 560.6(c)(13, 14 and 15) proposes to add intermediate casing requirements for HVHF wells:

> *(13) Intermediate casing must be installed in the well. The setting depth and design of the casing must be determined by taking into account all applicable drilling, geologic and well control factors. Additionally, the setting depth must consider the cementing requirements for the intermediate casing and the production casing as noted below. Any request to waive the intermediate casing requirement must be made in writing with supporting documentation and is subject to the department's approval. Information gathered from operations conducted on any single well or the first well drilled on a multi-well pad may be considered by the department upon a request for a waiver of the intermediate casing requirement on subsequent wells in the vicinity of the single well or subsequent wells on the same multi-well pad.*

[58] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[59] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

(14) As specified on a permit to drill, deepen, plug back and convert, the department must be notified prior to intermediate casing cementing operations. Intermediate casing must be fully cemented to surface with excess cement. Cementing must be by the pump and plug method with a minimum of 25 percent excess cement unless caliper logs are run, in which case 10 percent excess will suffice.

(15) The operator must run a radial cement bond evaluation log or other evaluation approved by the department to verify the cement bond on the intermediate casing. Remedial cementing is required if the cement bond is not adequate for drilling ahead (i.e., diversion or shut-in for well control).

Additional intermediate casing and cementing standards are included at 6 NYCRR § 560.6(c)(10) for HVHF wells:

(10) With respect to all surface, intermediate and production casing run in the well, and in addition to the department's casing and cementing requirements and any approved centralizer plan for intermediate casing, the following shall apply:

(i) all casings must be new and conform to industry standards specified in the permit to drill;

(ii) welded connections are prohibited;

(iii) casing thread compound and its use must conform to industry standards specified in the permit to drill;

(iv) in addition to centralizers otherwise required by the department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed (except production casing) and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill;

(v) cement must conform to industry standards specified in the permit to drill and the cement slurry must be prepared to minimize its free water content in accordance with the industry standards and specifications, and contain a gas-block additive;

(vi) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;

(vii) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;

(viii) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;

(ix) after the cement is pumped, the operator must wait on cement (WOC) until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blowout preventer. The operator may request a waiver from the department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 pounds per square inch gage; and

(x) a copy of the cement job log for any cemented casing string in the well must be available to the department at the well site during drilling operations, and thereafter available to the department upon request. The operator must provide such log to the department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a department permit issued

> *pursuant to Part 550 of this Title. If the well is located on a multi-well pad, all cementing job logs must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title.*

An analysis of the proposed Appendices 8, 9, and 10 permit conditions requirements and the proposed changes to NYCRR is provided in table format in Appendix B. Recommendations for improving requirements are listed in the table.

Recommendation No. 18: The recommendations listed in the Intermediate Casing Analysis Table (Appendix B to this report) should be considered for the SGEIS and the NYCRR, including:

Waiver Provisions: It is best practice to install intermediate casing on a case-by-case basis for most wells; however, it is best practice to install it on all HVHF wells. The waiver provision proposed in the RDSGEIS to exclude intermediate casing on HVHF wells is not technically justified.

Setting Depth: Best practice is to set intermediate casing at least 100' below the deepest protected groundwater, to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. Although intermediate casing setting depth is site specific, there should be criteria for determining that depth. This requirement should apply to all NYS wells.

Protected Water Depth Verification: The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method during drilling, ensuring intermediate casing protects that groundwater. This requirement should apply to all NYS wells where intermediate casing is set.

Cement Sheath Width: A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells where intermediate casing is set.

Amount of Cement in Annulus: It is best practice to fully cement intermediate casing if technically feasible to isolate protected water zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. If the casing cannot be fully cemented, most states require cement to be placed from the casing shoe to a point at least 500-600' above the shoe. This requirement should apply to all wells where intermediate casing is set.

Excess Cement: 25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where intermediate casing is set.

Cement Type: Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). The cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where intermediate casing is installed, not just HVHF wells.

Cement Mix Water Temperature and pH Monitoring: Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where intermediate casing is required, not just HVHF wells.

Lost Circulation Control: Lost circulation control is best practice. This requirement should apply to all NYS wells where intermediate casing is required.

Spacer Fluids: The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where intermediate casing is used, not just HVHF wells.

Hole Conditioning: Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Cement Installation and Pump Rate: The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Rotation and Reciprocation: Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.

Centralizers: The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where intermediate casing is installed.

Casing Quality: The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where intermediate casing is set.

Casing Thread Compound: The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Drilling Mud: The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells during the period when drilling occurs through protected water zones.

Cement Setting Time: Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells, not just HVHF wells.

NYSDEC Inspector: Best practice is to have a state inspector onsite during cementing operations. This requirement should apply to all NYS wells where intermediate casing is installed.

Cement QA/QC: The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where intermediate casing is set.

Record Keeping: Best practice is to keep permanent records for each well, even after the well is plugged and abandoned (P&A'd). This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Additional Casing or Repair: NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.

Pressure Testing: Casing and piping should be pressure tested.[60]

[60] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, Page 109.

8. Production Casing

Background: In 2009, HCLLC recommended NYCRR be revised to include additional production casing construction standards. Please refer to HCLLC's September 16, 2009 Report, *New York State (NYS) Casing Regulation Recommendations* for more specific recommendations on production casing the technical basis for HCLCC's recommendations.

Production casing is the last string of casing set in the well. It is called "production casing" because it is set across the hydrocarbon-producing zone, or alternatively sets just above the hydrocarbon zone. Production casing can be run all the way from the surface of the well across the hydrocarbon zone (production casing string) or can be hung from the surface or intermediate casing at a point deeper in the well (production liner).

If production casing is set across the hydrocarbon-producing zone, it is called a "cased hole" completion. In this scenario, production casing is lowered into the hole and cemented in place. Explosives are then lowered inside the production casing (perforation guns) to perforate holes through the pipe/cement barrier to allow oil and/or gas to enter the wellbore. In some cases, a drilling engineer may elect not to set production casing. This is called an "open hole" completion.

NYSDEC recommends a full string of production casing be set across the production zone and be run to surface, and that the production casing be cemented in place. This is a best practice for HVHF wells.

Production casing is used to isolate hydrocarbon zones and contain formation pressure. Production casing pipe and cement integrity is very important, because it is the piping/cement barrier that is exposed to fracture pressure, acid stimulation treatments, and other workover/stimulation methods used to increase hydrocarbon production.

The 2011 RDSGEIS and proposed revisions to the NYCRR include substantial improvements for production casing. NYSDEC's proposed production casing requirements for HVHF wells are robust. The most notable improvement to the NYCRR is that production casing must be set from the well surface through the production zone. This provides an additional protective layer of casing and cementing in the well during HVHF treatments. The RDSGEIS and NYCRR requires production casing be fully cemented, if intermediate casing is not set. If intermediate casing is set, it requires production casing be tied into the intermediate casing. NYCRR also requires the cement placement and bond be verified by well logging tools. These requirements are best practice.

NYSDEC's proposed HVHF production casing design prevents pollution of protected groundwater by constraining the HVHF pressurized fluid treatment to the inside of the production casing string as it passes the protected groundwater zone. Additionally, behind the production casing string there are two additional layers of casing and cement installed as a barrier across protected waters (e.g. surface and intermediate casing).

This section reviews the proposed changes to production casing requirements and supports the improvements that have been made. It also makes suggestions for improved regulatory clarity and offers recommendations for regulatory program revisions.

An analysis of the proposed RDSGEIS conditions found in Appendices 8, 9, and 10 is provided below, and compared to the proposed NYCRR. Recommendations are made to improve consistency in the documents and highlight additional best practices that should be considered.

The 2011 RDSGEIS: The 2011 RDSGEIS requires that production casing be installed and fully cemented across the production zone in wells that undergo HVHF treatments. The 2011 RDSGEIS states:

> *Requirement for fully cemented production casing or intermediate casing (if used), with the cement bond evaluated by use of a cement bond logging tool.* [61]
>
> *Anticipated Marcellus Shale fracturing pressures range from 5,000 pounds per square inch (psi) to 10,000 psi, so production casing with a greater internal yield pressure than the anticipated fracturing pressure must be installed.* [62]

The 2011 RDSGEIS Appendix 8: Appendix 8 NYSDEC's Casing and Cementing Practices includes the following production casing requirements for all wells.

12. *The production casing cement shall extend at least 500 feet above the casing shoe or tie into the previous casing string, whichever is less. If any oil or gas shows are encountered or known to be present in the area, as determined by the Department at the time of permit application, or subsequently encountered during drilling, the production casing cement shall extend at least 100 feet above any such shows. The Department may allow the use of a weighted fluid in the annulus to prevent gas migration in specific instances when the weight of the cement column could be a problem.*
13. *Centralizers shall be placed at the base and at the top of the production interval if casing is run and extends through that interval, with one additional centralizer every 300 feet of the cemented interval. A minimum of 25% excess cement shall be used. When caliper logs are run, a 10% excess will suffice. Additional excesses may be required by the Department in certain areas.*
14. *The pump and plug method shall be used for all production casing cement jobs deeper than 1500 feet. If the pump and plug technique is not used (less than 1500 feet), the operator shall not displace the cement closer than 35 feet above the bottom of the casing. If plugs are used, the plug catcher shall be placed at the top of the lowest (deepest) full joint of casing.*
15. *The casing shall be of sufficient strength to contain any expected formation or stimulation pressures.*
16. *Following cementing and removal of cementing equipment, the operator shall wait until a compressive strength of 500 psi is achieved before the casing is disturbed in any way. The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing tickets and/or the drilling log. WOC time shall be adjusted based on the results of the test.*[63]

The 2011 RDSGEIS Appendix 9: Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers does not include any additional requirements for production casing.

[61] 2011 NYSDEC, RDSGEIS, Page 1-12.

[62] 2011 NYSDEC, RDSGEIS, Page 5-92.

[63] 2011 NYSDEC, RDSGEIS, Appendix 8, Page 2-3.

The 2011 RDSGEIS Appendix 10: Appendix 10 contains Proposed Supplementary Permit Conditions for HVHF operations, including additional production casing requirements.

The 2011 RDSGEIS Appendix 10 requires production casing run the entire length of the wellbore, which is an excellent recommendation. Appendix 10 also requires production casing be tied into intermediate casing with at least 500' of cement:

> *36) Production casing must be run to the surface. This office must be notified _______ hours prior to production casing cementing operations. If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).*[64]

Appendix 10 requires a cement bond evaluation log, which is another excellent recommendation:

> *The operator must run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the production casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009). Remedial cementing is required if the cement bond is not adequate to effectively isolate hydraulic fracturing operations.*[65]

However, Appendix 10 includes a waiver provision that would exempt an operator from installing production casing cement as described above. This waiver provision is based solely on whether oil and gas might migrate from one pool or stratum to another. It does not address any of the other reasons why production casing cementing is important and required by NYSDEC in HVHF wells.

> *Any request to waive any of the preceding cementing requirements must be made in writing with supporting documentation and is subject to the Department's approval.*
>
> *The Department will only consider a request for a waiver if the open-hole wireline logs including a narrative analysis of such and all other information collected during drilling from the same well pad or offsetting wells verify that migration of oil, gas or other fluids from one pool or stratum to another will be prevented. (Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*[66]

Recommendation No. 19: The production casing cementing waiver should be removed for HVHF wells, or NYSDEC should provide more technical justification and rationale for the waiver. NYSDEC should show how environmental protection and safety objectives can be achieved to the same level with the waiver as without it.

The 2011 RDSGEIS Appendix 10 requires new casing and the use of American Petroleum Institute (API) standards for: casing thread compounds, centralizer placement, and cement composition (including the requirement to use gas-blocking additives).

[64] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.
[65] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.
[66] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

31) With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:

e) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;

f) Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);

g) At least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);

h) Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive…[67]

Appendix 10 requires: drilling mud be circulated and conditioned prior to cementing; the use of spacer fluid to separate drilling mud from cement, avoiding drilling mud contamination; and cement installation methods that inhibit voids in the cement.

e) Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;

f) A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;

h) The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus…[68]

Appendix 10 establishes a specific period of time required for the cement to harden and a compressive strength standard that the cement must achieve before drilling continues deeper in the hole. This avoids disturbing the cement until it has completely set.

h) After the cement is pumped, the operator must wait on cement (WOC):

1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and

2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig.[69]

[67] 2011 NYSDEC, RDSGEIS, Appendix 10, Pages 5-6.

[68] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[69] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

Appendix 10 requires records be kept as follows:

> *A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.*[70]

An analysis of the Appendices 8, 9, and 10 permit conditions requirements is provided in table format in Appendix C. Recommendations are listed in the table for improving the requirements and addressing inconsistencies.

NYCRR Proposed Revisions: The existing regulations at 6 NYCRR § 554 include requirements for production casing:

> *If it is elected to complete a rotary-drilled well and production casing is run, it shall be cemented by a pump and plug or displacement method with sufficient cement to circulate above the top of the completion zone to a height sufficient to prevent any movement of oil or gas or other fluids around the exterior of the production casing. In such instance, operations shall be suspended until the cement has been permitted to set in accordance with prudent current industry practices.*[71]

A new section of regulations at 6 NYCRR § 560.6(c)(16) proposes to add production casing requirements for HVHF wells.

> *(16) Production casing must be run to the surface. If installation of the intermediate casing is waived by the department, then production casing must be fully cemented to surface. __**If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 300 feet of cement measured using True Vertical Depth**__. Any request to waive any of the cementing requirements of this paragraph must be made in writing with supporting documentation and must be approved by the department. The department will only consider a request for a waiver if the open-hole wireline logs including a narrative analysis of such and all other information collected during drilling from the same well pad or offsetting wells verify that migration of oil, gas or other fluids from one pool or stratum to another will otherwise be prevented [emphasis added].*

The proposed regulations at 6 NYCRR § 560.6(c)(16) are inconsistent with the Appendix 10 requirement to cement the production casing with a 500' overlap into the intermediate casing.

> *If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).*[72]

[70] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 6.

[71] 6 NYCRR V.B. §554.4(d)

[72] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 7.

Recommendation No. 20: A production casing 500' cement overlap into the intermediate casing is more protective; 6 NYCRR § 560.6(c)(16) should be revised to match Appendix 10.

A new section of regulations at 6 NYCRR § 560.6(c)(17) requires production casing cement be verified for HVHF wells:

> *(17) The operator must run a radial cement bond evaluation log or other evaluation approved by the department to verify the cement bond on the production casing. Remedial cementing is required if the cement bond is not adequate to effectively isolate hydraulic fracturing operations.*

Additional production casing and cementing standards are included at 6 NYCRR § 560.6(c)(10) for HVHF wells.

> *(10) With respect to all surface, intermediate and production casing run in the well, and in addition to the department's casing and cementing requirements and any approved centralizer plan for intermediate casing, the following shall apply:*
>
> *(i) all casings must be new and conform to industry standards specified in the permit to drill;*
>
> *(ii) welded connections are prohibited;*
>
> *(iii) casing thread compound and its use must conform to industry standards specified in the permit to drill;*
>
> *(v) cement must conform to industry standards specified in the permit to drill and the cement slurry must be prepared to minimize its free water content in accordance with the industry standards and specifications, and contain a gas-block additive;*
>
> *(vi) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;*
>
> *(vii) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;*
>
> *(viii) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;*
>
> *(ix) after the cement is pumped, the operator must wait on cement (WOC) until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blowout preventer. The operator may request a waiver from the department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 pounds per square inch gage; and*
>
> *(x) a copy of the cement job log for any cemented casing string in the well must be available to the department at the well site during drilling operations, and thereafter available to the department upon request. The operator must provide such log to the department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title. If the well is located on a multi-well pad, all cementing job logs must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a department permit issued pursuant to Part 550 of this Title.*

An analysis of the proposed Appendices 8, 9, and 10 permit conditions requirements and the proposed changes to the NYCRR is provided in table format in Appendix C. Recommendations for improving requirements are listed in the table.

Recommendation No. 21: The recommendations listed in the Production Casing Analysis Table (Appendix C to this report) should be considered for the SGEIS and the NYCRR, including:

Casing Design: For all wells, it is best practice for the productive horizon(s) to be determined by coring, electric log, mud-logging, and/or testing to aide in optimizing final production string design and placement. It is best practice to install production casing on a case-by-case basis for most wells; however, it is best practice to install a full string of production casing on HVHF wells to provide a conduit for the HVHF job and provide an extra layer of casing and cement.

Cement Sheath Width: A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells.

Amount of Cement in Annulus: Cementing production casing to surface if technically feasible (becomes more difficult with increasing depth), or at least 500' into the intermediate casing string is best practice. This requirement should apply to all NYS wells where production casing is set.

Excess Cement Requirements: 25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where production casing is set.

Cement Type: Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where production casing is installed, not just HVHF wells.

Cement Mix Water Temperature and pH Monitoring: Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where production casing is required, not just HVHF wells.

Lost Circulation Control: Lost circulation control is best practice. This requirement should apply to all NYS wells where production casing is required.

Spacer Fluids: The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where production casing is used, not just HVHF wells.

Hole Conditioning: Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Cement Installation and Pump Rate: The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Rotation and Reciprocation: Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This will become more difficult with a deviated wellbore, but should be attempted if achievable. This requirement should apply to all NYS oil and gas wells, not just HVHF wells.

Centralizers: Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where production casing is installed.

Casing Quality: The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where production casing is set.

Casing Thread Compound: The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.

Cement Setting Time: Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. This requirement should apply to all NYS wells, not just HVHF wells.

NYSDEC Inspector: Best practice is to have a state inspector onsite during cementing operations. This is more typical for surface and intermediate casing, but can be considered for production casing as well.

Cement QA/QC: The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where production casing is set.

Record Keeping: Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Additional Casing or Repair: NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.

Pressure Testing: Casing and piping should be pressure tested.[73]

[73] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, p. 109.

9. Permanent Wellbore Plugging & Abandonment Requirements

Background: In 2009, HCLLC recommended that NYSDEC establish specific criteria to determine when a well must be permanently plugged and abandoned (P&A'd) and recommended improvements in NYS' well plugging regulations, incorporating best technology and practices.

Several terms are used to describe the condition of oil and gas wells that are not active hydrocarbon producers.

- Temporary Abandonment. This term is used to describe a well that may be temporarily suspended as a production well. The well may be shut-in awaiting repairs, a stimulation treatment, workover (e.g. drilling into a new zone) or a decision to finally P&A the well. A reasonable amount time should be afforded to the operator to complete the well work, or to decide when to P&A the well; however, a well should not be temporarily abandoned for a long period of time, because it poses a risk to the environment, especially if the well is known to have a leak or mechanical malfunction. Leaking or malfunctioning wells should be repaired in a timely manner or the well should be permanently P&A'd.

  In 2003, ICF Consulting produced a report for the New York State Energy Research and Development Authority (NYSERDA) that concluded NYS had 5,900 shut-in or temporarily abandoned wells, 39% of the 15,000 known wells.[74] ICF concluded that more than half the 5,900 wells have been "temporarily" abandoned for more than nine years. ICF concluded that:

  > *NYS is one of the few oil and gas producing states that have no specific regulatory provisions for long-term shut-in wells (more than two years). New York's current regulations allow an initial shut in period of one-year and an extension of up to one year, renewable for additional successive periods…*[75]

  ICF concluded that while operators are required to contact NYS to justify temporary abandonment extensions beyond one year, NYS' lack of resources to oversee the program has resulted in many wells remaining idle and not properly P&A'd for years:

  > *The practical effect is that New York's idle well regulation cannot be adequately enforced due to constraints on manpower and other agency resources, and as a result, New York has a defacto long-term inactive well program. For example New York has approximately 1,379 gas wells and 1440 oil wells with either inactive or unknown status that have no reported production since 1992.* [76]

- Permanent Abandonment. A well that is no longer needed to produce hydrocarbons should be plugged (e.g. cement barriers installed, failed casing removed, mechanical plugs set), surface equipment removed (e.g. wellhead and piping), and permanently abandoned. Operators typically do not monitor well condition once a P&A'd job is complete and approved by an agency.

[74] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 1. A final version of this report could not be located on the world-wide web.

[75] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 5.

[76] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 36.

- Improperly Abandoned Well. This term describes a well that was P&A'd, but was done so in a manner where the well still poses a risk to the environment (e.g. insufficient barriers or cement used to seal the well). Because operators typically do not monitor the condition of P&A'd wells, improperly abandoned wells often go un-resolved.

  The problem of improperly abandoned wells in NYS may be a significant issue, because NYS' P&A regulations currently only require 15' cement plugs, which NYSDEC now recognizes as deficient. Therefore, most wells in the state were not P&A'd using a quality standard that would be considered best technology and best practice today.

- Orphaned Well. This term describes a well that was orphaned by the well operator (e.g. insolvent, absentee, or non-responsive well owners) and the well was not P&A'd. Because, by definition, an "orphaned well" does not have an operator to monitor its condition, permanent abandonment of these wells typically becomes a government or property owner responsibility. Given limited agency resources, the magnitude of the environmental hazard posed by any particular orphaned well often is unknown. Unless government or property owners make it a priority to fund well monitoring or plug the well, the potential environmental impacts of orphaned wells cannot be ascertained.

In 2003, ICF Consulting, further examined 4,140 of the long-term inactive wells in NYS and concluded that:

- 546 of the 4,140 wells (13%) were drilled and completed before 1924 (over 87 years old now);
- 1,568 of the 4,140 wells (38%) were drilled and completed from 1924-1964 (at least 47 years old now, and possibly up to 87 years old); and
- 2,026 of the 4,140 wells (49%) had no information on the date of complete or condition.[77]

Therefore, there are 2,114 wells that are at least 47 years old and some more than 87 years old that still have not been properly abandoned in NYS, and 2,026 wells where the age and condition is unknown (and must be assumed improperly abandoned).

NYS' 2009 Annual Oil and Gas Report[78] shows improperly abandoned and orphaned wells continue to be a significant problem in NYS. NYSDEC reports:

> ***Abandoned, unreported and inactive wells continued to be a problem. In 2009 a total of 450 operators reported 3,043 wells with zero production. This is in addition to over 4,100 orphaned and inactive wells in the Department's records****. Enforcement actions have reduced the number of unreported wells yet some operators refused to file their annual reports. The operators that remained out of compliance have been referred to the Office of General Counsel for additional enforcement actions.[emphasis added]*
>
> *DEC has at least partial records on 40,000 wells, but estimates that over 75,000 oil and gas wells have been drilled in the State since the 1820s.* ***Most of the wells date from before New York established a regulatory program****.* ***Many of these old wells were never properly plugged or were plugged using older techniques that were less reliable and long-lasting than modern methods.*** *[emphasis added]*

[77] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 32.

[78] New York State Oil, Gas and Mineral Resources, 26th Annual Report for Year 2009 and Appendices, Prepared by NYSDEC, 2009, pp. 22-23.

> *Every year while conducting scheduled inspections or investigating complaints, DEC staff discover more abandoned wells. Extensive courthouse research is often required to identify a well's previous owners. Many of these cases take several years to resolve as DEC pursues legal action against the responsible parties.*
>
> *New York has an Oil and Gas Account which was created to plug problem abandoned wells. It is funded by a $100 per well permit fee; at the end of 2009 the balance was $208,806. DEC has over 500 wells on its priority plugging list. Since* ***the funds are insufficient to plug all the priority wells****, DEC continues to pursue other mechanisms to plug abandoned wells [emphasis added].*

Well construction standards, techniques and technology have improved over time, and it is reasonable to assume that most of these long-term idle wells were not constructed to today's standards, have been subject to mechanical wear and corrosion, and warrant proper abandonment to mitigate risk to protected groundwater resources.

To compound problems, many wells that have not been properly abandoned do not have financial security (e.g. bonds) in place to fund P&A work. ICF reported that, in 2003, NYS had more than 3,500 wells that needed to be P&A'd, but there was no financial security in place (e.g. wells that were grandfathered from NYS bonding requirements). Additionally, ICF reported that 675 of the existing oil and gas wells in NYS have operators that do not comply with the current bonding requirements, and numerous operators that might comply with the existing bonding requirements have plugging liability in amounts that exceed NYS' current bonding requirements, which are too low and do not keep pace with the actual costs of P&A'ing wells today.[79]

The number of temporarily abandoned wells, improperly abandoned wells, and orphaned wells in NYS is a significant issue as shale gas resources are developed, because these old wells could provide a vertical conduit for pollutants to reach protected aquifers. Shale gas wells drilled and fracture stimulated nearby a temporarily abandoned, improperly abandoned, or orphaned well pose a risk. For example, a HVHF treatment can propagate a fracture that, depending on geology, HVHF design, and well depths, could pose a risk of intersection with a nearby well (active producer, abandoned or orphaned well).

Temporarily abandoned wells, improperly abandoned wells, and orphaned wells all pose a risk to the environment. Wellbore infrastructure can corrode and erode, failing over time and creating a potential pollutant pathway for hydrocarbons to move vertically through failed casing or cement to groundwater resources. These wells can either leak gas on their own or provide a vertical pollutant pathway to groundwater resources that can be activated by new well activity nearby.

In 2009, HCLLC recommended that temporary abandonment be limited to no longer than a one-year period, with a wellbore integrity monitoring requirement to ensure that the well is not leaking during temporary abandonment, and a requirement to permanently abandon the well after it is idle for more than a year. HCLLC recommended that NYSDEC carefully examine idle wells that have not been properly P&A'd and that are in close proximity to drinking water sources and in areas under consideration for new HVHF treatments, and require those wells to be P&A'd as a high priority and before shale gas drilling operations commence in those areas.

[79] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report, Prepared for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page 35-36.

A report documenting specific cases of well pollution caused by NYS' improperly abandoned wells or orphaned wells could not be located; however, neighboring Pennsylvania has completed an analysis of this problem, and it sheds light on the problems NYS may encounter.

Pollution caused by improperly abandoned wells in Pennsylvania is documented in a 2009 report prepared by Pennsylvania Department of Environmental Protection (PADEP). The PADEP report lists 27 cases where improperly abandoned wells have been the source of groundwater contamination.[80] In some of the 27 cases the wells were abandoned according to the standard practices of the time, but now leak and need to be re-abandoned using improved materials and techniques. Some of the cases cited by PADEP include very old well construction techniques, for example, surface casing made out of wood that has rotted away, and wells with no surface casing or cement installed at all. These wells have provided a conduit for gas and other pollutants to reach groundwater through damaged or worn casing, poorly installed cement, or more directly where casing or cement was not initially installed.

PADEP also identified wells that need to be P&A'd, but have not yet been addressed due to the lack of a responsible party and/or on account of PADEP resource limitations.[81]

There were three cases cited by PADEP where fracture stimulations in an operating well communicated with a nearby abandoned well, causing a gas leak in the abandoned well.[82] PADEP's study highlighted the importance of locating orphaned and improperly abandoned wells near new oil and gas developments, and study shows the importance of properly abandoning wells before new development proceeds.

A 2011 Duke University study covering Pennsylvania and New York found methane contamination of drinking water associated with shale-gas extraction. The study found that methane concentrations were 17 times higher, on average, in drinking water wells in active drilling and extraction areas than in wells in nonactive areas.[83] Clearly, the higher incidence rate of methane contamination in drinking water wells in shale gas extraction areas is not a coincidence, but is an indicator of shale gas drilling and completion operations mobilizing gas from the shale gas reservoir into protected aquifers. One of the most likely pathways for leaking of gas mobilized by HVHF is a nearby existing well that either was improperly constructed or improperly plugged. Given their failed cement, corroded casing, or lack of casing or cement, such improperly abandoned wells present vertical pathways to aquifers and drinking water resources.

Mechanical failure, human error, and engineering design flaws do occur in the construction and operation of wells. Indeed, groundwater contamination has been attributed to operational failures at various Marcellus Shale gas development operations in Pennsylvania, including operations by Cabot Oil & Gas Corporation, Catalyst Energy, Inc., and Chesapeake Energy Corporation.

[80] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009.

[81] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009. Cases include: Independent Valley News Migration, Allegheny County – SWRO – March 2009; Versailles Migration, Versailles, Allegheny County – SWRO – 2007 through 2008; Childers Migration, Washington County – SWRO – June 2005; Groshek Migration, Keating Twp., McKean County – NWRO – 2008; and Skinner Migration, Columbus Twp., Warren County – NWRO.

[82] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009.

[83] Osborn, S.G., A. Vengosh, N.R. Warner, R.B. Jackson, 2011 Methane Contamination of Drinking Water Accompanying Gas Well Drilling and Hydraulic Fracturing, Proceedings of the National Academy of Sciences, U.S.A.; DOI: 10.1073/pnas.1100682108, p.2.

For example, on February 27, 2009, the Pennsylvania Department of Environmental Protection (PADEP) issued a Notice of Violation to Cabot Oil & Gas Corporation for unpermitted discharge of polluting substances and failure to prevent gas from entering fresh groundwater, among other deficiencies, in connection with its drilling activities in Dimock Township.[84] PADEP inspectors "…discovered that the well casings on some of Cabot's natural gas wells were cemented improperly or insufficiently, allowing natural gas to migrate to groundwater...DEP ordered Cabot to cease hydro fracking natural gas wells throughout Susquehanna County."[85] In April 2010, under its consent order and agreement with PADEP, Cabot was required to plug three leaking wells that contaminated the groundwater and drinking water supplies of 14 homes in the region.[86]

In 2011, PADEP issued a cease and desist order to Catalyst Energy, Inc. that prohibited the company from conducting drilling and hydraulic fracturing operations, after a PADEP investigation confirmed that private water supplies serving two homes had been contaminated by natural gas and elevated levels of iron and manganese from Catalyst's operations.[87]

In May 2011, PADEP determined that improper well casing and cementing in Chesapeake Energy Corporation's shallower wells allowed migration into groundwater and caused contaminated 16 families' drinking water supplies in Bradford County.[88]

Pennsylvania has found that significant planning and research is needed to identify orphaned and improperly abandoned wells before drilling nearby wells. At a 2009 Stray Gas Workshop in Pennsylvania, Garrett Velosi, from the National Energy Technology Laboratory, pointed out that one of the main problems with stray gas leaks from abandoned wells is verifying the location of improperly abandoned wells. Records on older wells are often limited or non-existent. Mr. Velosi presented methods for locating unmarked abandoned wells. They include the use of historic photos, ground magnetic surveys, and airborne surveys (equipped with magnetometers and methane detectors).[89]

In January 2011, NYS' consultant Alpha Geoscience agreed that timely well plugging and abandonment requirements are important; however, it recommended that establishing "a specific timeline for plugging and abandonment is neither practical nor necessary."[90] Alpha Geoscience did not examine the large backlog of improperly abandoned wells in NYS or the risk of groundwater contamination from improperly abandoned wells located within the radius of influence of new gas wells and HVHF operations. Alpha Geoscience did not recommend any improved P&A procedures, despite NYCRR's outdated requirements. 6 NYCRR § 555.5 requires only 15' cement plugs, as compared to Texas, Alaska, and Pennsylvania regulations that require a series of 50'-200' cement plugs at various locations within the wellbore.

[84] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[85] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[86] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=10586&typeid=1.

[87] DEP Orders Catalyst Energy to Stop Operations at Gas Wells in Forest County Village, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=16894&typeid=1.

[88] DEP Fines Chesapeake Energy More Than $1 Million, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=17405&typeid=1.

[89] Veloski, G., National Energy Technology Laboratory, Methods for Locating Wells in Urban Areas – A Summary of Case Studies, Pennsylvania Stray Gas Workshop, November 2009.

[90] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA, January 20, 2011

HCLLC disagrees with Alpha Geoscience's recommendation to NYSDEC. Alpha Geoscience's recommendation also conflicts with prior advice from ICF to NYSERDA. HCLLC finds that it is practical and necessary to properly abandon wells on a reasonable timeline, and recommends that NYCRR be improved to include best practices and techniques for permanent wellbore abandonment.

2011 RDSGEIS: The 2011 RDSGEIS document is inconsistent on its recommendations for P&A'ing wells. In Chapter 5, NYSDEC concludes that no improvements are needed in the NYCRR regulations, but proposes changes to improve the regulations at 6 NYCRR § 555.5. In Chapter 6, NYSDEC concludes that it is not possible for HVHF treatments to intersect improperly abandoned wells; yet, in Chapter 7 NYSDEC proposed mitigation to address this very risk. These inconsistencies are further explained below, with recommendations for resolving them.

Chapter 5 of the RDSGEIS concludes that well plugging procedures and requirements in the existing NYCRR (described in the 1992 GEIS) are sufficient to address the risk of improperly abandoned wells. The 2011 RDSGEIS states:

> *As described in the 1992 GEIS, any unsuccessful well or well whose productive life is over must be properly plugged and abandoned, in accordance with Department-issued plugging permits and under the oversight of Department field inspectors.* ***<u>Proper plugging is critical for the continue protection of groundwater, surface water bodies and soil.</u>*** *Financial security to ensure funds for well plugging is required before the permit to drill is issued, and must be maintained for the life of the well [emphasis added].*[91]
>
> *When a well is plugged, downhole equipment is removed from the wellbore, uncemented casing in critical areas must be either pulled or perforated, and cement must be placed across or squeezed at these intervals to ensure seals between hydrocarbon and water-bearing zones. These downhole cement plugs supplement the cement seal that already exists at least behind the surface (i.e., fresh-water protection) casing and above the completion zone behind production casing.*
>
> *Intervals between plugs must be filled with a heavy mud or other approved fluid. For gas wells, in addition to the downhole cement plugs, a minimum of 50 feet of cement must be placed in the top of the wellbore to prevent any release or escape of hydrocarbons or brine from the wellbore. This plug also serves to prevent wellbore access from the surface, eliminating it as a safety hazard or disposal site. Removal of all surface equipment and full site restoration are required after the well is plugged.*
>
> *The plugging requirements summarized above are described in detail in Chapter 11 of the 1992 GEIS and are enforced as conditions on plugging permits. Issuance of plugging permits is classified as a Type II action under SEQRA. Proper well plugging is a beneficial action with the sole purpose of environmental protection, and constitutes a routine agency action.* ***<u>Horizontal drilling and high-volume hydraulic fracturing do not necessitate any new or different methods for well plugging that require further SEQRA review</u>*** *[emphasis added].* [92]

[91] 2011 NYSDEC, RDSGEIS, Page 5-143.

[92] 2011 NYSDEC, RDSGEIS, Page 5-144.

While NYSDEC agrees that proper well P&A is critical to the protection of groundwater, surface water, and soil, it concludes that horizontal drilling and HVHF shale gas wells do not require any new or different P&A methods. However, this conclusion is inconsistent with NYSDEC's proposed revisions to the P&A procedures at 6 NYCRR § 555.5, this proposal suggests that the existing regulations do not represent best practices.

Recommendation No. 22: The SGEIS should be revised to state that the existing P&A procedures at 6 NYCRR § 555.5 were determined to be outdated and not best practice and that NYSDEC has proposed revisions. The basis for NYSDEC's proposed revisions should be justified in the SGEIS, and include a review of other states' best practices for P&A.

Chapter 5 of the RDSGEIS does not address: (1) whether NYS has a backlog of wells requiring P&A in close proximity to drinking water sources; (2) whether NYS has a backlog of wells requiring P&A in close proximity to areas under consideration for HVHF treatments; (3) whether a procedure needs to be put in place to examine the number, type, and condition of wells requiring P&A in close proximity to new shale gas development; and (4) whether plugging improperly abandoned and orphaned wells should be required where such wells are in close proximity to new HVHF treatments.

Recommendation No. 23: The SGEIS should examine: the number of improperly abandoned or orphaned wells in NYS requiring P&A in close proximity to drinking water sources or in close proximity to areas under consideration for HVHF treatments; whether a procedure needs to be put in place to examine the number, type, and condition of wells requiring P&A in close proximity to new shale gas development; and whether plugging improperly abandoned and orphaned wells should be required where such wells are in close proximity to new HVHF treatments.

For example, maps showing the location and depth of NYS' temporarily abandoned, improperly abandoned, or orphaned wells could not be located; however, this data is needed to ensure safe development of shale gas resources. The RDSGEIS proposes that operators identify any existing well listed in NYSDEC's Oil & Gas database within one mile of the proposed HVHF well[93]; however, ICF's 2003 report to NYSERDA points out that there are a large number of old wells in NYS where location or well condition data is not available in NYSDEC's Oil & Gas database. If NYSDEC has improved the Oil & Gas database to accurately document all existing wells this information should be included in the SGEIS and maps of the wells should be made available.

Recommendation No. 24: The SGEIS should include maps showing the location and depths of improperly abandoned, orphaned wells in NYS. These maps should correlate the locations and depths to potential foreseeable shale gas development and examine the need to properly P&A these wells before shale gas development occurs nearby. The SGEIS should assess the risk of a HVHF well intersecting a well that is not accurately documented in NYSDEC's Oil & Gas database and whether this poses and unmitigated significant impact to protected groundwater resources.

In Chapter 6 of the RDSGEIS, NYSDEC discounts the risks of new HVHF shale gas wells communicating with nearby abandoned wells. NYSDEC relies on its consultant's (ICF) analysis that concludes it is not possible for HVHF treatments to intersect with improperly abandoned wells.[94] Yet, in Chapter 7, NYSDEC recommends precautionary measures to be taken by operators to ensure that wells

[93] 2011 NYSDEC, RDSGEIS, Page 3-10 and Page 7-72.

[94] 2011 NYSDEC, RDSGEIS, Page 6-52.

near HVHF operations are properly P&A'd to prevent freshwater contamination. The RDSGEIS is internally inconsistent on this point and the two diametrically opposed conclusions need reconciliation.

Recommendation No. 25: Chapter 6 of the SGEIS should be revised to be consistent with and support the Chapter 7 recommendation for HVHF operators to ensure all nearby wells are properly P&A'd before HVHF operations are conducted to mitigate the risk of HVHF treatments intersecting improperly abandoned wells. This requirement should also be codified in NYCRR.

In 2009 HCLLC recommended that preventative measures be taken to identify and properly abandon existing wells before proceeding with nearby shale gas drilling and HVHF operations. NYSDEC responded favorably to this recommendation by proposing that the operator identify any existing well listed in NYSDEC's Oil & Gas database within one mile of the proposed HVHF well[95] and by proposing that any improperly abandoned wells be plugged within that one-mile radius.[96] While NYS' recommendation is a step in the right direction, additional analysis is needed to justify the one-mile radius selected.

The RDSGEIS does not provide data on the maximum horizontal fracture propagation length that could occur at NYS' proposed 2000' depth cut-off. The RDSGEIS assumes the maximum horizontal well length will be 4000'. However, as highlighted in other sections of this report, current horizontal drilling technology allows for wells to be drilled substantially longer than 4000'. Fractures induced along that horizontal wellbore section can propagate several thousand feet from the well, depending on fracture treatment design parameters. Therefore, the wellbore length and the maximum fracture length combined could result in a radius of influence of more than one mile (5,280').

Recommendation No. 26: The SGEIS should provide technical justification for selecting a one-mile wellbore intersection radius and should explain the maximum horizontal drilling length and horizontal fracture length that corresponds with the proposed one-mile radius. This will be especially important for shallower wells where fractures tend to propagate on a horizontal plane, and where there will be a large number of potential shallow well intersection possibilities.

The SGEIS should examine the potential for longer wellbores and large fracture influence zones to occur now or in the future, and a wellbore intersection radius that corresponds to the largest areas of influence that are reasonably foreseeable should be included in the SGEIS as a mitigation measure and be codified in the NYCRR. Alternatively, if NYSDEC selects a one mile radius, the SGEIS should limit drilling length and horizontal fracture length in the SGEIS as a mitigation measure and in the NYCRR to ensure that the radius of influence does not extend beyond the one-mile impact area proposed.

The RDSGEIS proposes, in Table 11.1, that operators identify and plug wells within a one-mile radius, but this requirement is not translated into a permit condition or codified in NYCRR. Table 11.1 proposes:

> *Operators must identify and characterize any existing wells within the spacing unit and within one mile of proposed well and* ***plug and abandon any well which is open to the target formation or is otherwise and immediate threat to the environment*** *[emphasis added].*[97]

[95] 2011 NYSDEC, RDSGEIS, Page 3-10 and Page 7-72.

[96] 2011 NYSDEC, RDSGEIS, Table 11.1, Page 11-5.

[97] 2011 NYSDEC, RDSGEIS, Table 11.1, Page 11-5.

Appendix 6, PROPOSED Environmental Assessment Form Addendum requires the operator to complete the one-mile radius of investigation, yet, there is no requirement in Appendix 10 or in the NYCRR requiring the offset wells to be plugged by the HVHF operator if needed.

In direct contrast to the conclusions reached in Chapter 6, Chapter 7 of the RDSGEIS acknowledges the potential risk of HVHF wells intersecting improperly abandoned wells and proposes a process to address these risks:

> ***To ensure that abandoned wells do not provide a conduit for contamination of fresh water aquifers, the Department proposes to require that the operator consult the Department's Oil and Gas database as well as property owners and tenants in the proposed spacing unit to determine whether any abandoned wells are present. If (1) the operator has property access rights, (2) the well is accessible, and (3) it is reasonable to believe based on available records and history of drilling in the area that the well's total depth may be as deep or deeper than the target formation for high-volume hydraulic fracturing, then the Department would require the operator to enter and evaluate the well, and properly plug it prior to high-volume hydraulic fracturing if the evaluation shows the well is open to the target formation or is otherwise an immediate threat to the environment.*** *If any abandoned well is under the operator's control as owner or lessee of the pertinent mineral rights, then the operator is required to comply with the Department's existing regulations regarding shut-in or temporary abandonment if good cause exists to leave the well unplugged. This would require a demonstration that the well is in satisfactory condition to not pose a threat to the environment, including during nearby high-volume hydraulic fracturing, and a demonstrated intent to complete and/or produce the well within the time frames provided by existing regulations [emphasis added].*[98]

While Chapter 7 correctly acknowledges the need for P&A procedure improvement and review of nearby abandoned wells before HVHF treatments, NYSDEC incongruously proposes to limit P&A due diligence to: 1) wells that are within the HVHF well operator's control and 2) wells that are "accessible." This approach discounts the risks posed by improperly abandoned wells that are owned by another operator, orphaned, or difficult to access.

The inconsistency in P&A improvement recommendations persists in the Appendix 10 HVHF Permit Conditions where the recommended improvements in Chapter 7 are not included. The Chapter 7 recommendations are not included in the revised NYCRR either.

[98] 2011 NYSDEC, RDSGEIS, Page 7-58.

Recommendation No. 27: If a well was not properly P&A'd to current standards, the operator should be required to work with the well owner or take the initiative itself to ensure the well is properly P&A'd before new drilling begins and before a nearby HVHF treatment occurs. Approval of a HVHF well application should be conditioned on verification that any necessary P&A work is complete. This requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

NYSDEC should consider requiring operators to use a variety of proven methods to locate unmarked, abandoned wells, including: historic photos, ground magnetic surveys, and airborne surveys (equipped with magnetometers and methane detectors).

The proposed mitigation measure, requiring improperly abandoned or orphaned wells to be plugged prior to a HVHF treatment, should be included in Appendix 10, of the SGEIS and codified in the NYCRR.

Additionally, NYSDEC should request ICF to further examine additional technical and scientific questions that were not addressed in its analysis.

Foremost, ICF's report does not indicate that ICF evaluated the difference in reservoir pressure near a new shale gas wellbore, drilled into an un-depleted higher pressure gas reservoir, as compared to the lower reservoir pressure in the drainage radius around a well that previously served or is currently serving as a production well. The reservoir pressure in the drainage radius around a production well will be substantially lower creating a pressure sink around that well. By the laws of physics, gas and fluid will flow from higher pressure regimes to lower pressure regimes. Therefore, if a HVHF treatment intersects the drainage radius around a nearby pressure-depleted reservoir connected to an improperly abandoned well, the HVHF fluid and associated mobilized gas will continue to move towards the improperly abandoned well, not back to the new shale gas well as ICF suggests.

As explained in Chapter 10 of this report, industry data shows that HVHF treatments are propagating well beyond the shale zone into formations located above and sometimes below the shale, meaning that the HVHF treatment can potentially intersect the depleted well drainage area of a well that has produced from a zone above or below the shale.

However, ICF concludes that, once the HVHF treatment pressure ceases, all HVHF fluid will return to the shale gas well, and there is no possibility that HVHF fluid or associated mobilized gas will travel up an improperly abandoned well conduit. This conclusion is based on the assumption that the lowest pressure pathway for HVHF fluids injected into the formation is back to the shale gas well, but such assumption does not account for the possibility that a lower pressure regime at an abandoned or active well site could influence the flow of HVHF fluids and newly mobilized gas. It also discounts the possibility that other lower pressure intervals could be located above or below the shale zone that would preferentially accept HVHF fluids and gas mobilized during the treatment.

In these cases, HVHF fluids and gas would continue towards the improperly abandoned well and up the well conduit until pressure equilibrium is reached or into adjacent lower pressured reservoirs. This could result in HVHF fluids and associated gas that is mobilized during the HVHF treatment contaminating groundwater if an exposure pathway exists in the improperly abandoned well or from an adjacent lower pressure reservoir to a shallower protected water zone.

While it is true that HVHF fluids will flow back to the new shale gas well if such well presents the lowest pressure regime for fluid to flow to, this will not always be the case, as evidenced by the fact that not all the HVHF fluid returns to the well. The RDSGEIS states that:

> *Flowback water recoveries reported from horizontal Marcellus wells in the northern tier of Pennsylvania range between 9 and 35 percent of the fracturing fluid pumped. Flowback water volume, then, could be 216,000 gallons to 2.7 million gallons per well, based on a pumped fluid estimate of 2.4 million to 7.8 million gallons, as presented in Section 5.9.*[99]

Therefore, several million gallons of HVHF treatment fluid remain in the reservoir and will travel to the lowest pressure formation/regime present, including such lower pressure regimes present around nearby existing wells that have previously produced hydrocarbons. An out-of-zone HVHF, as described in Chapter 10 of this report could potentially connect with this lower pressure reservoir, if not properly designed and implemented.

Secondly, ICF's analysis did not examine the maximum horizontal distance a HVHF could travel, nor identify minimum safe separation distances between horizontal fractures and abandoned wells. Thus, ICF did not attempt, to compare the maximum HVHF length to the closest distance that an abandoned well may occur.

Instead, ICF's analysis assumes that the HVHF impact radius would always be less than the distance to a nearby well (which may not be true in all cases, and will depend on reservoir characteristics and job design). ICF concludes, without basis, that a fracture created by a HVHF would never intersect a nearby well, but does not establish the well spacing distance required for this to be true nor does it consider the fact that Marcellus Shale fractures (as shown in Chapter 10 of this report) do routinely propagate out of zone.

Additionally, the Chapter 6 conclusion that it is not possible for a HVHF treatment to intersect an improperly abandoned well is discordant with three cases cited in PADEP's 2009 Report that document situations in which fracture stimulations in operating wells communicated with nearby abandoned wells, causing gas leaks in the abandoned wells.[100] PADEP's cases confirm that fracture stimulations, if improperly designed and executed, can intersect improperly abandoned and orphaned wells.

Recommendation No. 28: The SGEIS and NYCRR should require HVHF well operators to identify previously drilled wells that may be located within the hydraulic radius of the new shale gas well that may be affected during a HVHF treatment. The operator should be required to estimate the maximum horizontal and vertical extent of the fracture length that will be propagated and ensure that there are no abandoned or improperly abandoned wells in that intersection radius. An additional safety factor should be applied in this analysis to account for uncertainty in fracture design and implementation, and the potential for the actual fracture length to be longer than estimated (e.g. a conservative analysis is needed).

The HVHF treatment size should be designed to ensure that it does not intersect with any abandoned or improperly abandoned wells, with an additional margin of safety.

[99] 2011 NYSDEC, RDSGEIS, Page 5-99.

[100] "Stray Natural Gas Migration Associated with Oil and Gas Wells" Draft Report. PADEP, Bureau of Oil and Gas Management. October 28, 2009.

> Any improperly abandoned wells nearby, and just outside, the intersection radius should be properly abandoned to current standards before new drilling begins and before the HVHF treatment occurs.

NYCRR Proposed Revisions: Despite the 2011 RDSGEIS conclusion that no new P&A requirements are needed, and NYSDEC's consultant's (Alpha Geoscience) recommendation that no improvements are necessary, NYSDEC proposed revisions to its existing well P&A requirements at 6 NYCRR § 555.5, Plugging Methods, Procedures and Reports:

(a) The plugging of a well shall be conducted in accordance with the following sequence of operations[:] ***<u>. The Division at its discretion may require the tagging of all plugs and require casing and/or cement evaluation logs to be run to determine proper plugging procedures. The following are minimum requirements for plugging and the department may impose additional requirements</u>****: [emphasis added]*

> *(1) The well bore, whether to remain cased or uncased, shall be filled with cement from total depth to at least [15] <u>50</u> feet above the top of the shallowest formation from which the production of oil or gas has ever been obtained in the vicinity. Alternatively, a bridge topped with at least [15] <u>50</u> feet of cement shall be placed immediately above each formation from which the production of oil or gas has ever been obtained in the vicinity.*
>
> *(2) [If] <u>For</u> any casing [is to be] left in the ground, a cement plug of at least [15] <u>100</u> feet in length shall be placed [at the bottom of such section of casing] <u>50 feet inside and 50 feet outside of the casing shoe</u> . <u>Uncemented casing must be pulled as deep as practical with a 50-foot plug placed in and above the stub of the casing. If the uncemented casing is unable to be pulled the casing must be ripped or perforated 50 feet below the shoe of the next outer casing and a 100-foot plug placed across that shoe</u>. A [similar] <u>50 foot</u> plug shall be placed at [the top of such section of casing unless it shall extend to]the surface. [In the latter event, the casing shall be capped in any such manner as will prevent the migration of fluids and not interfere with normal soil cultivation.]*
>
> *(3) If casing extending below the deepest potable fresh water level shall not remain in the ground, a cement plug of at least [15] <u>50</u> feet in length shall be placed in the open hole at a position approximately 50 feet below the deepest potable fresh water level.*
>
> *(4) If the conductor casing or surface casing is drawn, a cement plug of at least [15] <u>50</u> feet in length shall be placed immediately below the point where the lower end of the conductor or surface casing shall previously have rested. The hole thereabove shall be filled with cement, sand or rock sediment or other suitable material in such a manner as well prevent erosion of the well bore area and not interfere with normal soil cultivation.*
>
> *(5) The interval between all plugs mentioned in paragraphs (1) through (4) of this subdivision shall be filled with [a heavy mud-laden] <u>gelled fluid with a minimum density equal to 8.65 pounds per gallon with a 10 minute gel-shear strength of 15.3 to 23.5 pounds per hundred square feet</u> or other <u>department</u> approved fluid.*

NYSDEC's proposed revisions are a step in the right direction. Overall, NYSDEC proposes to require longer cement plugs, weighted mud, and some additional QA/QC procedures, including tagging the cement plugs and possibly running cement evaluation logs.

NYSDEC's existing P&A regulations require short cement plugs (15'), which are woefully inadequate, compared to current best practices of installing a series of 50'-200' cement plugs within a wellbore, and removing corroded casings to isolate water resources. Unfortunately, this means that most of NYS' abandoned wells, if plugged to NYCRR's existing standards, are not likely to provide adequate groundwater protection. To address this problem, the P&A procedures used in each previously abandoned well, located near a proposed new HVHF well should be carefully examined for adequacy to determine whether the well should be re-abandoned to current, more robust P&A standards.

Recommendation No. 29: P&A procedures used in each previously abandoned well, located near a proposed new HVHF well should be carefully examined for adequacy to determine whether the well should be re-abandoned to current, more robust P&A standards and this requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

NYSDEC's proposed increase to 50' cement plug length is an improvement; however, best practices used in other states such as Texas, Alaska, and Pennsylvania require longer cement plugs. NYSDEC should consider enhancing the regulations to require longer and additional cement barriers to ensure that hydrocarbons and freshwater are confined to their respective indigenous strata, and are prevented from migrating into other strata or to the surface. For example, while NYSDEC has proposed to revise the NYCRR to require a 50' cement barrier, Alaska requires double that protection at 100'.[101] Pennsylvania recently upgraded its P&A requirements from its previous 50' standard to plugs of 50'-100'.[102] Texas requires cement plugs ranging from 50'-200' at numerous locations in the well, and requires cement QA/QC procedures.[103] For example, Texas requires each cement plug to be a minimum of 200' in length and extend at least 100' below and 100' above the top of each hydrocarbon stratum and the base of the deepest protected water stratum, which is a substantial difference from NYS' current requirement for 15' plugs.

Recommendation No. 30: The SGEIS mitigation measures and NYCRR should be revised to clearly specify that:

Plugging a wellbore should be performed in a manner that ensures all hydrocarbons and freshwater are confined to their respective indigenous strata, and prevented from migrating into other strata or to the surface.

All hydrocarbon-bearing strata should be permanently sealed off by installing a cement barrier at least 100 feet below the base to at least 100 feet above the top of all hydrocarbon-bearing strata (200' plug).

The plugging of a well should include effective segregation of uncased and cased portions of the wellbore to prevent the vertical movement of fluid within the wellbore. A continuous cement plug must be placed from at least 100 feet below to at least 100 feet above the casing shoe (200' plug).

The operator should be required to submit records to NYSDEC to demonstrate that the well is P&A'd in compliance with regulations.

NYSDEC should consider specifying the grade of cement required to plug the well. It should also consider requiring the use of gas blocking agents.

[101] 20 AAC 25.

[102] PA Code, § 78.91.

[103] 16 TAC Part 1, § 3.14.

Revisions to the NYCRR include some improved QA/QC procedures, but these revisions are loosely written and do not specify when QA/QC procedures will be mandatory. For example, it is best practice to tag all cement plugs to verify placement depth; this should not be an optional, discretionary procedure. Also, NYSDEC should specify under what circumstances a cement evaluation tool will be required.

Recommendation No. 31: The SGEIS mitigation measures and NYCRR should be revised to require cement quality standards, including the use of gas blocking cement. The SGEIS and NYCRR should require tagging of all cement plugs and provide instructions on when additional cement evaluation tools must be run.

10. HVHF Design and Monitoring

Background: In 2009, HCLLC recommended that NYSDEC revise its regulations to specify and require best technology and best practices for collecting data, and modeling, designing, implementing, and monitoring a fracture treatment, including:

(a) Collecting additional geophysical and reservoir data to support a reservoir simulation model;

(b) Developing a high-quality Marcellus Shale 3D reservoir model(s) to safely design HVHF treatments;

(c) HVHF modeling prior to each fracture treatment to ensure that the fracture is contained to the Marcellus Shale zone;

(d) Careful monitoring of the fracture treatment, including shutting the treatment down if data indicates casing leaks or out-of-zone fractures;

(e) Starting with smaller fracture treatments in the deepest, thickest sections of the Marcellus Shale to gain data and experience (e.g. 4,000' deep and 150' thick);[104]

(f) Using the experience gained with fracture testing on deeper sections of the Marcellus to design and implement larger treatment volumes over time (potentially allowing increasingly shallower and thinner intervals *only* if technical data supports the safety of this technique); and

(g) Documenting, reporting, and remediating fracture treatment failures to ensure drinking water protection.

In 2009, HCLLC recommended that fracture treatments be carefully monitored and shut down if pressure data indicates casing leaks. HCLLC noted the American Petroleum Institute recommends continuous and careful monitoring of surface injection pressure, slurry rate, proppant concentration, fluid rate, and sand or proppant rate, [105] and that fracture treatments should be immediately shutdown if abnormal pressures indicate a casing leak. The 2011 RDSGEIS now requires the operator to carefully monitor fracture treatments and shut down the treatment if data indicates casing leaks or out-of-zone fractures. This is an important improvement to the SGEIS.

Experts agree that Marcellus Shale gas production can be maximized by: 1) drilling long horizontal wells to increase the drainage area and 2) conducting hydraulic fracture treatments to improve permeability and access to trapped gas. However, successful, safe development requires hydraulic fracture treatments be properly designed and sized to remain within the shale zone. Fracture treatments that propagate outside the shale zone (fracturing out-of-zone) reduce gas recovery and risk pollutant transport. There is extensive industry literature on the importance of hydraulic fracture design, modeling, and field verification to optimize fracture stimulation. Therefore, in 2009 HCLLC recommended that the DSGEIS be improved to provide additional technical and scientific data and require specific mitigation, ensuring that operators are designing jobs that will not fracture out-of-zone.

[104] Smaller, deeper fracture treatments could be used initially in NYS, the performance examined, the predictive model improved based on that data, and then fracture treatment size and proximity to protected waters and other wellbores could be modified, as confidence increases in the predictive ability of the model to ensure a safe and favorable result.

[105] American Petroleum Institute (API) Guidance Document HF1, Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines, October 2009.

Pollutant transport and pollutant toxicity issues are addressed in Dr. Tom Myers' and Dr. Glenn Miller's reports to NRDC on the 2009 DSGEIS and the 2011 RDSGEIS. HCLLC's recommendations center on what type of data, analysis, tools, and methods an engineer/operator should have in place and use to ensure that a fracture treatment can be contained within the Marcellus Shale zone.

In 2009, HCLLC observed that NYSDEC and/or operators had not provided sufficient data to demonstrate that a HVHF treatment can be contained to the Marcellus Shale. HCLLC pointed out that the 2009 DSGEIS did not require the operator to demonstrate that it is equipped with sufficient expertise, training, qualifications, and engineering tools to safely design, implement, and assess the performance of HVHF treatments. HCLLC recommended that NYSDEC consider operator qualifications.

HCLLC's recommendations on the 2009 DSGEIS explained that it is best practice in newly developed formations, such as the NYS Marcellus Shale, to build hydraulic fracture models. Fracture models are used by engineers to safely design fracture treatments. During actual fracture stimulation treatments, data are collected to verify model accuracy, and the model is continually refined to improve its predictive capability.

Because fracture treatments may be executed several thousand feet below the surface of the earth, and can only be indirectly observed, it is important for engineers to have a 3D model to guide design. While 3D modeling is not an exact science, the model provides an engineer with an estimating method for predicting both horizontal and vertical fracture length.

As further explained below, data collected during drilling, well logging, coring, and other geophysical activities and HVHF implementation can be used to continuously improve the model quality and predictive capability.

In newly developed areas it is important to conduct initial HVHF treatments in the lowest risk zones, far below protected aquifers and with large horizontal offsets from existing wells. Until the predictive capability of site-specific models improves from the input of actual field data, larger buffer zones should be used. Absent hydraulic fracture modeling in newly developed areas such the NYS Marcellus Shale, engineers would blindly be making decisions on the size, type, and execution of HVHF treatments.

NYS' consultant, Alpha Geoscience, agreed with HCLLC's 2009 recommendations and in January 2011 reported to NYSDEC that:

> *Harvey Consulting's [HCLLC] assessment of the dSGEIS' discussion of hydraulic fracture design and monitoring is thorough…*
>
> *Harvey Consulting has thoroughly documented its discussion of hydraulic fracture design and monitoring, citing professional journal articles, professional conference papers, technical guidance documents, and consultant reports.*[106]

Alpha Geoscience recommended to NYSDEC that HCLLC's 2009 recommendations be included in the SGEIS:

> *Harvey Consulting's ideas should be considered for inclusion in the dSGEIS as possible permit conditions, especially for the first wells drilled in an area.*[107]

[106] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA, January 20, 2011, Pages 26-27.

[107] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC, December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 28.

While Alpha Geoscience's report acknowledges the importance of proper HVHF design and monitoring, it includes several misrepresentations about HCLLC's 2009 comments that require correction.

First, Alpha Geoscience incorrectly contends that HCLLC recommended industry and NYS develop separate hydraulic fracture models; this is not correct. HCLLC recommended that industry develop models, **or** that joint model funding be implemented as a more cost-effective approach. Typically, companies build their own proprietary models to seek competitive advantage, especially in newly developed areas where the models are used as part of the competitive bidding process. However, it is possible for one or more companies to pool resources to develop a joint model as a cost savings.

Second, Alpha Geoscience incorrectly contends that HCLLC recommended that every operator perform fracture modeling at every location, **including locations that have been thoroughly modeled and assessed.** Alpha Geoscience concluded that this would be extremely costly compared to the technical value. HCLLC did not recommend HVHF modeling be conducted at locations that have been "thoroughly modeled and assessed." Logically, if this work has already been completed, there is no reason to repeat it.

HCLLC did recommend that NYSDEC require operators to complete modeling prior to each fracture treatment to ensure that the fracture is properly designed and planned to be contained to the Marcellus Shale zone. This is not a significant amount of work per well for experienced operators, with working models. HCLLC also recommended that operators collect data during fracture treatments to further refine hydraulic fracture models. HCLLC pointed out that as NYS shale development is in its infancy, hydraulic fracture model work has not yet been completed, and therefore is needed.

Once a hydraulic fracture model is built and populated with data specific to the NYS Marcellus Shale, running a well-specific HVHF treatment scenario is an efficient process, and an important quality control and quality assurance measure. It does not appear that Alpha Geoscience is familiar with the reservoir simulators used for oil and gas work, because their recommendation to construct a hydraulic fracture model for the Marcellus Shale, and then use it only on the initial wells constructed, is inconsistent with industry practice. Model quality improves over time. As additional data is collected and the model is refined, it becomes an increasingly valuable tool to the operator. High-quality models are an essential tool for designing fracture treatments in challenging circumstances and locations.

In 2009, HCLLC explained that industry agrees there is a high level of uncertainty in NYS Marcellus Shale development; industry recommends engineering and geophysical data work to reduce that uncertainty. HCLLC's recommendations in 2009 stated:

> ***Marcellus Experience Very Limited:*** *Marcellus Shale gas development has a high level of uncertainty. Shales by nature are very heterogeneous.*[108] *Industry has limited experience exploiting the Marcellus Shale using horizontal wells and slickwater fracs. The first Appalachian Basin Marcellus Shale gas well stimulation using high-volume slickwater fracture treatments was only recently performed in Southwestern Pennsylvania in 2004.*[109] *Therefore, industry has less than five years of experience developing the Marcellus Shale using the techniques proposed in the dSGEIS.*

[108] Cipolla, C.L., Lolon, E.P., and Mayerhofer, M.J., Reservoir Modeling and Production Evaluation in Shale-Gas Reservoirs, International Petroleum Technology Conference, Paper 13185, December 2009.

[109] Fontaine, J., Johnson, N., and Schoen, D., Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History, Society of Petroleum Engineers Paper 117772, October 2008.

Even NYSDEC's consultants acknowledge that industry literature on and experience with the Marcellus Shale is so limited that most of their analysis was based on development of other shale gas reservoirs, such as the Barnett and Fayetteville. NYSDEC's consultant, ICF, states that:

> *"**Drilling operations, and especially multi-horizontal wells, are relatively new in Marcellus Shale**. While drilling operations are underway in neighboring states as evidenced by over 450 wells in Pennsylvania for example, **technical studies have yet to be published** that quantify actual drilling operations in Marcellus Shale. **For the most part, we have had to make assumptions, where technically appropriate, that drilling operations in other shale formations are representative of expected Marcellus operations** [emphasis added].*[110]

Lack of Marcellus Shale experience increases the risk of fracturing out-of-zone, unless a conservative, step-wise approach is taken to better understand the Marcellus Shale before large scale development occurs in NYS.

***NYS Marcellus Data Set Improvement Needed**: Site-specific data, unique to the Marcellus Shale in NYS, must be collected to: better understand the reservoir heterogeneities; develop sophisticated three dimensional (3D) reservoir models to more accurately design fracture treatments; and examine actual fracture performance in the field. Reservoir simulation models are critical engineering design tools. The dSGEIS provides no indication that a model exists for the NYS Marcellus Shale.*

Engineers use 3D models to predict fracture height, length, and orientation prior to actually performing the job at the well. The goal is to design a stimulation treatment that optimizes fracture networking and maximizes gas production, while confining fracture growth to within the gas shale target formation.[111]

Engineers examine various parameters (e.g., volume, pressure, treatment placement) to optimize a fracture treatment. Without a high-quality 3D reservoir simulation model to design a fracture treatment, operators cannot demonstrate to NYSDEC that the fracture is predicted to stay in zone.

Typically an operator would start by collecting core analysis, well logs, and other subsurface data in the area it is interested in developing, to populate a site-specific 3D reservoir model. To collect this data, additional exploration and appraisal wells must be drilled (see recommendation No. 2). The limited amount of special core analysis and core data on the Marcellus Shale, as well as overlying intervals, is described in Chapter 4 of the DSGEIS, showing a need for additional data.

***Test in Deepest, Thickest Zones First:** NYSDEC is proposing to allow high-volume fracture treatments, without requiring the standard of care a petroleum engineer would typically use to collect data, and model, design, and monitor fracture treatments. NYSDEC should require that additional data be collected to support a model, and initially it should only allow a few, small fracture treatments that are conducted with intensive monitoring to verify that they are designed and implemented to stay within the*

[110] 2009 NYSDEC, DSGEIS, ICF Task 2 Report, Page 1.

[111] ALL Consulting, Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale, Presented at The Ground Water Protection Council 2008 Annual Forum, Cincinnati, Ohio, September 21-24, 2008.

> *Marcellus Shale. This data gathering and testing should be conducted in the deepest portions of the Marcellus Shale (below 4,000') and in the thickest section of the shale (over 150') to ensure there are adequate buffer zones to protect the environment during the data gathering and testing process. Operators should start with smaller fracture treatment sizes, collecting field data to better understand fracture performance, and use field data to calibrate that performance in the 3D model.*
>
> *Over time, with careful analysis and a conservative, step-wise approach, larger fracture treatments can be tested and carefully monitored. Over time it may be possible to safely use the treatments on thinner reservoirs and shallower reservoirs, but certainly not as a first step. High-volume fracture treatments should not be conducted until there is a sophisticated data set, model, and monitoring program to verify pre-fracture and post-fracture reservoir properties.*
>
> ***Buffer Zones Needed:*** *Vertical fractures that extend above and below the shale zone will decrease gas recovery rates by allowing vertical migration into the overlying strata, or by allowing water influx from aquifers above or below the shale. NYS has a financial incentive to ensure fracture treatments are conducted correctly, because NYS will want to maximize its royalty share and tax revenue.*
>
> *To avoid fracturing out-of-zone, engineers typically design fracture treatments with a buffer zone (an un-fractured zone at the top of the shale layer and at the base of the shale). Buffer zone size should increase with geologic and technical uncertainty. Buffer zone size may decrease as industry gains experience and data quality/quantity improves. The DSGEIS does not contain sufficient information to demonstrate that NYSDEC and/or operators proposing high-volume fracture treatments have developed engineering tools capable of computing a safe buffer zone.*

Third, Alpha Geoscience incorrectly contends that HCLLC recommended that every operator perform a minifracture treatment at every location, including locations that have been thoroughly modeled and assessed. HCLLC did not recommend that a minifracture be conducted at every well. Instead, HCLLC recommended that minifractures be conducted in a few different areas of NYS to further refine hydraulic fracture models. HCLLC's 2009 recommendations stated:

> *Technology is available to assess actual fracture growth including: minifracs,[112] microseismic fracture mapping,[113] tilt surveys, well logging (e.g., tracer and temperature surveys[114]), etc.[115] These technologies can be used to provide more accurate assessments of the locations, geometry, and dimensions of a hydraulic fracture system.[116]* ***<u>This data</u>***

[112] Minifracs are small fracture treatments conducted in the well to better understand fracture conductivity and flow geometry prior to implementing a large fracture treatment. Minifracs are typically used to optimize the fracture design and calibrate the fracture model. These tests involve periods of intermittent injection followed by intervals of shut-in and/or flowback. Pressure and rate are measured throughout a minifrac and recorded for subsequent analyses.

[113] Microseismic monitoring is a method that measures the seismic wave generated during a fracture treatment to map the fracture extent, and it can be used to make "real-time" changes in the fracture design and implementation program.

[114] After the fracture treatment is completed, an operator can run a temperature log in the well to measure the variation in reservoir temperature resulting from the treatment. The reservoir temperature is hotter than the fracture fluid and proppant. Cooler temperatures will be measured where frac fluid and proppant are placed. Temperature logs will provide insight into fracture location and growth outside the casing.

[115] American Petroleum Institute (API) Guidance Document HF1, Hydraulic Fracturing Operations—Well Construction and Integrity Guidelines, October 2009.

[116] Schlumberger, Microseismic Hydraulic Fracture Monitoring, http://www.slb.com/content/services/stimulation/stimmap.asp.

> ***can be obtained in the Marcellus Shale in a few different areas of NYS to further refine the hydraulic fracture model.*** *Minifractures are particularly helpful in estimating fracture dimensions, fracture efficiency, closure pressure, and leakoff prior to implementing a high-volume, full-scale treatment. NYSDEC should require operators to conduct minifractures to better understand site-specific reservoir characteristics prior to conducting a high-volume fracture treatment [emphasis added].*

HCLLC's 2009 recommendations also noted that:

> ***While NYSDEC's consultant, ICF[117], documents a number of the engineering methods that can be used to model, monitor, and improve fracture treatments, NYSDEC does not require any of these methods in its existing regulations. Absent a regulatory requirement, there is no assurance these methods will be used*** *[emphasis added]*.
>
> *Best practice for hydraulic fracture planning includes a detailed understanding of the in-situ conditions present in the reservoir (e.g., shale thickness, reservoir pressure, rock fracture characteristics, and special core analysis). In highly heterogeneous reservoirs, reservoir simulation is often coupled with stochastic methods (e.g. Monte Carlo analysis and geostatistical techniques) to improve the quality of the 3D reservoir model.[118]*
>
> *Data collected on previous fracture treatments in the Marcellus Shale and drilling data will be useful to refine the fracture modeling. Actual fracture treatments must be carefully monitored and implemented to ensure fractures stay within zone. Data collected during each fracture treatment should be used to calibrate the 3D reservoir model to improve future fracture treatment design.*
>
> *Peer-reviewed articles and technical data on Marcellus Shale vertical fracture growth characteristics are sparse. While fracture growth models exist at an industry level, and have been tuned for fracture treatments in the Barnett Shales and other gas reservoirs, considerable technical work is still needed to develop fracture growth models for NYS Marcellus Shale development.*
>
> *A literature review was completed by the author [HCLLC] in search of a Marcellus Shale 3D reservoir model for NYS; none was found in the petroleum engineering published literature. It is not clear if the lack of a Marcellus Shale reservoir model for NYS indicates that one does not exist, or whether industry is holding models proprietary. Yet in other shale gas developments (e.g., Barnett and Fayetteville) there is extensive industry literature on: available reservoir simulation model; completion and fracture design; and performance assessment to compare predicted fracture growth with that achieved in the field. Lack of industry literature is usually a strong indication that additional data gathering and technology development is needed.*
>
> *The data void for NYS' Marcellus Shale technical literature reinforces the need for NYSDEC to use a conservative, step-wise approach, rather than launching into a massive drilling and fracturing campaign without the data or tools in place to do a safe and effective job.*

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[117] ICF International, Technical Assistance to NYS on DSGEIS, August 2009.

[118] Schepers, K.C., Gonzalez, R.J., Koperna, G.J., and Oudinot, A.Y., Reservoir Modeling in Support of Shale Gas Exploration, Society of Petroleum Engineers, June 2009.

NYSDEC should require additional information be collected by industry to better understand the geological and geophysical properties of the Marcellus Shale zone and the overlying strata between the Marcellus and drinking water aquifers.

NYSDEC should require 3D reservoir simulation models be developed to accurately predict hydraulic fracture treatment performance, and to ensure the jobs are well engineered and designed with adequate safety factors to avoid fracturing out-of-zone.

The DSGEIS must assure the public that fractures can be contained to the Marcellus Shale zone. The DSGEIS does not provide data sufficient to meet this standard. The DSGEIS does not document the existence of 3D reservoir simulation models for NYS' Marcellus Shale, nor does NYSDEC require engineers to design fracture treatments using 3D models.

While Marcellus Shale development in Pennsylvania precedes development in NYS, data collected from the Pennsylvania wells is not applicable to the NYS Marcellus Shale because the depth of burial, thickness, organic content, permeability, and other reservoir properties in NYS differ. Industry experts warn that site-specific data is critical:

*"**By their nature, shales are extremely variable and regional differences in structure, mineralogy and other characteristics should always be considered in treatment design**…The wide geographic range [of the Marcellus Shale] has led to numerous different completion schemes being utilized as with the geographic variation comes geologic variability within the formation itself. A primary topic of [industry] discussion has been determining the optimal size and type of stimulation treatment for a given area"* [119] *[emphasis added].*

Marcellus Shale thickness lessens substantially in western NYS to less than 75' for roughly one-third of the total anticipated development area.[120] HVHF treatments in thin shale zones increases the risk of fracturing out-of-zone, unless a very cautious approach is taken by tailoring the design to the geophysical properties of the shale, taking into account shale thickness, local stress conditions, compressibility, and rigidity.

NYSDEC's consultants point out that a gas operator has no incentive to fracture out of the Marcellus Shale zone, because doing so could result in a loss of gas reserves or an increase in produced water volumes. Yet, NYSDEC's consultant, ICF, also recognizes that fracture design is complicated and it is possible to inadvertently fracture out-of-zone. ICF examined the potential for fracture fluids to propagate vertically and contaminate overlying drinking water aquifers. ICF recommended a 1,000' vertical offset be used.

HCLLC agrees that the use of vertical and horizontal offsets (buffer zones) is a prudent approach. The next step is to determine the size of the offsets. Initially, in new areas, offsets should be large, and then may decrease over time, as field data is obtained and predictive capability is refined.

[119] Fontaine, J., Johnson, N., and Schoen, D., Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History, Society of Petroleum Engineers Paper 117772, October 2008.

[120] 2009 NYSDEC, DSGEIS, Figure 4.9.

In 2009, HCLLC pointed out that the 1,000' vertical offset proposed by ICF is not technically supported, and a horizontal buffer zone is also needed. HCLLC recommended that vertical and horizontal offsets be based on actual field data, 3D reservoir simulation modeling, and a peer-reviewed hydrological assessment. HCLLC recommended these steps be taken to ensure aquifers are protected and nearby wellbore intersections are avoided.

The 2011 RDSGEIS still does not provide technical justification for the proposed minimum 1,000' vertical offset, nor does it make a recommendation for a horizontal offset from existing wells.

Instead, the 2011 RDSGEIS provides data that shows HVHF treatments in the Marcellus Shale have propagated vertical fractures up to 1500' in length, and horizontal fractures can extend hundreds to thousands of feet, as further explained below. These data do not support the proposed buffers.

The 2011 RDSGEIS: The 2011 RDSGEIS agrees that in new areas hydraulic fracture model development and design is important, citing recommendations from the Ground Water Protection Council and its consultant ICF; yet, incongruously the RDSGEIS concludes it is unnecessary for operators to be required do this work in NYS (as a SGEIS mitigation measure or a NYCRR requirement).

> *Service companies design hydraulic fracturing procedures based on the rock properties of the prospective hydrocarbon reservoir. For any given area and formation, hydraulic fracturing design is an iterative process, i.e., it is continually improved and refined as development progresses and more data is collected.* ***In a new area, it may begin with computer modeling to simulate various fracturing designs and their effect on the height, length and orientation of the induced fractures. After the procedure is actually performed, the data gathered can be used to optimize future treatments. Data to define the extent and orientation of fracturing may be gathered during fracturing treatments by use of microseismic fracture mapping, tilt measurements, tracers, or proppant tagging. ICF International, under contract to NYSERDA*** *to provide research assistance for this document,* ***observed that fracture monitoring by these methods*** *is not regularly used because of cost, but* ***is commonly reserved for evaluating new techniques, determining the effectiveness of fracturing in newly developed areas, or calibrating hydraulic fracturing models*** *[emphasis added].*[121]

NYSDEC's consultants (Alpha Geoscience and ICF), the Ground Water Protection Council, HCLLC, and industry all agree:

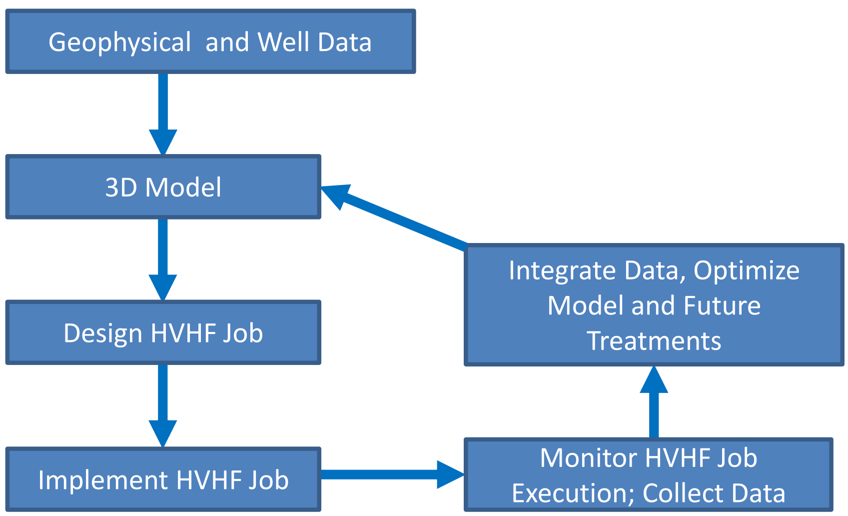
- There is a need for computer modeling on new gas shale play areas to simulate various fracturing designs and their effects on the height, length, and orientation of the induced fractures;
- After the HVHF treatment is actually performed, gathered data should be used to optimize future treatments; and
- There is technology available to further refine treatment design, including microseismic fracture mapping, tilt measurements, tracers, and proppant tagging.

However, these points of agreement are not reflected in the RDSGEIS, permit conditions, or NYCRR revisions. Remarkably, the 2011 RDSGEIS only has a few paragraphs in the entire 1,537 page document that discuss the importance of HVHF modeling and post-fracture assessment work (Chapter 5.8), and these recommendations are later disregarded in Chapter 7 proposed mitigation.

[121] 2011 NYSDEC, RDSGEIS, Page 5-88.

The use of 3D reservoir simulation to more accurately predict vertical and horizontal fracture growth is not new; reservoir simulation models have been used by petroleum engineers for decades. However, computational efficiency and model design have improved considerably, and more sophisticated simulation techniques are now available for shale gas reservoirs.

The basic engineering approach for populating a 3D reservoir simulation model is shown in the simplified flow diagram below, with geophysical data (seismic, well logs, core, samples, etc.) and existing nearby well data serving as the starting point. Once a model is built, it is used to design and optimize a safe and effective HVHF job. Data are gathered while the job is implemented, and those data are used to refine the model and improve future HVHF treatments.



There is abundant industry literature explaining the need for hydraulic fracture modeling and microseismic mapping, especially for new shale play developments, such as in NYS.

NYSDEC should recognize that the use of refined, site-specific models to optimize HVHF jobs is industry best practice. Quality operators with high standards routinely do this work. It should not be considered a burdensome practice, but rather a necessary requirement to protect groundwater and the environment.

Furthermore, it is economically attractive for an operator to use HVHF modeling. Models aid industry in making informed decisions, and prevents fracturing out-of-zone, which maximizes gas recovery rates.

Microseismic mapping has become a key tool for better understanding shale gas heterogeneities, identifying reservoir faults, and measuring actual fracture propagation orientation and length.

A 2010 industry paper[122] written by Rex Energy Corporation and MicroSeismic Inc. explains the importance of microseismic mapping for shale gas engineering:

> *By using microseismic source locations and mechanisms in conjunction with other geological and geophysical knowledge of an area, engineering and completion methods can be quickly corrected and enhanced. Induced fracture height, length, and placement influence the location, orientation and spacing of subsequent wells.* ***Microseismic monitoring allows for identification and characterization of unknown faults which intersect the wellbore and may significantly affect reservoir production and stimulations****. Formations with limited exploration with limited exploration data, such as the Marcellus shale, are ideal candidates for microseismic monitoring [emphasis added].*
>
> *In this case study, we will show how the* ***microseismic monitoring of a hydraulic fracture treatment in the Marcellus Shale identified a pre-existing natural fault which intersected the wellbore*** *[emphasis added].*

A 2011 industry paper[123] written by Marquette Exploration (a Marcellus Shale operator) and Schlumberger (an industry contractor), titled "Integrating All Available Data to Improve Production in the Marcellus Shale," emphasizes the importance of HVHF design and monitoring:

> *The operator featured in this paper is a small independent with Marcellus Shale areas of operation spanning across Belmont and Jefferson counties, eastern Ohio (Fig.2). This paper describes the methodology used by the operator to systematically gather the critical data during a pilot program to enhance the knowledge of their reservoir and develop optimized completion strategies and stimulation designs, thereby maximizing the true economic value of their asset.*
>
> *To build realistic property models, input from team members from different disciplines is required; in this study, team members included a geophysicist, geologist, petrophysicist, and reservoir engineer. Once the 3D structural model was completed, individual log measurements and interpreted properties from petrophysical, geomechanical, and image logs were incorporated in the model.*

Marquette Exploration's paper concludes:

- *Delineating a reservoir early on in the play and gathering as much data as possible can improve the drilling and completion design of the initial horizontal wells in the field to reduce the time and cost for an operator to get up the learning curve.*
- *Using all available data can greatly enhance the understanding in a field which, in turn, can improve the lateral design. Core data are imperative to calibrate petrophysical and geomechanical logs to further refine log models in other wells in an area.*
- *Seismic data in conjunction with strategically placed vertical logs can be used to construct a detailed static 3D geological model.*

[122] Hulsey, B.J., and Cornette, B. (MicroSeismic Inc.), and Pratt, D. (Rex Energy Corporation), Surface Microseismic Mapping Reveals Details of the Marcellus Shale, Society of Petroleum Engineers, SPE Paper 138806, 2010, Page 1.

[123] Ejofodomi, E., Baihly, J., Malpani, R., Altman, R, (Schlumberger), and Huchton, T., Welch, D., and Zieche, J., (Marquette Exploration), Integrating All Available Data to Improve Production in the Marcellus Shale, Society of Petroleum Engineers Paper, SPE 144321, 2011.

- *The thickness, depth, and continuity for shale sub-layers can vary greatly over a small area, so a pilot hole can be imperative to calibrate the geologic model for lateral landing point determination.*
- *The geologic model showed that the reservoir properties varied across the area of interest.*
- *Stochastic modeling can be used to successfully propagate interpreted log properties from a few wells across a large acreage.*
- *A novel reservoir modeling technique, Microseismic Fracture Network (MFN), was developed using microseismic data to properly describe the created complex fracture network.*

A 2010 industry paper[124] written by El Paso Exploration and Production and StrataGen Engineering stresses the importance of HVHF design:

> *…a primary conclusion is that as reservoir permeability decreases, proper well type selection and **effective hydraulic fracture stimulation design become much more crucial** [emphasis added].*
>
> ***Additional modeling with specifics must be performed to evaluate well type, fracture design, and spacing requirement for a specific well or formation** [emphasis added].*

A 2011 industry paper[125] written by Schlumberger also stresses the importance of HVHF design and monitoring:

> *The completion strategy and hydraulic fracture stimulation are the keys to economic success in unconventional reservoirs. **Therefore, reservoir engineering workflows in unconventional reservoirs need to focus on completion and stimulation optimization** as much as they do well placement and spacing. **This well-level focus requires the integration of hydraulic fracture modeling software and the ability to utilize measurements specific to unconventional reservoirs** [emphasis added].*
>
> ***It is very important to properly model hydraulic fracture propagation and hydrocarbon production mechanisms in unconventional reservoirs**, a significant departure from conventional reservoir simulation workflows. **Seismic-to-simulation workflows in unconventional reservoirs require hydraulic fracture models that properly simulate complex fracture propagation** which is common in many unconventional reservoirs, algorithms to automatically develop discrete reservoir simulation grids to rigorously model the hydrocarbon production from complex hydraulic fractures, and the ability to efficiently integrate microseismic measurements with geological and geophysical data. **The introduction of complex hydraulic fracture propagation models now allows these workflows to be implemented** [emphasis added].*

A 2010 industry paper[126] written by StrataGen Engineering and CMG (industry consultants) again highlights the importance of HVHF design and monitoring:

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[124] Shelley, R.F., Lolon, E., and Dzubin, B. (StrataGen Engineering), and Vennes, M. (El Paso Exploration and Production), Quantifying the Effects of Well Type and Hydraulic Fracture Selection on Recovery for Various Reservoir Permeability Using a Numerical Reservoir Simulator, Society of Petroleum Engineers Paper, SPE 133985, 2010, Pages 1 and 12.

[125] Cipolla, C.L., Fitzpatrick, T., Williams, M.J., and Ganguly, U.K., (Schlumberger), Seismic-to-Simulation for Unconventional Reservoir Development, Society of Petroleum Engineers Paper, SPE 146876, 2011, Page 1.

> *The widespread application of microseismic mapping has significantly improved our understanding of hydraulic fracture growth in unconventional gas reservoirs (primarily shale) and led to better stimulation designs. However, the overall effectiveness of stimulation treatments is difficult to determine from microseismic mapping, as the location of proppant and distribution of conductivity in the fracture network cannot be measured (and are critical parameters that control well performance). Therefore* ***it is important to develop reservoir modeling approaches that properly characterize fluid flow in and the properties of a complex fracture network, tight matrix, and primary hydraulic fracture (if present) to evaluate well performance and understand critical parameters that affect gas recovery*** *[emphasis added].*
>
> *Given the complex nature of hydraulic fracture growth and the very low permeability of the matrix rock in many shale-gas reservoirs combined with the predominance of horizontal completions,* ***reservoir simulation is commonly the preferred method to predict and evaluate well performance*** *[emphasis added].*
>
> *The most rigorous method to model shale-gas reservoirs is to discretely grid the entire reservoir, including the network fractures, hydraulic fracture, matrix blocks, and un-stimulated areas – but this increases computational time. However, with the continual advances in computing power, much more complex numerical models can be efficiently utilized.*

In 2010, Atlas Energy Resources published a Society of Petroleum Engineering Paper that explained the importance of reservoir characterization, modeling, the use of minifracs, and the use of microseismic data. Atlas Energy Resources explained that the use of advanced technology is good business:

> *This paper describes a procedure to enhance production in the Marcellus shale while optimizing economics through integration of minifrac, fracture treatment, microseismic, and production data technologies.*
>
> *Application of this integrated technology approach will help prodvide the operator with a systematic approach for designing, analyzing, and optimizing multi-stage/multi-cluster transverse hydraulic fractures in horizontal wellbores.*[127]

An engineering analysis and modeling prior to a HVHF treatment provides industry, regulators, and the public with confidence that the treatment has been thoroughly evaluated and designed to protect the environment. It is not sufficient for industry and NYSDEC to say this work is being done, while being unwilling to require it. If this work is being done, then creating a formal requirement in the SGEIS and NYCRR does not impose an incremental burden on the operator. Resistance to a formal requirement should signal to NYSDEC that industry best practice is not always followed.

While industry literature explains the need for hydraulic fracture modeling, this does not guarantee it will actually be implemented by all shale gas operators in NYS. Shale gas drilling has attracted numerous small, less experienced operators. Computational modeling requires personnel with expertise in building models, running them, and refining datasets. If the operator does not have sufficient in-house engineering and geophysical expertise, it should be required to hire experts to provide the necessary expertise.

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[126] Cipolla, C.L., Lolon, E.P. (StrataGen Engineering), Erdle, J.C., and Rubin, B. (CMG), Reservoir Modeling in Shale-Gas Reservoirs, Society of Petroleum Engineers Paper, SPE 125530, 2009, Pages 1,3, and 4.

[127] Henry Jacot, R. (Atlas Energy Resources), Bazan, L.W. (Bazan Consulting, Inc.), Meyer, B.R. (Meyer & Associates Inc.), Technology Integration – A Methodology to Enhance Production and Maximize Economics in Horizontal Marcellus Shale Wells, Society of Petroleum Engineers Paper, SPE 135262, 2010, Page 1.

Recommendation No. 32: Best practices for HVHF design and monitoring should be included in the SGEIS as a mitigation measure, and codified in NYCRR as a minimum standard.

Additionally, Alpha Geoscience, ICF, Ground Water Protection Council, HCLLC, and industry all agree that additional technical work is needed to develop new shale gas play areas; yet the 2011 RDSGEIS does not require the operator to develop or maintain a hydraulic fracture model. Instead, the 2011 RDSGEIS only requires the operator to abide by a 1000' vertical offset from protected aquifers and collect data during the HVHF job to evaluate whether the job was implemented as planned.[128]

Knowing whether a job was implemented as planned is only helpful if the initial design is protective of human health and environment. If the job is poorly planned, and is implemented as planned, that only proves that a poor job was actually implemented. This approach would not be in NYS' best interest.

Instead, NYS needs to first verify that the operator has engineered a HVHF treatment that is protective of human health and environment, and then, second, verify that the job was implemented to that protective standard. A rigorous engineering analysis is a critical design step. Proper design and monitoring of HVHF jobs is not only best practice from an environmental and human health perspective, it is also good business because it optimizes gas production and reduces hydraulic fracture treatment costs.

The 2011 RDSGEIS does not require a HVHF design plan.[129] The RDSGEIS does not require the operator to:

(a) Estimate the vertical and horizontal fracture length;

(b) Verify that the proposed HVHF design will not intersect protected groundwater or nearby wells;

(c) Use a site-specific hydraulic fracture model, based on NYS specific shale characteristics and the operational design parameters of the planned HVHF job (volume, pressure, rate, etc.).

Recommendation No. 33: The SGEIS and NYCRR should require the operator to:

(a) Estimate the maximum vertical and horizontal fracture propagation length for each well, and submit technical information (e.g. model output) with its application to support its computations.

(b) Describe in its post-well completion report whether the predicted vertical and horizontal fracture propagation lengths were accurate, or note discrepancies.

(c) Certify that the actual HVHF job was implemented safely, and fracture propagations did not intersect protected aquifers or nearby wells.

Additionally, NYS should reserve the right, and provide funding, to periodically review industry's models and computations to assess quality and verify this work is being completed.

[128] 2011 NYSDEC, RDSGEIS, Page 5-88.

[129] The operator is only required to verify that the vertical offset of 1000' is achieved and the shale is at least 2000' deep.

The 2011 RDSGEIS assumes that any HVHF job, no matter the volume, no matter the pressure, and no matter the shale thickness, will be safe, as long as it is conducted at a depth below 2,000'. The 2011 RDSGEIS recommends that site-specific SEQRA reviews be limited to wells shallower than 2000' and within 1000' of a protected aquifer.[130] The RDSGEIS lacks technical and scientific data to support the hypothesis that all HVHF treatments, regardless of design, at 2000' or deeper will be safe. Additionally, the RDSGEIS does not address safe horizontal fracture length.

NYSDEC does not provide data on HVHF treatments conducted between 2000' and 5000' deep; yet, NYS proposed to allow shale gas drilling at these depths. Instead, the RDSGEIS relies on limited data collected from Marcellus Shale fractures conducted in other states at depths below 5000'. However, even industry points out that data collected in one part of the Marcellus Shale cannot be applied to the entire shale.

For example, Guardian Exploration and Universal Well Services reports that optimal Marcellus Shale HVHF treatments are still being developed, and that a "one-size-fits-all approach should not be expected. They anticipate that industry will examine the use of higher rates and increased fluid volume and proppant mass in the future resulting in varied fracture lengths from current HVHF jobs:

> ***<u>Much work remains to be done in determining the optimal stimulation treatment for the Marcellus shale</u>***. ***<u>Certainly given the extremely large geographic area encompassed by the Marcellus play, it should not be expected that one size will fit all.</u>*** *While the treatment discussed here has been considered successful,* ***<u>future projects will examine the effects of increased rate, increased volumes in terms of both overall fluid volume and proppant mass, the effects of varying the proppant mesh ratios and concentrations, and optimization of flowback/cleanup rates</u>***. *The utilization of evaluation tools such as microseismic monitoring of fracture growth and horizontal drilling and completions to enhance reservoir development should also prove to be beneficial [emphasis added].*[131]

As HVHF treatment methods continue to evolve, NYSDEC must either set a limit in the SGEIS and NYCRR for the upper bounds of a safe HVHF job, or it must have a process in place for industry to provide site-specific engineering to support each well application to ensure that new HVHF designs are safe.

NYSDEC assumes that 1000' vertical separation between the bottom of the protected groundwater zone and the top of the shale zone where HVHF will occur is sufficiently protective, regardless of shale thickness, HVHF job size, and other subsurface characteristics. However, this approach is not technically supported. The 2011 RDSGEIS concludes:

> *As explained in Section 6.1.5.2, the conclusion that* ***<u>harm from fracturing fluid migration up from the horizontal wellbore is not reasonably anticipated is contingent upon the presence of certain natural conditions, including 1,000 feet of vertical separation between the bottom of a potential aquifer and the top of the target fracture zone.</u>*** *The presence of 1,000 feet of low-permeability rocks between the fracture zone and a drinking water source serves as a natural or inherent mitigation measure that protects against groundwater contamination from hydraulic fracturing [emphasis added].*[132]

[130] 2011 NYSDEC, RDSGEIS, Page 7-59.

[131] Fontaine, J., and Johnson, N. (Universal Well Services), and Schoen, D. (Guardian Exploration), Design, Execution, and Evaluation of a "Typical" Marcellus Shale Slickwater Stimulation: A Case History, Society of Petroleum Engineers Paper, SPE 117772, 2008, Page 11.

[132] 2011 NYSDEC, RDSGEIS, Page 7-59.

Neither the 2009 DSGEIS nor the 2011 RDSGEIS contain site-specific NYS Marcellus Shale hydraulic fracture model data to support NYSDEC's conclusion that a 1,000' vertical separation will be protective in all cases in NYS, especially where thinner, shallower shales are present. Furthermore, the 2011 RDSGEIS lacks data on vertical and horizontal fracture propagation in the Marcellus Shale at depths between 2000' and 5000' (depths that NYS proposes to permit).

The behavior of HVHF propagation in NYS is not currently well understood. HCLLC was unable to locate any NYS site-specific hydraulic fracture models for the Marcellus, Utica, or other low-permeability reservoirs. If these models exist, they should be described in the SGEIS, and NYSDEC should explain how it used the data from these models to inform its SGEIS.

Instead, the RDSGEIS currently relies on Marcellus Shale HVHF data from other states that may not be applicable to NYS. For example, NYSDEC points to data collected on 400 Marcellus hydraulic fractures conducted in Pennsylvania, West Virginia, and Ohio. This data was summarized in a three page article in the American Oil & Gas Reporter in July 2010:

> *Four hundred Marcellus hydraulic fracturing stages in Pennsylvania, West Virginia and Ohio have been mapped with respect to vertical growth and distance to the deepest water wells in the corresponding areas. Although many of the hydraulic fracturing stages occurred at depths greater than the depths at which the Marcellus occurs in New York, the results across all depth ranges showed that induced fractures did not approach the depth of drinking water aquifers. In addition, as previously discussed, at the shallow end of the target depth range in New York, fracture growth orientation would change from vertical to horizontal.*[133]

NYSDEC's conclusions rely heavily on the American Oil & Gas Reporter three-page article (Fisher, 2010); yet NYSDEC does not further investigate the origin of the data contained in this article or its implications for shale development in NYS. Fracture growth is a function of type of formations located above and below the Marcellus Shale. Subsurface geology will vary across states and the RDSGEIS does not explain how this data is applicable to NYS. For example, this article:

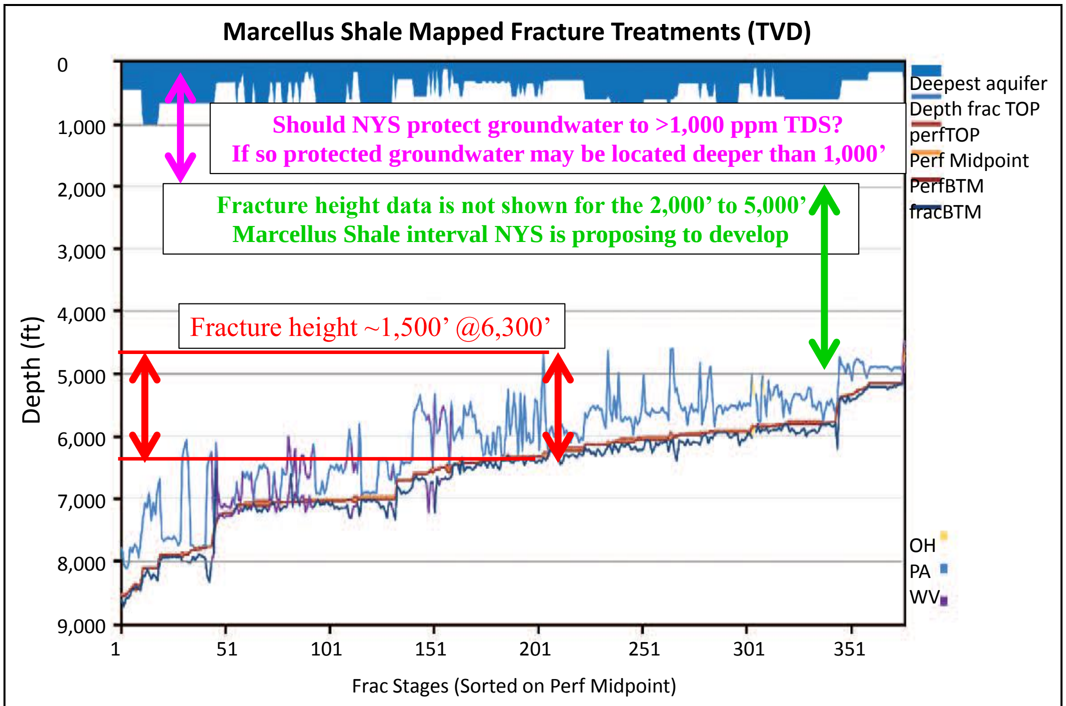
- Does not provide any information on the maximum HVHF job size (volumes, pressures, rates, etc.) to verify whether the fracture treatments conducted and analyzed are equivalent to the maximum HVHF job size anticipated in NYS;
- Does not provide any information on the Marcellus Shale thickness or geophysical properties present during the HVHF treatments;
- Shows that vertical fractures in excess of 1000' were observed (the plot, which is copied from the Fisher 2010 report and provided below, shows a 1500' vertical fracture propagated at 6300');
- Does not show what the vertical fracture growth height would be in the 2000-5000' Marcellus Shale depth interval that NYS proposes to develop; and,
- Does not show the horizontal distance that a fracture will propagate at the shallower shale depths NYS plans to develop.

[133] 2011 NYSDEC, RDSGEIS, Page 6-56.

A more in-depth technical paper written by Kevin Fisher (Halliburton) in 2011 appears to be the origin of the data cited in the American Oil & Gas Reporter article. Fisher's 2011 paper[134] concludes that:

> ***Fracture lengths can sometimes exceed a thousand feet*** *when contained with a relatively homogeneous layer [emphasis added].*
>
> ***At depths deeper than about 2,000 ft****, the vertical stress or overburden is generally the largest single stress so* ***the principal fracture orientation is expected to be vertical*** *on deeper wells [emphasis added].*
>
> ***At some point on shallow wells, the overburden stress will decrease to a point where it is less than the maximum horizontal stress and, at this point, one would expect the fracture growth to be horizontal and not vertical.*** *As wells get shallower, and the overburden stress lessens, mapped fractures are typically observed exhibiting increasingly larger horizontal components.* ***All of the fractures do not necessarily turn horizontal; they might have significant vertical and horizontal components with more of a T-shaped geometry,*** *but the horizontal components can become significant and could thieve away enough fluid causing a blunting effect, limiting upward fracture-height growth [emphasis added].*

The Marcellus fracture height figure shown in the American Oil & Gas Reporter is provided below; HCLLC annotated it to identify additional evaluation that is needed for NYS.



Plot from Fisher 2010 Cited in 2011 rdSGEIS; annotated by HCLLC with additional red, green, and magenta font information.

The use of vertical offset limits to separate hydrocarbon recovery operations from protected aquifers is a reasonable approach, but it must be scientifically and technical supported. While it is possible that a 1,000' vertical offset may potentially be sufficiently protective; the 2011 RDSGEIS does not provide sufficient scientific data or technical examination to support this recommended threshold.

[134] Fisher, K. and Warpinski, N., Pinnacle- A Halliburton Service, Hydraulic Fracture-Height Growth: Real Data, Society of Petroleum Engineers Paper, SPE 145949, 2011, Pages 1-2 and 5.

In addition to understanding the maximum vertical fracture propagation height, horizontal fracture propagation distance is an important consideration, especially when developing shallower shale zones. Fractures in shallower formations will tend to propagate on the horizontal plane. HVHF treatments should be designed to prevent fractures from intersecting with existing improperly constructed and improperly abandoned wells, and transmissive faults and fractures, which can provide pollutants a direct pathway to protected groundwater resources.

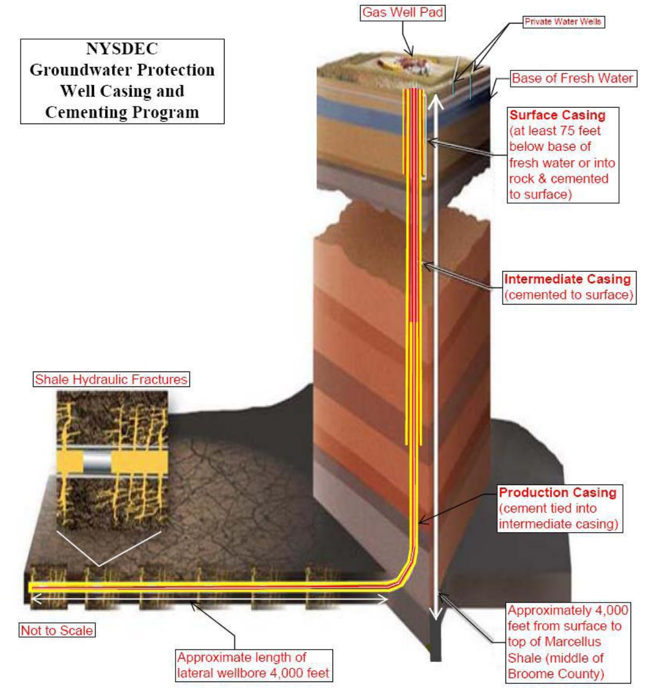
For example, in 2010 the BC Oil & Gas Commission issued a safety advisory on the risks of fracture treatments intersecting adjacent wells. The advisory specifically notified industry that:

> *A large kick was recently taken on a well being horizontally drilled for unconventional gas production in the Montney formation***. The kick was caused by a fracturing operation being conducted on an adjacent horizontal well. Fracture sand was circulated from the drilling wellbore, which was 670m [~2200'] from the wellbore undergoing the fracturing operation.** *[emphasis added].*[135]

Additionally, the advisory reported 18 known fracture communication incidents in B.C. and one in Western Alberta: five incidents of fracture stimulation communicating with an adjacent well; three incidents of drilling into a hydraulic fracture formed during a previous stimulation on an adjacent well and containing high pressure fluids; 10 incidents of fracture stimulations communicating into adjacent producing wells, and one incident of fracture stimulations communication into an adjacent leg on the same well for a multi-lateral well. Therefore fracture stimulations communication with adjacent wells is a known and reasonably foreseeable risk.

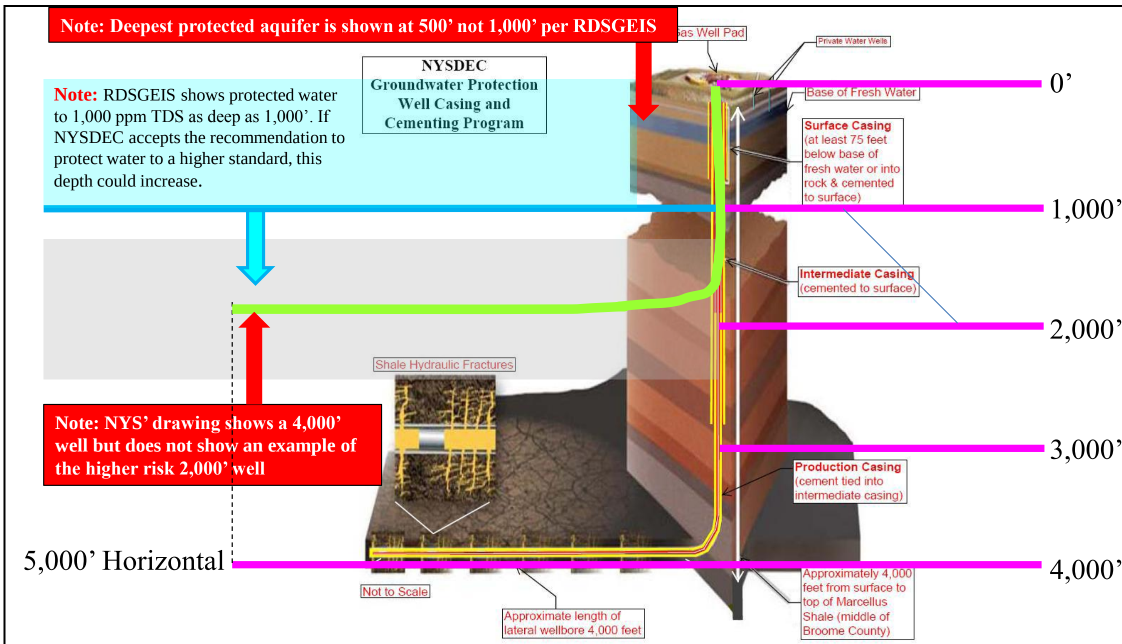
The 2011 RDSGEIS includes a wellbore schematic used in presentations given by the NYSDEC Commissioner. This wellbore schematic, shown below, depicts an example Marcellus Shale well. In the example the base of freshwater is at 500', the well is drilled to a depth of 4,000', and the horizontal length of the well is 4,000'.

[135] BC Oil & Gas Commission, Safety Advisory 2010-03, Communication During Fracture Stimulation, May 20, 2010.



Drawing from: Presentation by Commissioner Joe Martens NYS Department of Environmental Conservation, 2011 Supplemental Generic Environmental Impact Statement for High-Volume Hydraulic Fracturing showing a 500' freshwater depth and a 4,000' HVHF well.

The drawing does not represent the highest risk wells proposed in the 2011 RDSGEIS. The highest risk wells allowed under the 2011 RDSGEIS would be drilled into a thin section of the Marcellus Shale at a 2,000' depth, with protected water located above at 1,000'. Below is an annotated version of this wellbore schematic, prepared by HCLLC, showing the higher risk wells proposed under the RDSGEIS.



Drawing from: Presentation by Commissioner Joe Martens NYS Department of Environmental Conservation, 2011 Supplemental Generic Environmental Impact Statement for High-Volume Hydraulic Fracturing was annotated by HCLLC to show a HVHF well constructed at 2,000' depth, the base of freshwater at least at 1,000' and a theoretical uncertainty zone associated with vertical and horizontal fracture propagation at 2,000' depth.

As explained in Chapter 9 of this report , if a HVHF treatment intersects with a nearby improperly abandoned well, the potential exists for the improperly abandoned well to become a vertical conduit, and therefore transfer hydraulic fluid and mobilized gas to protected aquifers. Additionally, the pollution risk posed by possible HVHF intersections is not limited to improperly abandoned wells; existing wells that were poorly designed and constructed could also pose a risk.

Physics dictate that fractures form perpendicular to the direction of the least amount of stress. Vertical fracture height will decrease with depth, and horizontal fracture length will increase.

NYSDEC proposes that operators identify wells within a mile radius around the surface location of a HVHF well, to identify wells that might be at risk of intersection with HVHF treatments.[136] However, NYSDEC does not provide technical data to support a mile radius. The 2011 RDSGEIS does not specify a maximum horizontal drilling length. Although NYSDEC's spacing rules may impose some limitation on this length, limitations are not clearly explained in the RDSGEIS.

The RDSGEIS should identify the maximum horizontal fracture propagation distance that could occur in a shallow well to ensure that HVHF treatments do not intersect existing wellbores. This should be included in the SGEIS. Limits on horizontal drilling section lengths and HVHF job size, including a safety zone around each HVHF well, should also be established.

Recommendation No. 34: The SGEIS should provide a basis for the maximum horizontal well drilling limit. The SGEIS should also explain how the operator will verify that the maximum horizontal well drilling limit, plus the maximum predicted horizontal fracture length, will avoid nearby well intersection.

The most logical way forward is to begin by limiting development to the deepest Marcellus Shale intervals, maximizing the vertical separation from drinking water aquifers. Once accurate, field-calibrated 3D reservoir simulation models are available for NYS, development can then move to shallower intervals, as long as technical data shows that treatments will remain in zone.

Recommendation No. 35: The SGEIS should technically justify vertical and horizontal HVHF treatment offsets. Proposed offsets should be supported by hydraulic fracture modeling. Modeling should reflect the maximum HVHF job designs allowed in NYS and shale reservoir characteristics. NYSDEC should provide public access to the scientific data and hydraulic fracture models it uses to develop vertical and horizontal offsets for the purposes of the SGEIS.

Drilling into the deepest, thickest Marcellus Shale intervals (e.g., below 4000') will maximize data collection, affording access to all overlying intervals. Core samples, well logs, and pressure transient data can be obtained, verifying whether there are continuous permeability barriers hydraulically separating the Marcellus Shale and the overlying drinking water aquifers, and geologic barriers that will limit fracture propagation. Initially, smaller fracture treatments should be used as tests. These treatments can be increased in size over time, if data support the conclusion that large fracture treatments can remain in zone. As data are collected, and 3D reservoir models are developed and refined, it may be possible to safely develop the Marcellus at shallower depths and in thinner intervals.

NYSDEC's recommendation to move forward with shale gas development, absent additional engineering data and hydraulic fracture models, is technically unsupported and in direct conflict with the information cited in its 2009 DSGEIS and 2011 RDSGEIS, as well as its own consultants' recommendations.

[136] 2011 NYSDEC, RDSGEIS, Page 6-56.

Recommendation No. 36: The SGEIS should include a more thorough examination of hydraulic fracture modeling. The SGEIS and NYCRR should require the operator to:

(a) Collect additional geophysical and reservoir data to support a reservoir simulation model;

(b) Develop a high-quality Marcellus Shale 3D reservoir model(s) to safely design fracture treatments;

(c) Maintain and run hydraulic fracture modeling prior to each fracture treatment to ensure that the fracture is contained in zone;

(d) Collect and carefully analyze data from HVHF treatments to optimize future HVHF treatments;

(e) Initially complete HVHF treatments in the deepest, thickest sections of the Marcellus Shale to gain data and experience before proceeding to shallower zones (e.g. 4000' deep and 150' thick, progressively moving shallower as more NYS site-specific information is collected); and

(f) Conduct post-fracture analysis, and provide that analysis to NYS to demonstrate that the HVHF treatment was safely implemented.

NYCRR Proposed Revisions: There are no proposed revisions in the NYCRR. As proposed, the NYCRR do not require operators to:

(a) Submit a HVHF designs to NYS;

(b) Estimate the vertical and horizontal fracture length;

(c) Provide engineering analysis and run HVHF modeling;

(d) Monitor HVHF performance to ensure that HVHF design and actual implementation in the field match; and

(e) Notify NYSDEC if the actual vertical and/or horizontal fracture length greatly exceeds the job design, such that risk may be present to the environment.

11. Hydraulic Fracture Treatment Additive Limitations

Background: In 2009, HCLLC recommended that NYS regulations identify fracture treatment additives that are protective of human health and the environment. HCLLC also recommended that the NYCRR include a list of prohibited chemical additives.

2011 RDSGEIS: The 2011 RDSGEIS includes improvements in the handling and storage of HVHF chemicals by requiring chemicals to be stored in suitable containers placed in secondary containment. Additionally, NYSDEC encourages operators to select the lowest toxicity chemicals. However, neither the 2011 RDSGEIS nor the proposed NYCRR amendments establish a prohibited chemical list, nor do they **require** an operator to use the lowest toxicity chemicals. Instead, the 2011 RDSGEIS requires only that the operator evaluate alternative products. Ultimately, the operator is allowed to select the final chemicals used with no firm evaluation criteria listed in the NYCRR to rule out harmful chemicals.

NYCRR Proposed Revisions: Proposed regulations at 6 NYCRR § 560.3(c)(1)(v) require only that the operator provide:

> *Documentation that proposed chemical additives exhibit reduced aquatic toxicity and pose a lower potential risk to water resources and the environment than available alternatives; or documentation that available alternative products are not equally effective or feasible.*

The proposed regulation requires the operator to examine chemicals that "exhibit reduced aquatic toxicity" and a "lower risk to water resources," but the NYCRR does not provide specific criteria for determining what is an acceptable reduction in toxicity or an acceptable reduction in risk.

The 2011 RDSGEIS guides the operator to conduct a five-part analysis:

> *The evaluation criteria should include (1) impact to the environment caused by the additive product if it remains in the environment, (2) the toxicity and mobility of the available alternatives, (3) persistence in the environment, (4) effectiveness of the available alternative to achieve desired results in the engineered fluid system, and (5) feasibility of implementing the alternative.*[137]

However the 2011 RDSGEIS does not instruct the operator on what is required if any part of the five-part analysis has an unacceptable outcome, nor does the NYCRR. For example, if an operator proposes a chemical additive that is known to impact the environment and be persistent if it remains in the environment, but the operator proposes no other alternative, or states that this is the only chemical that will be effective for its planned job, neither the RDSGEIS or the NYCRR prohibit the operator from using this chemical even if it is harmful.

As proposed, the NYCRR would still allow the use of a highly toxic chemical, as long as it was slightly less toxic than the most toxic chemical available. This is not best practice. Best practice would be to use the chemical with the lowest impact and risk, not just a slightly improved risk. Best practice would also be for NYS to develop a list of prohibited chemicals that pose an unacceptable risk to human health and the environment.

[137] 2011 NYSDEC, RDSGEIS, Page 8-30.

The 2011 RDSGEIS concludes that it is not possible for hydraulic fracturing to contaminate groundwater, erroneously assuming that all wells will be flawlessly constructed and operated, and that no human error is possible that would put hydraulic fracturing additives in contact with groundwater, with the exception of a potential surface spill. The 2011 RDSGEIS concludes:

> *The regulatory discussion in Section 8.4 concludes that adequate well design prevents contact between fracturing fluids and fresh ground water sources, and text in Chapter 6 along with Appendix 11 on subsurface fluid mobility explain why ground water contamination by migration of fracturing fluid is not a reasonably foreseeable impact.*[138]

The 2011 RDSGEIS should be revised to clarify that groundwater contamination by hydraulic fracturing fluids is a reasonably foreseeable impact that requires mitigation. Well construction failures, engineering design flaws, human error, mechanical malfunctions, and chemical spills all are reasonably foreseeable events, and have occurred at Marcellus Shale operations in Pennsylvania.[139] Additionally, Dr. Myers identifies the potential long-term contaminant transport through conductive faults, natural fractures, and advective transport.[140]

Groundwater contamination has been attributed to operational failures at various Marcellus Shale gas development operations in Pennsylvania, including operations by Cabot Oil & Gas Corporation, Catalyst Energy, Inc., and Chesapeake Energy Corporation.

For example, on February 27, 2009, the Pennsylvania Department of Environmental Protection (PADEP) issued a Notice of Violation to Cabot Oil & Gas Corporation for unpermitted discharge of polluting substances and failure to prevent gas from entering fresh groundwater, among other deficiencies, in connection with its drilling activities in Dimock Township.[141] PADEP inspectors *"...discovered that the well casings on some of Cabot's natural gas wells were cemented improperly or insufficiently, allowing natural gas to migrate to groundwater...DEP ordered Cabot to cease hydro fracking natural gas wells throughout Susquehanna County*."[142] In April 2010, under its consent order and agreement with PADEP, Cabot was required to plug three leaking wells that contaminated the groundwater and drinking water supplies of 14 homes in the region.[143]

In 2011, PADEP issued a cease and desist order to Catalyst Energy, Inc. that prohibited the company from conducting drilling and hydraulic fracturing operations, after a PADEP investigation confirmed that private water supplies serving two homes had been contaminated by natural gas and elevated levels of iron and manganese from Catalyst's operations.[144]

In May 2011, PADEP fined Chesapeake Energy Corporation $1,088,000 for violations related to natural gas drilling activities that contaminated private water supplies in Bradford County. PADEP issued a news release reporting:

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[138] 2011 NYSDEC, RDSGEIS, Page 8-29.

[139] DEP Investigating Lycoming County Fracking Fluid Spill at XTO Energy Marcellus Well, November 22, 2010, available at http://www.portal. state.pa.us/portal/server.pt/community/newsroom/

14287?id=15315&typeid=1

[140] Dr. Tom Myers, Comments Prepared for NRDC on 2011 RDSGEIS, 2012.

[141] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[142] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=2418&typeid=1.

[143] http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=10586&typeid=1.

[144] DEP Orders Catalyst Energy to Stop Operations at Gas Wells in Forest County Village, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=16894&typeid=1.

> *DEP determined that because of improper well casing and cementing in shallow zones, natural gas from non-shale shallow gas formations had experienced localized migration into groundwater and contaminated 16 families' drinking water supplies.*[145]

If HVHF treatments are conducted in poorly constructed wells, there exists a potential for groundwater contamination. Therefore, as NYSDEC recommends, well construction must be robust, and the use of safe HVHF treatment additives provides any extra layer of protection in the event that human error or mechanical malfunction create a pathway for such additives to reach groundwater. Reducing the toxicity of hydraulic fracturing additives by listing prohibited additives mitigates the impact of both surface and groundwater pollution if it occurs.

Recommendation No. 37: NYSDEC should develop a list of prohibited fracture treatment additives based on the known list of chemicals currently used in hydraulic fracturing. The list of prohibited fracture treatment additives should apply to all hydraulic fracture treatments, not just HVHF treatments. NYSDEC should also develop a process to evaluate newly proposed hydraulic fracturing chemical additives to determine whether they should be added to the prohibited list. No chemical should be used until NYSDEC and/or the NYSDOH has assessed whether it is protective of human health and the environment, and has determined whether or not it warrants inclusion on the list of prohibited hydraulic fracturing chemical additives for NYS. The burden of proof should be on industry to demonstrate, via scientific and technical data and analysis, and risk assessment work, that the chemical is safe. Fracture treatment additive prohibitions should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

The 2009 DSGEIS Section 5.3[146] stated that NYSDEC collected compositional information from chemical suppliers and service companies on many of the additives proposed for use in shale fracture treatments. NYSDEC reported partial compositional data on 197 products and complete compositional data on 152 products. Tables 5.3-5.7 provided lists of chemicals proposed for use in fracture treatments, and Section 5.4.3.1 described the potential health impacts of categories of chemicals. Yet the 2009 DSGEIS did not arrive at any recommendation or conclusion about which fracture treatment additives are acceptable for use in NYS and which are not. This problem persists in the 2011 RDSGEIS.

Chapter 5 of the 2011 RDSGEIS explains that NYSDOH reviewed information on 322 unique chemicals present in 235 products proposed for hydraulic fracturing of shale formations in New York and categorized them into chemical classes, but did not develop any recommendations for prohibiting specific HF additives. The 2011 RDSGEIS merely concludes that the 322 unique chemicals studied did not identify any potential exposure situations that are qualitatively different from those addressed in the 1992 GEIS.[147] This conclusion has little significance, since the 1992 GEIS did not establish any criteria for limiting or prohibiting HF chemical additives (i.e., for mitigating potential significant adverse impacts from exposure to these additives). For example, Dr. Miller points out that acrylonitrile and acrylamide are listed, and known to be carcinogenic and quite toxic, but fairly short lived in an aqueous environment.[148] As proposed, NYSDEC would allow these carcinogenic, toxic chemicals to be used, unless industry proposes a less-harmful chemical. The appropriate step for NYS would be to add acrylonitrile and acrylamide, among other chemical that pose a risk to human health or the environment, to the list of prohibited chemicals in NYS.

[145] DEP Fines Chesapeake Energy More Than $1 Million, available at http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=17405&typeid=1.

[146] 2009 NYSDEC, DSGEIS, Page 5-34.

[147] 2011 NYSDEC, RDSGEIS, Page 8-29.

[148] Dr. Glenn Miller, Comments Prepared for NRDC on 2011 RDSGEIS, 2012.

Although the percentage of hydraulic fracturing fluid that is composed of chemicals may be small—typically 0.5 to 2 percent of the total volume required for a Marcellus Shale hydraulic fracture stimulation—the absolute volume of chemicals used is very large. A typical Marcellus Shale well may require the use of more than five million gallons of freshwater for drilling and hydraulic fracturing. A five million gallon hydraulic fracture treatment would require approximately 25,000 to 100,000 gallons of hydraulic fracturing chemicals per well at a chemical additive dosage of 0.5 to 2 percent. Some of these chemicals are toxic, including known or possible human carcinogens, chemicals regulated under the Safe Drinking Water Act due to their risks to human health, and chemicals regulated under the Clean Air Act as hazardous air pollutants.[149]

Recommendation No. 38: The SGEIS should do more than just list chemicals proposed by industry for HVHF operations and describe their toxicity; the SGEIS should identify chemicals that should be prohibited or used with limitations to protect human health and the environment.

Additionally, the 2011 RDSGEIS includes a process for reviewing chemicals proposed by industry that appears to have little value or scientific rigor.

> *For every well permit application the Department would require, as part of the EAF Addendum, identification of additive products, by product name and purpose/type, and proposed percent by weight of water, proppants and each additive. This would allow the Department to determine whether the proposed fracturing fluid is water-based and generally similar to the fluid represented by Figures 5.3, 5.4, and 5.5.*[150]

Figures 5.3, 5.4, and 5.5 in the 2011 RDSGEIS are merely pie charts showing example compositions from previous Fayetteville and Marcellus Shale HVHF jobs. The 2011 RDSGEIS does not include a scientific analysis of the proposed HVHF compositions to verify if these mixtures are optimal. Therefore, there is little scientific value in having NYSDEC staff compare an operator's proposed HVHF composition to these figures, because NYSDEC has not even completed the fundamental scientific analysis to verify whether these proposed treatment compositions are protective of human health and the environment and whether the figures are a suitable yardstick.

The 2011 RDSGEIS proposes to require industry to submit a Material Safety Data Sheet (MSDS) for every new product that is not currently listed by NYSDEC in Chapter 5 of the 2011 RDSGEIS. NYSDEC explains that the MSDS will provide it with more information on the proposed chemical, but does not institute a plan for taking action to limit or prohibit hazardous chemical use based on a review of that MSDS. Instead, the 2011 RDSGEIS appears to propose that NYSDEC will just collect MSDS information and take no action, other than to accept the chemicals selected by the operator and add the MSDS to NYSDEC's file system.

> *The Department would also require the submittal of an MSDS for every additive product proposed for use, unless the MSDS for a particular product is already on file as a result of the disclosure provided during the preparation process of this SGEIS (as discussed in Chapter 5) or during the application process for a previous well permit. Submittal of product MSDSs would provide the Department with the identities, properties and effects of the hazardous chemical constituents within each additive proposed for use.*[151]

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[149] United States House of Representatives, Committee on Energy and Commerce, Minority Staff, Chemicals Used in Hydraulic Fracturing, April 2011.

[150] 2011 NYSDEC, RDSGEIS, Page 8-30.

[151] 2011 NYSDEC, RDSGEIS, Page 8-30.

The 2011 RDSGEIS goes on to say that NYSDEC staff will verify, by reviewing the well completion form, that the chemicals proposed by industry in a permit application (with no limitations or prohibitions by NYSDEC) were actually the same chemicals used on the HVHF job.

> *In addition to the above requirements for well permit applications, the Department would continue its practice of requiring hydraulic fracturing information, including identification of materials and volumes of materials utilized, on the well completion report which is required, in accordance with 6 NYCRR §554.7, to be submitted to the Department within 30 days after the completion of any well. This requirement can be utilized by Department staff to verify that only those additive products proposed at the time of application, or subsequently proposed and approved prior to use, were utilized in a given high-volume hydraulic fracturing operation.*[152]

The proposed review process holds little scientific or audit value, since NYSDEC is not limiting chemicals in the initial application. It is insufficient to bind industry to use specific chemicals at the tail end of the permitting process, when industry can propose any chemical for use on the front-end.

However, the proposed chemical audit review process would have great value if NYSDEC limited or prohibited chemical use in the initial application. In that case, a post-HVHF review process would be valuable to verify that prohibited chemicals were not used.

There are several international models in place that NYSDEC could consider using to develop a prohibited chemical list, or to develop an approved list of chemical, or both. Below is a short summary of three models that could be considered: (1) the Oslo-Paris Convention (OSPAR) list of environmentally friendly chemicals (chemicals considered to Pose Little Or No Risk (PLONOR) for the oil and gas industry); (2) Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) Offshore Chemical Selection Guidelines for Drilling & Production Activities on Frontier Lands; and (3) the Norwegian Pollution Control Authority chemical coding system for the oil and gas industry. These governmental entities prohibit use of chemicals that have harmful characteristics, such as: low biodegradability; high bioaccumulation potential; high acute toxicity; and detrimental mutagenic or reproductive effects.

OSPAR PLONOR: Certain European governmental entities have developed a list of environmentally friendly chemicals. Under the Oslo-Paris Convention (OSPAR)[153] a list of chemicals that were considered to Pose Little Or No Risk (PLONOR) to the marine environment was developed for use in drilling and stimulation treatments. The PLONOR list was initially developed in early 2000 and has been amended several times to add and de-list chemicals. The PLONOR list has been very effective in reducing chemical pollution from offshore operations, and use of the PLONOR list has expanded to onshore oil and gas operations and to other industrial sectors. HCLCC is not recommending that NYS adopt the PLONOR list without review; instead, HCLLC is recommending that NYSDEC consider a process similar to OSPAR's system to develop a list of hydraulic fracturing treatment additives that would pose little or no risk to human health or the environment if the chemicals spilled, leaked, or were improperly disposed, or, in the alternative, consider developing a list of chemicals to be prohibited from use in hydraulic fracturing operations.

[152] 2011 NYSDEC, RDSGEIS, Page 8-31.

[153] The Convention for the Protection of the Marine Environment of the North-East Atlantic (the "OSPAR Convention") was opened for signature at the Ministerial Meeting of the former Oslo and Paris Commissions in Paris on 22 September 1992. The Convention entered into force on 25 March 1998. It has been ratified by Belgium, Denmark, Finland, France, Germany, Iceland, Ireland, Luxembourg, Netherlands, Norway, Portugal, Sweden, Switzerland and the United Kingdom and approved by the European Community and Spain.

The OSPAR process is straight forward: the establishment of criteria for inclusion of substances on the PLONOR list. Industry has the burden of proof to provide scientific and technical data to support listing of a chemical as PLONOR—i.e., industry must prove the chemical poses little or no risk. The OSPAR Commission reviews the data and makes the final listing determination. The Commission also can remove chemicals from the PLONOR list if new information comes to light warranting a de-listing. A current list of PLONOR chemicals can be found at the OSPAR website.[154]

C-NLOPB Guidelines: The Canada-Newfoundland and Labrador Offshore Petroleum Board has developed guidelines that industry must follow to select less harmful chemicals used in their offshore oil and gas operations.[155] Industry operators must demonstrate that they have incorporated a chemical selection process in their management system that conforms to the guidelines, and the Board has the ability to audit industry compliance. The guidelines are reviewed at least once every five years to ensure that gains in scientific and technical knowledge are incorporated, and more frequent reviews may be initiated if significant risks are identified. The C-NLOPB Guidelines rely in part on the PLONOR list, but also establish specific requirements for hazard and risk assessment.

The Norwegian Pollution Control Authority has developed a chemical coding system to prohibit use of harmful and toxic chemicals in the Norwegian petroleum industry. The Norwegian Pollution Control Authority system categorizes chemicals by color, using the colors: black, red, yellow and green. Black chemicals are the most hazardous, followed by red, then yellow. Green chemicals are those listed on the PLONOR list.

<u>Black:</u> chemicals on the OSPAR List of Chemicals for Priority Action, chemicals on the Norwegian Pollution Control Authority prioritized list (White Paper No. 21 (2004-2005)), and chemicals in the following categories, characterized by certain ecotoxicological properties:

- Substances that have both a low biodegradability (BOD_{28}<20%) and a high bioaccumulation potential (log P_{OW}•5);
- Substances that have both a low biodegradability (BOD_{28}<20%) and a high acute toxicity (EC_{50} or LC_{50}•10 mg/l); and
- Substances that are detrimental in a mutagenic or reproductive way.

<u>Red:</u> chemicals in the following categories, characterized by certain ecotoxicological properties:

- Inorganic substances that are acutely toxic (EC_{50} or LC_{50}•1 mg/l);
- Organic substances with a low biodegradability (BOD_{28}<20%);
- Substances that meet two of the three following criteria:
  - Biodegradability equivalent to BOD_{28}<60%;
  - Bioaccumulation potential equivalent to log P_{OW}•3 and molecular weight < 700; or
  - Acute toxicity of EC_{50} or LC_{50}•10 mg/l.[156]

[154] OSPAR Convention for the Protection of the Marine Environment of the North-East Atlantic, OSPAR List of Substances/Preparations Used and Discharged Offshore Which Are Considered to Pose Little or No Risk to the Environment (PLONOR), Reference Number: 2004-10, 2008 Update, available at: http://www.klif.no/arbeidsomr/petroleum/dokumenter/plonor2008.pdf

[155] The Canada-Newfoundland and Labrador Offshore Petroleum Board, Offshore Chemical Selection Guidelines for Drilling & Production Activities on Frontier Lands, April 2009, available at http://publications.gc.ca/collections/collection_2009/one-neb/NE23-151-2009E.pdf.

[156] Regulations Relating to Conduct of Activities in the Petroleum Activities (The Activities Regulations), § 56b. The latest update of this list can be found on OSPAR's website under the Offshore Oil and Gas Industry, Decisions, Recommendations and other Agreements.

Green: chemicals on the OSPAR PLONOR list (chemicals considered to Pose Little Or No Risk to the marine environment).

Yellow: chemicals that are not categorized as Green, Black or Red.

Recommendation No. 39: The SGEIS and the NYCRR should include a more rigorous technical and scientific review process to examine newly proposed fracture treatment additives to ensure they are protective of human health and the environment. In addition to a list of prohibited chemicals, NYSDEC should develop a list of recommended/approved fracture treatment additives that have been scientifically and technically reviewed by NYSDEC and NYSDOH and confirmed to pose little or no risk to human health or the environment. This list could be provided to industry for immediate use and would provide industry with a simplified list of chemicals that have already been determined to pose the least risk.

Any chemical not found on this list, or on the list of prohibited chemicals, could be proposed by industry for future use, but would be subject to an in-depth scientific and technical justification and risk assessment review process before being added to the approved chemical list for NYS.

No chemical should be used until NYSDEC and/or the NYSDOH has assessed whether it is protective of human health and the environment. Industry should bear the burden of proof of demonstrating to NYSDEC and NYSDOH that the chemical is safe. The technical and scientific review and approval process to examine newly proposed fracture treatment additives should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This more rigorous technical and scientific review process should apply to all hydraulic fracture treatments, not just HVHF treatments.

12. Drilling Mud Composition and Disposal

Background: In 2009, HCLLC recommended that the NYCRR be revised to: acknowledge and mitigate drilling mud pollution impacts; minimize drilling waste generation; limit heavy metal and NORM content; and establish best practices for the collection, treatment and disposal of drilling waste.

NYCRR Proposed Revisions: NYSDEC proactively responded to scientific and technical information provided through the public input process, revising the NYCRR to recognize that drilling muds are polluting fluids. NYSDEC removed the existing sentence at 6 NYCRR § 554.1(c)(1) that says "drilling muds are not considered to be polluting fluids." This is an important and positive change in the regulations.

However, additional work is still needed in the proposed amendments to the NYCRR to define what types of drilling muds should be used at various depths in constructing a well. NYCRR should also be amended to include best practices for how those drilling muds should be properly handled and disposed.

In January 2011, NYS consultant, Alpha Geoscience complimented HCLLC for its recommendations on drilling mud composition and disposal and agreed that additional mitigation was warranted. Alpha Geoscience wrote: [157]

> *Harvey Consulting has commented on the need for regulation revisions to specifically address drilling mud and drilling waste. The report states "New York State regulations should be revised to acknowledge and mitigate drilling mud pollution impacts, minimize drilling waste generation, limit heavy metal and NORM (Naturally Occurring Radioactive Material) content, and establish best practices for collection, treatment and disposal of drilling waste.*
>
> *Current NYS regulation 6 NYCRR §554.1(c)(1) states that drilling muds are not considered polluting fluids. The 1992 GEIS allows drill cuttings to be buried onsite, and the dSGEIS does not address the potential impact. Drilling muds commonly contain barite which contains mercury (1-10 ppm) (www.fossil.energy.gov) and may also contain cadmium. NYSDEC has not set limits on the heavy metal content of drilling mud, and New York State regulations do not address how to dispose of drill cuttings containing NORM.*
>
> *Harvey Consulting's recommended best management practice for most applications includes a combination of waste minimization, using low impact additives, collecting waste in a closed-loop system, pumping waste to a cuttings reinjection unit, and disposing the waste into a disposal well by deep well injection. Harvey Consulting suggests NYSDEC should thoroughly analyze each situation and location to develop the best site-specific best management practices.*
>
> *Harvey Consulting's comments concerning the composition and handling of drilling mud and drilling waste appear to have some merit. Per 6 NYCRR §554.1 (C)(1) drilling muds are not considered polluting fluids, however the presence of mercury and cadmium in barite composed drilling muds may be cause for concern given the quantity of drilling mud that would be required to drill each well.*

[157] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Pages 7-9.

> *NYSDEC regulations do not clearly define the treatment or disposal of drilling waste and any best management practices concerning their handling, and/or recycling are not clearly outlined in the dSGEIS as documented by Harvey Consulting. Section 5.13 of the dSGEIS covers waste disposal, however it is general in its scope and does not outline any best management practices concerning the recycling, treatment, or disposal of drilling waste.*
>
> *Harvey Consulting's review recommends that the dSGEIS include best management practices concerning the type and handling of drilling mud and the subsequent waste byproducts. It suggests that NYSDEC should determine which drilling fluid composition and disposal methods are best practices for various scenarios.* ***Alpha agrees that the proposed measures seem reasonable and would serve to protect the public, environment, and the drilling applicant*** *[emphasis added].*

2011 RDSGEIS: The 2011 RDSGEIS explains that drilling operators propose to drill through protected groundwater zones using compressed air or Water-Based Muds (WBM).

> *The vertical portion of each well, including the portion that is drilled through any fresh water aquifers, will typically be drilled using either compressed air or freshwater mud as the drilling fluid.*[158]

The use of compressed air and WBM for drilling though the protected groundwater zones is best practice, as long as NYCRR also sets limits on the type of additives that can be mixed in the WBM formulation. WBM additives used when drilling through the protected groundwater zones should be non-toxic.

The 2011 RDSGEIS' use of the term "typically" indicates that use of compressed air and WBM for drilling though the protected groundwater zones may only occur a portion of the time. This is a best practice that should be implemented each time a well is drilled through protected groundwater zones.

While the 2011 RDSGEIS documents industry's position that it "typically" will use compressed air and WBM for the protection of groundwater, NYSDEC should *require* that practice and ensure that the requirement is codified in NYCRR. The proposed amendments to the NYCRR do not limit the types of drilling muds that can be used while drilling through protected groundwater zones. NYCRR should be revised to clearly prohibit the use of Oil-Based Muds (OBM) and Synthetic-Based Muds (SBM) drilling through protected groundwater zones and to limit additives used in the WBM to those that are non-toxic.

OBM contain diesel fuel or other hydrocarbons. SBM use synthetic oil. SBM are less harmful than OBM, but still contain materials that are toxic, bio-accumulate when discharged into water, and do not bio-degrade. For example, European nations prohibit the discharge of SBM to offshore waters, and prohibit their use when drilling through protected waters.[159] SBM are not approved by USEPA or Department of Energy for discharge offshore because they exceed USEPA's effluent limit guidelines.[160] The 2011 RDSGEIS incorrectly describes SBM as *"food-grade"* and *"environmentally friendly."*[161]

[158] 2011 NYSDEC, RDSGEIS, Page 5-32.

[159] Jonathan Wills, M.A., Ph.D., M.Inst.Pet., for Ekologicheskaya Vahkta Sakhalina, Muddied Waters A Survey of Offshore Oilfield Drilling Wastes and Disposal Techniques to Reduce the Ecological Impact of Sea Dumping, May 25, 2000.

[160] http://web.ead.anl.gov/dwm/techdesc/discharge/index.cfm.

[161] 2011 NYSDEC, RDSGEIS, Page 5-32.

Recommendation No. 40: 6 NYCRR § 554.1(c)(1) should be revised to limit the types of drilling muds that can be used while drilling through subsurface formations that contain protected groundwater. Drilling muds should be limited to Water-Based Muds (WBM) or drilling with air. Any additives required for safe drilling through the protected groundwater interval with WBM should be limited to additives that are bio-degradable, are non-toxic, and do not bio-accumulate. The SGEIS should also include this requirement as a mitigating measure.

Neither the 2011 RDSGEIS nor the proposed amendments to the NYCRR instruct the operator on how to properly dispose of drilling fluids. NYCRR requires a disposal plan and that drilling fluids be removed from the drillsite within 45 days; however, 6 NYCRR § 554.1(c)(1) does not provide specific instructions or criteria for acceptable drilling mud disposal plans. This problem was identified by HCLLC in 2009, and is still unresolved.

This problem is magnified in light of new language in the 2011 RDSGEIS that appears to contemplate allowing drilling muds to be spread on non-active agricultural fields and other soils. The 2011 RDSGEIS includes a discussion on proposed Agricultural District requirements. One of the requirements discussed is for "spent drilling muds to be removed from active agricultural fields." [162] The RDSGEIS is silent on provisions for non-active agricultural fields and other soils, and it is unclear what NYSDEC has planned for drilling mud disposal. NYSDEC should clarify its intentions in regards to spreading drilling muds.

The 2011 RDSGEIS correctly notes that drilling mud can be reconditioned and used at more than one well,[163] but it must eventually be disposed. Drilling muds may contain mercury, metals, NORM, oils, and other contaminates. This is especially true for Marcellus Shale operations where naturally occurring radioactive material is present in the shale drill cuttings and mud mixture. Therefore, drilling muds require proper handling and disposal. [164]

Solid waste management regulations at 6 NYCRR Chapter IV, Subchapter B (Solid Waste) provide the authority by which the state (through the Division of Solid and Hazardous Materials) establishes standards and criteria for solid waste management operations, including landfills and land application. However, the RDSGEIS is unclear on what NYSDEC has deemed to be the best management practices for handling drilling waste. A recent U.S. Department of Energy review of NYSDEC's drilling waste disposal regulations concluded:

> *"The [NYS]* ***DEC has developed no regulations, policies, or guidelines*** *governing slurry injection, subsurface injection, or annular disposal of drilling wastes and reserve-pit wastes [emphasis added]."*[165]

NYSDEC has not established regulations to minimize the generation of drilling waste (e.g. reuse, recycle), or established limits on the heavy metal content of drilling mud additives.

Regulations at 6 NYCRR § 554.1(c)(1) should be revised to provide specific instructions on drilling fluid handling and disposal. Questions that need to be addressed include: Where will drilling waste be taken for treatment and disposal? What tests will be run to characterize the waste stream for proper handling,

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[162] 2011 NYSDEC, RDSGEIS, Page 7-145.

[163] 2011 NYSDEC, RDSGEIS, Page 5-32.

[164] As explained in HCLLC's 2009 report, the mercury content in drilling mud for a Marcellus Shale well drilled to a depth of 5,000' could contain 0.5- 5.0 lbs of mercury per well, depending on barite quality, and drilling muds may also contain the heavy metal cadmium.

[165] U.S. Department of Energy, Drilling Waste Management Information System, http://web.ead.anl.gov/dwm/regs/state/newyork/index.cfm.

treatment, and disposal? Does the treatment capacity exist to handle this incremental waste in NYS? If so, where are the treatment facilities located? What types of treatments will be completed? What is the ultimate disposal location for the treatment byproducts?

Recommendation No. 41: 6 NYCRR § 554.1(c)(1) should be revised to provide specific instructions on the best practices for drilling mud handling and disposal. The SGEIS should also provide specific instructions on the best practices for drilling mud handling and disposal as a mitigating measure. See Chapter 13 of this report for additional recommended disposal solutions.

13. Reserve Pit Use & Drill Cuttings Disposal

Background: In 2009, HCLLC recommended that NYSDEC adopt regulations requiring closed-loop tank systems as best practice, instead of the use of temporary reserve pits to handle and store drill muds and cuttings, unless the operator demonstrates that closed-loop tank systems are not technically feasible. Additionally, HCLLC recommended that if temporary reserve pits are used, NYSDEC should adopt regulations that: require impermeable, chemical resistant liner material; limit the types of chemicals stored to those compatible with the liner material; require wildlife protection design standards; and establish firm removal and restoration requirements when drilling was completed. HCLLC recommended that cuttings not be buried onsite, and that waste be removed from the drilling location and properly disposed at an approved waste disposal facility capable of handling the quantity and type of waste generated.

HCLLC recommended that NYS consider the use of grind-and-inject technology to convert drill cuttings into a slurry that can be injected into a properly designed, approved subsurface disposal well. Additionally, HCLLC recommended that if reserve pits are determined to be the only technically feasible option for temporary waste storage, that storage of drilling waste be limited to un-contaminated drill cuttings, drilled using compressed air or water based-muds with non-toxic additives.

2011 RDSGEIS: The 2011 RDSGEIS recommends closed-loop tank systems as best practice in some circumstances, but in other circumstances defaults to the use of reserve pits, without demonstrating that reserve pits are environmentally preferable.

The RDSGEIS requires a closed-loop tank system for horizontal drilling operations in the Marcellus Shale that do not have an acceptable acid rock drainage (ARD) mitigation plan[166] for on-site cuttings burial; and drill cuttings that are coated with Synthetic-Based Muds (SBM) and Oil-Based Muds (OBM). In all other cases, the RDSGEIS proposes the use of reserve pits.

> *The revised draft SGEIS proposes to require, pursuant to permit conditions and/or regulation, that a closed-loop tank system be used instead of a reserve pit to manage drilling fluids and cuttings for:*
>
> - *Horizontal drilling in the Marcellus Shale without an acceptable acid rock drainage (ARD) mitigation plan for on-site cuttings burial; and*
> - *cuttings that, because of the drilling fluid composition used must be disposed off-site, including at a landfill.*[167]

Appendix 10, Proposed Supplementary Permit Conditions for HVHF, Condition No. 56 requires the operator to provide NYSDEC with an acid rock drainage mitigation plan if NYSDEC requests the plan. However, there is no specific criteria established to define what constitutes and acceptable acid rock drainage mitigation plan.

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[166] 2011 NYSDEC, RDSGEIS, Page 7-67.

[167] 2011 NYSDEC, RDSGEIS, Page 1-13.

Yet, the USGS recommends against onsite disposal because of the potential risk posed:

> *Onsite burial of drill cuttings at shale-gas development sites, which is allowable under the dSGEIS if oil-based drilling mud is not used, should be carefully considered. According to Lash and Engelder (2008), pyrite is abundant in the high-TOC basal intervals of the Marcellus Shale. Oxidation and leaching of pyritic shale produces and acidic, metals-rich discharge commonly referred to as AMD (Acid Mine Discharge). A multi-horizontal well site will generate 100 to 500 times the volume of AMD-producing pyritic shale cutting than that generated at a single-vertical well site.* ***<u>If these pyritic shale drill cuttings are left onsite, the potential for future surface-water and groundwater contamination is significant – removal and disposal of all cuttings at an approved landfill would be the preferred approach</u>*** *[emphasis added].*[168]

The RDSGEIS proposal to use reserve pits is internally inconsistent with the RDSGEIS' conclusion that closed-loop tank systems are environmentally preferable for the following reasons:

> *Depending on the configuration and design of a closed-loop tank system use of such a system can offer the following advantages:*
>
> - *Eliminates the time and expense associated with reserve pit construction and reclamation;*
> - *Reduces the surface disturbance associated with the well pad;*
> - *Reduces the amount of water and mud additives required as a result of re-circulation of drilling mud;*
> - *Lowers mud replacement costs by capturing and re-circulating drilling mud;*
> - *Reduces the wastes associated with drilling by separating additional drilling mud from the cuttings; and*
> - *Reduces expenses and truck traffic associated with transporting drilling waste due to the reduced volume of the waste.*[169]

Additionally, the 2011 RDSGEIS explains the environmental risks of reserve pits:

> ***<u>Pit leakage or failure could also involve well fluids</u>****. These issues are discussed in Chapters 8 and 9 of the 1992 GEIS, but are acknowledged here with respect to unique aspects of the proposed multi-well development method. The conclusions regarding pit construction standards and liner specifications presented in the 1992 GEIS were largely based upon the short duration of a pit's use.* ***<u>The greater intensity and duration of surface activities associated with well pads with multiple wells increases the potential for an accidental spill, pit leak or pit failure if engineering controls and other mitigation measures are not sufficient</u>****. Concerns are heightened if on-site pits for*

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[168] Testimony of John H. Williams, Ground-Water Specialist, U.S. Geological Survey, The Council of the City of New York Committee on Environmental Protection, Public Hearing, Draft Supplemental Generic Environmental Impact Statement Relating to Drilling for Natural Gas in New York State Using Horizontal Drilling and High-Volume Hydraulic Fracturing, October 23, 2009, Page 2.

[169] 2011 NYSDEC, RDSGEIS, Page 5-39.

> *handling drilling fluids are located in primary and principal aquifer areas, or are constructed on the filled portion of a cut-and-filled well pad [emphasis added].*[170]
>
> *As explained in Chapter 5, the total volume of drill cuttings produced from drilling a horizontal well may be about 40% greater than that for a conventional, vertical well to the same target depth. For multi-well pads, cuttings volume would be multiplied by the number of wells on the pad.* ***The potential water resources impact associated with the greater volume of drill cuttings from multiple horizontal well drilling operations would arise from the retention of cuttings during drilling, necessitating a larger reserve pit that may be present for a longer period of time, unless the cuttings are directed into tanks as part of a closed-loop tank system****[emphasis added].* [171]

The use of close-loop drilling waste handling system is a best practice. For example, New Mexico requires the use of closed-loop drilling systems.[172]

> **Recommendation No. 42**: The SGEIS and NYCRR should be revised to prohibit reserve pit use for Marcellus Shale drilling operations, and instead require closed-loop tank systems to collect drill cuttings and transport them to waste disposal facilities. NYCRR should make reserve pit use the exception, allowing it only in cases where closed-loop tank systems are determined to be technically infeasible. If reserve pits are determined to be the only technically feasible option, storage of drilling waste should be limited to un-contaminated drill cuttings from the section of the well drilled using compressed air or water based-muds with non-toxic additives. These best practices for drilling waste management should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

Of even greater concern is the RDSGEIS' proposal to allow drill cuttings to be buried onsite in some cases. Marcellus Shale cuttings contain Naturally Occurring Radioactive Materials (NORM) and are coated with drilling muds, including Water-Based Mud (WBM). The Marcellus Shale is considered a "highly radioactive" shale,[173] and its drill cuttings may require special hazardous waste handling and treatment. While the RDSGEIS proposes to allow on-site burial only of drill cuttings that were created by air drilling or WBM drilling operations, WBM may contain mercury, metals, and other contaminants.[174]

> *The Department has determined that drill cuttings are solid wastes, specifically construction and demolition debris, under the State's regulatory system. Therefore,* ***the Department would allow disposal of cuttings from drilling processes which utilize only air and/or water on-site,*** *at construction and demolition (C&D) debris landfills, or at municipal solid waste (MSW) landfills, while cuttings from processes which utilize any oil-based or polymer-based products could only be disposed of at MSW landfills [emphasis added].*[175]

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[170] 2011 NYSDEC, RDSGEIS, Page 6-16.

[171] 2011 NYSDEC, RDSGEIS, Page 6-65.

[172] New Mexico, Energy, Minerals and Natural Resources Department, Oil Conservation Division, Regulations at Title 19, Chapter 15, Part 17.

[173] Hill, D.G., Lombardi, T.E. and Martin, J.P., Fractured Shale Gas Potential in New York, 2002, p.8.

[174] As explained in HCLLC's 2009 report, the mercury content in drilling mud for a Marcellus Shale well drilled to a depth of 5,000' could contain 0.5- 5.0 lbs of mercury per well, depending on barite quality, and drilling muds may also contain the heavy metal cadmium.

[175] 2011 NYSDEC, RDSGEIS, Page 1-13.

The proposed revisions to NYCRR would require the reserve pit liner to be ripped and perforated as part of the onsite burial process (6 NYCRR § 560.7(c)); therefore, contaminated drill cuttings would be in direct contact with soils and surface waters.

While the RDSGEIS generally takes the position that WBM-coated cuttings can be stored in reserve pits and buried onsite, in some cases it waivers. It is not clear what additional limitations may be applied to WBM-coated drill-cuttings disposal. NYSDEC recognizes that onsite burial of chemical additives included in WBM may not be prudent. However, the RDSGEIS does not spell out criteria for determining what types of WBM-coated cuttings may and may not be stored and buried in reserve pits. The RDSGEIS proposes this decision be left to a later NYSDEC consultation process.

An example of how the RDSGEIS deviates from its general position that WBM-coated cuttings can be stored in reserve pits and buried onsite is as follows:

> *Supplementary permit conditions pertaining to the management of drill cuttings from high-volume hydraulic fracturing* ***require consultation with the Department's Division of Materials Management for the disposal of any cuttings associated with water-based mud-drilling and any pit liner associated with water-based or brine-based mud-drilling where the water-based or brine-based mud contains chemical additives.*** *Supplemental permit conditions also dictate that any cuttings required to be disposed of off-site, including at a landfill, be managed on-site within a closed-loop tank system rather than a reserve pit [emphasis added].*[176]

This uncertain position about what to do with WBM-coated drill cuttings is perpetuated in the proposed revisions to NYCRR at 6 NYCRR § 560.7(c):

> *Consultation with the department's Division of Materials Management (DMM) is required prior to disposal of any cuttings associated with water-based mud-drilling and pit liner associated with water-based mud-drilling where the water-based mud contains chemical additives.*

All WBM contains chemical additives. NYCRR must be clear on which chemical additives would trigger the use of closed-loop tanks and prohibit drill cuttings burial onsite.

Recommendation No. 43: The SGEIS and NYCRR should be clear about how WBM-coated drill cuttings will be handled and should not leave this unresolved. The standards for handling WBM-coated drill cuttings should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

Additionally, it is inefficient from a logistics and energy use standpoint to construct a reserve pit for the temporary storage of drill cuttings, and then remove this pit at a later time. It is substantially more efficient to use a closed-loop tank system to collect the drill cuttings, because the cuttings can be directly transported to a waste handling facility. The RDSGEIS agrees with the efficiencies gained through closed-loop tank systems, but incongruously does not recommend them in all cases.

[176] 2011 NYSDEC, RDSGEIS, Page 7-67.

> *The 1992 GEIS discusses the use of reserve pits and tanks, either alone or in conjunction with one another, to contain the cuttings and fluids associated with the drilling process. Both systems result in complete capture of the fluids and cuttings; however the use of tanks in **closed-loop tank systems facilitates off-site disposal of wastes while more efficiently utilizing drilling fluid and providing additional insurance against environmental releases** [emphasis added].* [177]
>
> *The design and configuration of closed-loop tank systems will vary from operator to operator, but all such systems contain drilling fluids and cuttings in a series of containers, thereby eliminating the need for a reserve pit….the objective is to fully contain the cuttings and fluids in such a manner as to prevent direct contact with the ground surface or the need to construct a lined reserve pit.*[178]

NYSDEC's proposal for onsite burial of contaminated drill cuttings becomes even more paradoxical when the RDSGEIS concludes that operators have not proposed onsite burial of drill cuttings.

> ***Operators have not proposed on-site burial of mud-drilled cuttings**, which would be equivalent to burial or direct ground discharge of the drilling mud itself. Contaminants in the mud or in contact with the liner if buried on-site could adversely impact soil or leach into shallow groundwater [emphasis added].*[179]

A portion of the well drilled will generate cuttings that do not contain NORM. However, as identified in the RDSGEIS, the Marcellus contains NORM and cuttings drilled during this section of the well would require special handling and disposal.

Recommendation No. 44: The SGEIS and NYCRR should prohibit the onsite burial of drill cuttings. If onsite burial is permitted, it should be limited to cuttings that do not have any NORM and are not coated with drill muds containing mercury, heavy metals, and other chemical additives.

Cuttings Reinjection (CRI) Technology, also referred to as "grind-and-inject technology" is commonly used by industry as a best practice to avoid the need for long-term onsite burial of drill cuttings. CRI technology converts drill cuttings into a slurry that can be injected into a subsurface disposal well. CRI also provides a waste disposal method for used drilling mud, because mud can be used in the slurry formulation to reduce supplemental water needs. Currently, NYS does not have sufficient waste disposal wells to handle the anticipated Marcellus Shale drilling waste volume. Either NYS would need to rely on permitted waste handling capacity at wells out of state, or would need to permit and drill wells to meet that need if there are geologically, hydrologically, and otherwise appropriate locations for such wells in NYS.

For example, CRI is commonly used in Alaska as a best practice to avoid use of long-term reserve pit use and surface burial of contaminated drill cuttings. Waste is collected, ground into a slurry, and injected into a subsurface disposal well.[180] If an injection well is not available at a well location, operators have

[177] 2011 NYSDEC, RDSGEIS, Page 5-37.

[178] 2011 NYSDEC, RDSGEIS, Page 5-37.

[179] 2011 NYSDEC, RDSGEIS, Page 6-66.

[180] BP Exploration (Alaska), Inc., ARCO Alaska, Inc. and ConocoPhillips, Inc. have published numerous technical papers on grind and injection technology, and the success of disposal wells as a pollution prevention measure in the SPE trade journals, and at industry conferences.

collected wastes and transported them back to an injection well location. Operators that do not have their own waste handling facilities or disposal wells typically negotiate an agreement with another operator or a service provider to use its disposal facilities. As a result of this best practice implementation in Alaska, DOE reports there are 58 active Class II-D (disposal) wells and six Class I wells in Alaska.[181]

NYS would need to permit construction of a sufficient number of Class I and Class II injection wells to ensure that there was sufficient capacity for the types and amounts of waste generated.

In addition to the environmental mitigation benefit, CRI technology reduces future liability for industry operators, and has been determined to be an environmentally-appropriate method for handling drilling waste containing NORM by both Shell and Chevron.[182]

Halliburton, an industry service provider, agrees that CRI technology makes business and environmental sense as compared to long-term drilling waste burial at the surface.

> *While it is true that new technology comes with a price tag, and much of the technology used in drilling waste management has been introduced in the last 10 years, many technologies now available to operators **are clearly cost effective when the entire well construction cost is evaluated**.*
>
> *The cost of making a mistake and having either an expensive remediation project or a potential liability nearly always significantly outweighs the cost of a good preventative drilling waste management program. Further, compliance with current environmental regulations does not always guarantee immunity in the future…*
>
> *Numerous examples exist of industries having to clean up sites that were fully compliant with all regulations at the time the waste was generated and disposed of….*
>
> *The paper demonstrates that the correct application of these technologies combined with a holistic approach to drilling waste management and drilling fluid operations results in a net reduction in well construction costs and a reduction in the potential for environmental liability…*
>
> *… environmental compliance (whether internally or externally driven) is not the only reason to utilize these types of technologies and services [emphasis added].*[183]

International operators report favorable economics for eliminating exploration and production waste by deep well injection. For example, a 2001 Advantek International Corp. report concludes:

> *Downhole disposal of mud and cuttings waste through hydraulic fracturing provides a zero discharge solution and eliminates future cleanup liabilities…This downhole disposal technology has shown success in both onshore and offshore drilling operations and is*

[181] Puder, M.G., Bryson, B., Veil, J.A, Argonne National Laboratory, "Compendium of Regulatory Requirements Governing Underground Injection of Drilling Wastes," Prepared for the U.S. Department of Energy, February 2003, Page 17.

[182] Okorodudu, A., Akinbodunse, A., Linden, L., Chevron Nigeria Ltd, Anwuri, L., Shell Petroleum Development Co. Nigeria Ltd., Irrechukwu, D.O., Zagi, M.M., Nigeria Department of Petroleum Resources, Guerrero, H., M-I Swaco, "Feasibility Study of Cuttings-Injection Operation: A Case Study of the Niger Delta Basin," SPE Paper 98640, presented at the SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production in Abu Dhabi, U.A.E., April 2006,Page 2.

[183] Browing, K., Seaton, S., Halliburton Fluid Systems, "Drilling Waste Management: Case Histories Demonstrate that Effective Drilling Waste Management Can Reduce Overall Well-Construction Costs," SPE Paper 96775, presented at the 2005 SPE Annual Technical Conference and Exhibition in Dallas Texas, October 2005, Pages 1, 3, & 4

becoming a routine disposal option…It also offers favorable economics [emphasis added].[184]

The U.S. Department of Energy (DOE) also advocates CRI technology:

Because wastes are injected deep into the earth below drinking water zones, proper slurry injection operations should pose lower environmental and health risks than more conventional surface disposal methods.[185]

In 1990, the United States passed the Pollution Prevention Act, establishing a national policy that places priority on pollution prevention and specifies that disposal into the environment should only be allowed as a **last resort**:

The Congress hereby declares it to be the national policy of the United States that pollution should be prevented or reduced at the source whenever feasible; pollution that cannot be prevented should be recycled in an environmentally safe manner, whenever feasible; pollution that cannot be prevented or recycled should be treated in an environmentally safe manner whenever feasible; and ***disposal or other release into the environment should be employed only as a last resort*** *and should be conducted in an environmentally safe manner[emphasis added].”*[186]

Additionally, the amount of drill-cutting waste generated can be significant. If CRI technology is not used to dispose of this waste by deep well injection, than surface waste disposal sites will need to be utilized to handle this waste. The RDSGEIS estimates the amount of waste generated for each well:

For example, a vertical well with surface, intermediate and production casing drilled to a total depth of 7,000 feet produces approximately 154 cubic yards of cuttings, while a horizontally drilled well with the same casing program to the same target depth with an example 4,000-foot lateral section produces a total volume of approximately 217 cubic yards of cuttings (i.e., about 40% more). A multi-well site would produce approximately that volume of cuttings from each well.[187]

Recommendation No. 45: NYS should consider the use of grind-and-inject technology to convert drill cuttings into a slurry that can be injected into a subsurface disposal well, and work with industry to permit a sufficient number of drilling waste disposal wells to safely meet this need. The use of Cuttings Reinjection (CRI) technology for drilling waste management should be included in the SGEIS as a mitigation measure and codified in the NYCRR, as an environmentally preferable option to onsite-disposal of drilling waste.

[184] Abou-Sayed, A., SPE, Advantek International, Guo, Q., SPE, Advantek International, “Design Considerations in Drill Cuttings Re-Injection Through Downhole Fracturing,” IADC/SPE Paper 72308, Presented at the IADC/SPE Middle East Drilling Technology Meeting in Bahrain, October 2001, Page 1.

[185] Argonne National Laboratory, “An Introduction to Slurry Injection Technology for Disposal of Drilling Wastes,” Publication prepared for the U.S. Department of Energy, September 2003, Page 2.

[186] Pollution Prevention Act of 1990, U.S. Code, Title 42, Public Health and Welfare, Chapter 133, Pollution Prevention.

[187] 2011 NYSDEC, RDSGEIS, Page 5-34.

14. HVHF Flowback Surface Impoundments at Drillsite

Background: In 2009, HCLLC recommended that the NYCRR require fracture fluid flowback be routed to onsite treatment systems for fracture fluid recycling and/or collected in closed-loop tanks for transportation to offsite treatment systems. Surface impoundments should not be used for fracture fluid flowback.

2011 RDSGEIS: The 2011 RDSGEIS made excellent revisions that address public concerns and are protective of human health and the environment by clearly prohibiting HVHF flowback waste impoundments at drillsites. The 2011 RDSGEIS recommends the use of closed-loop tank systems at the drillsites for collecting waste before transporting it to a treatment location, or recycling it for use on another well:

> *Flowback water stored on-site must use covered watertight tanks within secondary containment and the fluid contained in the tanks must be removed from the site within certain time periods.*[188]
>
> *The Department proposes to require that operators storing flowback water on-site would be required to use watertight tanks located within secondary containment, and remove the fluid from the wellpad within specified time frames.*[189]

NYCRR Proposed Revisions: Proposed regulations at 6 NYCRR § 560.6(c)(27) specifically prohibit HVHF flowback from being directed to or stored in any on-site pit, and require covered watertight tanks to handle flowback at the drillsite. Furthermore, 6 NYCRR § 750-3.4(b) prohibits the issuance of a State Pollutant Discharge Elimination System (SPDES) permit without prior certification that HVHF flowback fluids will be not be directed to or stored in a pit or impoundment. Proposed regulations at 6 NYCRR § 560.3(a)(10)-(11) also require an operator to provide a description of the closed-loop tank system it will use and the number of receiving tanks it will employ for flowback water.

No further recommendations. The RDSGEIS includes the use of closed-loop tank systems, which is best available technology.

[188] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 25.

[189] 2011 NYSDEC, RDSGEIS, Page 1-12.

15. HVHF Flowback Centralized Surface Impoundments Off-Drillsite

Background: In 2009, HCLLC recommended that the NYCRR prohibit the use of centralized surface impoundments for HVHF flowback. This recommendation was made because it is best technology to eliminate the use of surface impoundments altogether, rather than gathering HVHF flowback into tanks at the drillsite and then moving it by pipeline or truck to be pumped into a larger open impoundment at a centralized location away from drillsites. If flowback is recycled, it should be trucked or piped from tank–to–tank to another drillsite or used at the same drillsite in a different well.

Eliminating use of centralized surface impoundments prevents: large scale surface disturbance that requires multi-year rehabilitation[190]; the potential for leakage to occur through or around the liner, impacting ground water; and the potential to generate substantial amounts of hazardous air pollution.

A centralized surface impoundment photograph in Pennsylvania is shown below.

Bednarski Centralized Waste Impoundment, Pennsylvania, Site Permit PADEP, 798407

The most serious concern with the use of centralized surface impoundments for HVHF flowback is the amount of hazardous air pollution predicted for these centralized surface impoundments. In 2009, NYSDEC estimated that each centralized impoundment would be a major source of hazardous air pollution, emitting more than 32.5 tons of air toxics per year, and it was unclear if NYSDEC's estimate was even a worst-case estimate:

[190] Surface disturbance is less for temporary tanks than impoundments. Impoundments require surface soil excavation and multi-year rehabilitation. Temporary tanks used at the drillsite use existing gravel space already in place for drilling operations rather that impacting new and additional surface terrain away from the drillsite.

> *Based on an assumed installation of ten wells per wellsite in a given year, an annual methanol air emission [estimate] of* ***32.5 tons*** *(i.e.,"****major" quantity of HAP****) is theoretically possible at a central impoundment*[191] *[emphasis added].*

USEPA classifies a major source of hazardous air pollution as a source that emits more than 25 tons per year. These centralized impoundments have been sited nearby residential homes and community facilities in other states, increasing the amount of hazardous air pollution exposure to nearby humans, including increased exposure to benzene, a known human carcinogen.

In January 2011, NYS' consultant, Alpha Geoscience, complimented HCLLC for its recommendations on flowback impoundments, and supported improved mitigation:

> *Harvey Consulting has thoroughly documented their discussion of surface flowback impoundments and hazardous air pollutants, citing a professional journal article, technical guidance documents, consultant reports, and NYSDEC documents.* [192]

2011 RDSGEIS: The 2011 RDSGEIS states that centralized flowback impoundments are "not contemplated" by industry.[193]

> ***The Department was informed in September 2010 that operators would not routinely propose to store flowback water either in*** *reserve pits on the wellpad or in* ***centralized impoundments****. Therefore, these practices are not addressed in this revised draft SGEIS and such impoundments would not be approved without site-specific environmental review [emphasis added].*[194]

This industry representation is inconsistent with the actual practice of operators in Pennsylvania. Moreover, neither the RDSGEIS nor the proposed NYCRR amendments prohibit the use of centralized flowback impoundments. This leaves the door open for centralized flowback impoundments to be approved if a site-specific environmental review is conducted.

NYSDEC's requirement to use closed-loop HVHF flowback collection tanks at each drillsite is an efficient collection method, because fluid can be easily transferred to a treatment and disposal location, or taken to another well for reuse. It would not be efficient, or environmentally sound, to collect HVHF waste in a closed-loop flowback tank at the drillsite, and then transfer that waste by temporary piping or truck to a large centralized surface impoundment off of the drillsite location.

Recommendation No. 46: The SGEIS and NYCRR should prohibit the use of centralized surface impoundments for HVHF flowback based on the known impacts examined in the SGEIS process. HVHF flowback waste should be collected at the wellhead and recycled or directly routed to disposal. This prohibition should be described in the SGEIS as a mitigation measure and codified in the NYCRR.

[191] 2009, NYSDEC, DSGEIS, Page 6-56.

[192] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 31.

[193] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 15.

[194] 2011 NYSDEC, RDSEGIS, Page 1-2.

If NYSDEC does not prohibit the use of centralized impoundments, the SGEIS should analyze the impacts and propose mitigation to protect public health and the environment. The decision to allow centralized flowback impoundments should not be segmented from the SGEIS just because it is known to create significant impacts. Prohibiting the use of centralized impoundments mitigates that known risk.

16. Repeat HVHF Treatment Life Cycle Impacts

Background: In 2009, HCLLC recommended that the DSGEIS disclose how many times a well may be fracture treated over its life, and provide a worst case scenario for water use and waste disposal requirements based on this scenario. HCLLC pointed out that the 2009 DSGEIS estimated water use and waste volumes based on a single initial fracture treatment and that this approach does not consider the fact that most shale gas wells require multiple fracture treatments.

2011 RDSGEIS: The 2011 RDSGEIS indicates there may be a potential for repeated HVHF treatments over the life of the well.[195] However, the 2011 RDSGEIS does not quantify the number of HVHF treatments possible per well, nor does it estimate the peak or cumulative impact of these HVHF treatments. Therefore the RDSGEIS under-predicts both the peak and cumulative impacts by not examining the reasonably foreseeable likelihood that Marcellus, Utica, and other low-permeability shale reservoirs will require more than one HVHF treatment, most likely two or three, over a several decade long lifecycle.

NYSDEC does acknowledge that, when Marcellus repeat HVHF treatments are conducted, the impact will be equivalent to the initial treatment. However, its impact assessment does not examine the peak or cumulative impacts that may occur:

> *Regardless of how often it occurs, **if the high-volume hydraulic fracturing procedure is repeated it will entail the same type and duration of surface activity at the well pad as the initial procedure** [emphasis added].* [196]

For example, NYSDEC estimates 1,600 or more wells to be drilled and completed per year,[197] estimating a 30 year development life cycle,[198] for a total of 48,000 wells. NYSDEC estimates each HVHF treatment to use an average 4,200,000 gallons per well,[199] and that approximately 9-35% of HVHF treatment returns to the well and is produced as waste that requires handling, treatment and/or disposal. [200] A single HVHF treatment in each well, over a thirty year period, could yield a total waste load of 18-71 billion gallons. That waste volume could double or triple if two or three fracture treatments are conducted on each well over a several decade period. Assuming at least two fracture treatments, and possibly three may be implemented, the waste volumes would increase substantially, possibly exceeding 200 billion gallons.

NYSDEC acknowledges the fact that repeated HVHF treatments have been required in the Barnett shale, typically within 5 years from the initial HVHF.[201] However, NYSDEC notes:

> *Marcellus operators with whom the Department has discussed this question have stated their expectation that refracturing will be a rare event.*[202]

[195] 2011 NYSDEC, RDSGEIS, Page 6-275.
[196] 2011 NYSDEC, RDSGEIS, Page 5-99.
[197] 2011 NYSDEC, RDSGEIS, Page 2-1.
[198] 2011 NYSDEC, RDSGEIS, Page 6-6.
[199] 2011 NYSDEC, RDSGEIS, Page 6-10.
[200] 2011 NYSDEC, RDSGEIS, Page 5-99.
[201] 2011 NYSDEC, RDSGEIS, Page 5-98.
[202] 2011 NYSDEC, RDSGEIS, Page 5-98.

The information NYDEC gathered from a few Marcellus operators, that concludes Marcellus shale re-fracturing will be "rare", is inconsistent with industry literature.

For example, in 2010 Range Resource published a Society of Petroleum Engineering technical paper that describes two successful horizontal shale re-fracture re-stimulations and explains that Marcellus re-fracture stimulations will be used:

> *Based on the success of horizontal re-fracs in other shale plays, re-fracture stimulations in the Marcellus will be an excellent option to maximize fracture complexity and increase the total effective fracture network. …These re-fracs can be utilized to soften overall field decline in future years…'*[203]

In 2006, Schlumberger, an Oil & Gas Service Company, published a Society of Petroleum Engineering technical paper describing the benefits of re-fracture re-stimulations to increase hydrocarbon production in wells that were initially fractured and where hydrocarbon production had declined to a point that it was economically attractive to repeat the fracture stimulation procedure in that same well:

> *A successful refracturing treatment is one that creates a fracture having higher fracture conductivity and/or penetrating an area of higher pore pressure than the previous fracture.*[204]

Schlumberger explains that re-fracture re-stimulations are likely in wells that have the following characteristics: low productivity relative to other wells with comparable pay; remaining reserves in place; need for fracture reorientation to improve hydrocarbon production; poorly placed initial fracture treatment (e.g. proppant crushing, or proppant flowback, use of incompatible fluids); and reservoir complexity leading to poor hydrocarbon recovery.

A 2010 Apache Corporation, Society of Petroleum Engineering paper, agrees that re-fracture re-stimulations will play an important role in shale stimulation for some time to come. Apache Corporation explains that re-fracture re-stimulations are being used in shale wells to increase gas production, and to make good wells even better gas producers:

> *Refracs of even good wells increased the recovery and re-established near initial production rate. Increasing stimulated reservoir volume should increase both the IP*[205] *and EUR*[206]*. When new areas of the shale are exposed in a refrac, there should also be a gain in reserves (Warpinski, 2008). Increases in stimulated reservoir volume could be accomplished by opening many of the micro-cracks and laminations within the undisturbed matrix blocks in the initial drainage [area] that were left unstimulated by previous fracturing attempts. Re-opening of natural and hydraulic fractures that had closed due to overburden and confining stress created by depletion would re-establish matrix area contact.*[207]

[203] Curry, M., and Maloney, T., Range Resources Corp., Woodroof, R., and Leonard, R. ProTechnics Division of Core Laboratories, Less Sand May Not Be Enough, Society of Petroleum Engineers Technical Paper, SPE 131783, 2010. Page 12.

[204] Moore, L.P., Ramakrishnan, H,, Schlumberger, Restimulation: Candidate Selection Methodologies and Treatment Optimization, Society of Petroleum Engineers Technical Paper, SPE 102681, 2006. Page 1.

[205] IP= Initial Production.

[206] EUR= Expected Ultimate Recovery.

[207] King, G.E., Apache Corporation, Thirty Years of Gas Shale Fracturing: What Have We Learned?, Society of Petroleum Engineers Technical Paper, SPE 133456, 2010. Page 24.

Re-fracture re-stimulation has been used widely in the Barnett Shale. Many technical papers report successful re-fracture re-stimulations in the Barnett Shale where improved HVHF slickwater fractures were used as a second treatment after the initial cross-linked gel fracture treatment. While the Marcellus and Utica Shales in NYS will start with improved HVHF slickwater fracture treatments, these treatment methods will continue to improve over time, and like the Barnett, repeat fracture treatments will be required to improve hydrocarbon performance as new and improved fracture treatment design supplants existing technology. Apache Corporation explains:

> *Fracturing technology for shales is constantly improving and refracs may slowly fade from common use as the frac designs for shale wells are optimized.* ***<u>Until optimal fracs are achieved and production engineering is optimized, however, refracs will have a place in shale stimulation</u>*** *[emphasis added].*[208]

Additionally, NYSDEC acknowledges the benefits of re-fracture treatment:

> *Several other reasons may develop to repeat the fracturing procedure at a given well. Fracture conductivity may decline due to proppant embedment into the fracture walls, proppant crushing, closure of fractures under increased effective stress as the pore pressure declines, clogging from fines migration, and capillary entrapment of liquid at the fracture and formation boundary. Refracturing can restore the original fracture height and length, and can often extend the fracture length beyond the original fracture dimensions.* [209]

Recommendation No. 47: The SGEIS should quantify how many times a well may be fracture treated over its life, and provide a worst case scenario for water use and waste disposal requirements based on this scenario. Additionally, the SGEIS should examine the peak and cumulative impacts of multiple HVHF treatments over a well's life and propose mitigation to offset those reasonably foreseeable impacts.

[208] King, G.E., Apache Corporation, Thirty Years of Gas Shale Fracturing: What Have We Learned?, Society of Petroleum Engineers Technical Paper, SPE 133456, 2010. Page 24.

[209] 2011 NYSDEC, RDSGEIS, Page 5-98.

17. Air Pollution Control and Monitoring

Air Quality Impact Assessment Modeling Analysis:

In 2009, AKRF's comments on the 2009 DSGEIS (prepared for NRDC) identified a number of shortcomings in the air quality impact assessment modeling analysis. Notably, that emissions from 10 wells per year and simultaneously operating equipment would produce emission impacts that exceed the NAAQS.

The 2011 RDSGEIS: The 2011 RDSGEIS includes a substantial amount of new modeling work and a number of operational restrictions and limitations to ensure that NAAQS are not violated. While the RDSGEIS has been significantly improved in this area, some problems with the analysis persist, and some new problems have developed.

The following assumptions used in the air quality impact assessment modeling analysis warrant further review and justification:

- The modeling analysis assumes that a maximum of four wells per drillsite will be drilled each year.[210] However, NYS ECL § 23-0501 requires development of all infill drilling within three years of the first well drilled, and the RDSGEIS envisions the Marcellus Shale gas reservoir will be developed from a multi-well pad for a 640-acre spacing unit, with 40-acre spacing. At 40-acre spacing density, 16 wells would need to be drilled in three years to fill a 640-acre unit, meaning that a maximum of 5-6 wells could possibly be drilled per year. This conflicts with the 4 wells per year (12 wells for three years) assumption and would generate more significant air quality impacts than contemplated by the RDSGEIS.
- Gas compositional data used in the modeling analysis was based on Marcellus Shale gas only. There was no analysis of Utica Shale gas or gas from any other low-permeability gas reservoir.[211] Modeling should be based on a reasonable worst case scenario that includes analysis of all shale formations with development potential, not just the Marcellus Shale, if the SGEIS proposes to cover more reservoirs.
- The modeling analysis assumed that there will be no emissions of criteria pollutants from venting. However, the RDSGEIS proposes to allow gas venting of up to 5 MMscf during any consecutive 12-month period, including sour gas, as long as it is vented at least 30 feet in the air. This allowance undermines the assumption that no criteria pollutants would be emitted during venting.
- The modeling analysis assumes only three days of gas flaring per well. However, the RDSGEIS states that flaring can occur for up to a month in some cases. [212] Therefore, the modeling understates the potential emissions from flaring.

[210] 2011 NYSDEC, RDSGEIS, Page 6-104.

[211] 2011 NYSDEC, RDSGEIS, Page 6-115.

[212] 2011 NYSDEC, RDSGEIS, Table 5.29 on Page 5-136 shows that well cleanup and testing can take 12 hours to 30 days. Modeling on Page 6-192 only assumes 3 days of flaring.

- The supplemental 24-hour $PM_{2.5}$ model impacts analysis did not evaluate simultaneous operation of equipment operating on the pad. However, other short-term impact assessment assumed simultaneous operation of one well drilling, one well completion and one well flaring, along with operation of the on-site line heater and off-site compressor for the gas production phase for previously-completed wells.[213] Therefore, the 24-hour $PM_{2.5}$ impact modeling is based on inconsistent assumptions.

- To account for the possibility of simultaneous well operations at nearby pads, a simplified sensitivity analysis was performed in the RDSGEIS to determine the potential contribution of an adjacent pad to the modeled impacts.[214] This modeling assumed a single adjacent pad, located one kilometer away (0.62 miles), with identical equipment and emissions as the modeling target pad.

  The RDSGEIS model only examined the potential for two multi-well drillsites, drilling horizontal wells to be located near each other at a distance of 0.62 miles apart. The modeling analysis assumed that only two drillsites would be operating nearby each other, and that drillsite development in an area would occur in a sequential fashion,[215] which is not always the case (especially when there are multiple operators developing an area).

  The modeling analysis did not evaluate the possibility of more than two multi-well drillsite drilling and completion operations adjacent to each other, nor did it evaluate the possibility of multi-well drillsites operating nearby several single well drilling and completion operations drilled on 40 acre spacing. Nor did the analysis examine the possibility that the surface location of multi-well drillsites could be positioned closer than 0.62 miles apart.

  NYS does not require drillsites to be located over the drilling unit, as long as surface siting approval is authorized. Therefore there is a possibility for drillsites to be located closer than 0.62 miles, a possibility of simultaneous operation of more than two drillsites at a time, and a possibility that more significant overlapping ambient air pollution impacts may occur than modeled. Therefore, the RDSGEIS did not consider the reasonable worst case scenario air impacts resulting from simultaneous operations of spatially proximate well sites. NYSDEC wither needs to examine all possible concurrent operation impacts, or prohibit the possibility.

- Mobile source impact assessment under-predicts the number of miles that will be driven by heavy equipment to transport supplies to and haul wastes away from drillsites, especially wastewater that is hauled out of state to treatment and disposal facilities. Modeling for mobile source air impacts resulting from wastewater transport must be consistent with reasonable worst case scenario forecasts of wastewater volume (which impacts the number of truck trips needed per well site) as well as forecasted in and out of state disposal options (which impacts distance traveled per disposal).

  The RDSGEIS assumes that both light and heavy duty trucks will only travel 20-25 miles[216] one way, yet out-of-state treatment and disposal facilities may be located several hundred miles away. For rural operations, it is unlikely that supplies, equipment, specialty contractors, lodging, and other support equipment and personnel will be located within 20-25 miles of the drillsite.

[213] 2011 NYSDEC, RDSGEIS, Page 6-124.

[214] 2011 NYSDEC, RDSGEIS, Page 6-127.

[215] 2011 NYSDEC, RDSGEIS, Page 6-136.

[216] 2011 NYSDEC, RDSGEIS, Page 6-176.

- The modeling analysis assumes that there will be no simultaneous operations of well drilling and completion equipment on a drillsite. There is a permit requirement prohibiting simultaneous operations;[217] however, this requirement is not codified in the proposed revisions to NYCRR.[218]

Recommendation No. 48: The RDSGEIS air quality impact assessment modeling analysis assumptions warrant additional review and justification. Limitations used in the modeling assumption must all be translated into SGEIS as mitigation measures and codified in the NYCRR to ensure the assumed impacts will not be exceeded. This was done in some cases, but not all. In the cases where modeling assumptions used cannot be justified, modeling revisions will be needed to examine impacts and identify required mitigation, or operational limits set.

Air Quality Monitoring Program:

In 2009, AKRF recommended improved air dispersion modeling and a region-wide emissions analysis. In response, NYSDEC completed a significant amount of additional work on the air quality section of the RDSGEIS. A major conclusion from this work was that there is insufficient information to understand the consequences of increased regional NO_x and VOC emissions on the resultant levels of ozone and $PM_{2.5}$. As a result of this lack of data, these impacts were not fully quantified by modeling alone. Furthermore, NYSDEC concluded that ambient air quality monitoring program is needed.

While implementation of a ambient air quality monitoring program, is an important improvement in the RDSGEIS, the proposed program needs further definition, a funding commitment, and a formal industry compliance obligation.

The 2011 RDSGEIS: The 2011 RDSGEIS includes a commitment to implement local and regional air quality monitoring:[219]

> ***<u>The Department also developed an air monitoring program to fully address potential for adverse air quality impacts beyond those analyzed in the dSGEIS, which are either not fully known at this time or not verifiable by the assessments to date.</u>*** *The air monitoring plan would help determine and distinguish both the background and drilling related concentrations of pertinent pollutants in the ambient air [emphasis added].*[220]
>
> *The dSGEIS identifies additional mitigation measures designed to ensure that emissions associated with high-volume hydraulic fracturing operations do not result in the exceedance of any NAAQS. In addition,* ***<u>the Department has committed to implement local and regional level air quality monitoring at well pads and surrounding areas</u>*** *[emphasis added].*[221]

[217] 2011 NYSDEC, RDSGEIS, Appendix 10, Attachment A, Condition 2.
[218] 2011 NYSDEC, RDSGEIS, Page 6-115.
[219] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 23.
[220] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 16.
[221] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 23.

Although Section 6.5.4 of the RDSGEIS proposes alternative methods for implementing air quality monitoring, it does not settle on a recommended solution.[222] The RDSGEIS proposes two alternatives: (1) industry-led monitoring with NYSDEC oversight, or (2) NYSDEC monitoring with industry funding. The RDSGEIS identifies NYSDEC monitoring with industry funding as the preferred alternative without making clear how this goal will actually be funded and implemented.

Table 6.24 proposes to: add a single air monitoring trailer and mobile laboratory to monitor ozone, particulate matter, oxides of nitrogen and air toxics; use infrared cameras to monitor gas leaks; and conduct summa canister sampling for BTEX and other VOCs. However, the RDSGEIS does not explain how the addition of a single mobile trailer and lab along with some other intermittent sampling will provide sufficient information to understand the consequences of increased regional NO_x and VOC emissions on the resultant levels of ozone and $PM_{2.5}$.

The RDSGEIS did not evaluate the possibility of installing permanent monitoring locations at numerous locations in NYS, with priority in existing non-attainment areas, and areas that will be heavily impacted by shale gas development. Instead, the RDSGEIS only proposes to examine "regional level" monitoring by collecting data at two sites in NYS.[223] This proposal is insufficient because monitoring regional ambient air quality is not possible with the limited data provided by a two-site program, proposed for an unspecified time period.

More information is needed to understand the scope and duration of NYSDEC's proposed air monitoring program. A more rigorous monitoring program proposal is needed that identifies: the scope of the monitoring program; the location of the monitoring sites; the amount of equipment and personnel needed to run each site; the duration of monitoring proposed at each site; along with the cost. It is anticipated that a program used to assess both regional and local impacts will require long term monitoring stations placed in key locations, not just infrequent and unrepresentative sampling.

The obligation to fund the air quality monitoring program needs to be clearly tied to a permit condition requirement—for example, the permit to flare or spud a well should require a contribution to an air quality monitoring fund; such a requirement is not set forth in either Appendix 6 or Appendix 10.

Recommendation No. 49: The SGEIS should include a more rigorous air monitoring program to achieve NYSDEC's goal of regional and local air pollutant impact monitoring. The proposed program should identify: the scope of the monitoring program; the location of the monitoring sites; the amount of equipment and personnel needed to run each site; the duration of monitoring proposed at each site; along with the cost. The SGEIS should require the monitoring program to commence prior to Marcellus Shale gas development to verify background levels and continue until NYSDEC can scientifically justify that data collection is no longer warranted, in consultation with EPA. The obligation to fund the air monitoring program needs to be clearly tied to a permit condition requirement.

The RDSGEIS acknowledges that air monitoring may identify peak or cumulative air pollution impacts that warrant additional emission controls. For example, NYSDEC has identified that:

> *…the consequences of the increased regional NOx and VOC emissions on the resultant levels of ozone and PM2.5 cannot be fully addressed by only modeling at this stage due to the lack of detail on the distribution of the wells and compressor stations. In addition, any potential emissions of certain VOCs at the well sites due to fugitive emissions,*

[222] 2011 NYSDEC, RDSGEIS, Page 6-180 through 6-184.

[223] 2011 NYSDEC, RDSGEIS, Page 6-181.

> *including possible endogenous level, and from the drilling and gas processing equipment at the compressor station (e.g. glycol dehydrators) are not fully quantifiable.*[224]

However, the RDSGEIS does not explain NYSDEC's plan to collect data, identify the potential for air pollutants to exceed the federal, state or local air pollution control standards, or require these additional emission controls in a timely manner before adverse impacts are realized by humans or the surrounding ecosystem.

> **Recommendation No. 50**: The SGEIS should explain NYSDEC's plan to collect data, identify the potential for pollution problems to exceed the federal, state or local air pollution control standards, and the timely installation of additional emission controls, in order to protect against exceedances of pollution control standards, should be required as an SGEIS mitigation measure and codified in the NYCRR.

GHG Impacts Mitigation Plan:

In 2009, HCLLC and AKRF recommended further analysis of Greenhouse Gas (GHG) impacts and mitigation. In response, NYSDEC acknowledged the potential for GHG emissions impacts and the need for mitigation. While such acknowledgement represents a substantial improvement from the 2009 draft, the proposed mitigation needs improvement to ensure the requirements are clear, measureable and enforceable.

The 2011 RDSGEIS: The 2011 RDSGEIS requires a GHG Impacts Mitigation Plan. [225]

> *The Plan must include: a list of best management practices for GHG emission sources for implementation at the permitted well site; a leak detection and repair program; use of EPA's Natural Gas Star best management practices for any pertinent equipment; use of reduced emission completions that provide for the recovery of methane instead of flaring whenever a gas sales line and interconnecting gathering line are available; and a statement that the operator would provide the Department with a copy of the report filed with EPA to meet the GHG Reporting Rule.*[226]

The GHG Impacts Mitigation Plan requires the operator to implement a Leak Detection and Repair Program,[227] use Reduced Emission Completions,[228] use EPA Natural Gas STAR program recommendations, and identify other best management practices.

The requirement that a GHG Impacts Mitigation Plan be prepared and include the use of best management practices for GHG control is a step in the right direction; however, given the variety of best management practices under EPA's voluntary Natural Gas STAR program, NYSDEC should require that well operators select and install the controls that will achieve the greatest emissions reductions possible. In addition, such emissions reductions should be made enforceable, as permit conditions or in the NYCRR.

[224] 2011 NYSDEC, RDSGEIS, Page 6-181.

[225] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 24.

[226] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 24.

[227] See also HCLLC recommendations on LDAR Program in this section of the report.

[228] See also HCLLC recommendations on Reduced Emission Completions in this section of the report.

For example, the Natural Gas STAR Program data shows that it is both technically feasible and economically attractive to use "low-bleed" or "no-bleed pneumatic controllers and plunger lift systems;[229] however, it is not clear whether an operator would be required under the GHG Impacts Mitigation Plan to use this technology, or how NYSDEC would enforce its use if an operator chose not to select it.

NYSDEC should require operators to use Natural Gas STAR Program best management technologies and practices that will optimize emissions reductions.

The RDSGEIS does not make clear whether or how new technologies or practices would be required (e.g. technologies or practices identified by the Natural Gas STAR Program after drillsite construction has been completed). It is not clear if an operator will be required to implement GHG emission controls only at the time of construction, or if there will be an ongoing obligation to implement additional controls as they are identified by the Natural Gas STAR Program and developed.

The plan should include a list of emission controls that will be installed at the time of construction and best management practices, and a process for periodically reviewing new technologies and installing them as new control solutions are developed over time.

Recommendation No. 51: NYSDEC should require a GHG Mitigation Plan that provides for measureable emissions reductions and includes enforceable requirements. The GHG Impacts Mitigation Plan should list all Natural Gas STAR Program best management technologies and practices that have been determined by EPA to be technically and economically feasible, and operators should select and use the emission control(s) that will achieve the greatest emissions reductions.

The GHG Impacts Mitigation Plan should be submitted and approved prior to drillsite construction, GHG controls should be installed at the time of well construction, and NYSDEC should conduct periodic reviews to ensure that GHG Impacts Mitigation Plans include state of the art emission control technologies. Further, the extent of compliance with adopted emission mitigation control plans should be documented throughout the well's potential to emit GHGs.

The GHG Impacts Mitigation Plan requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

Flare and Venting of Gas Emissions:

In 2009, HCLLC recommended that flaring and venting be limited to the lowest level technically feasible and safe. Reducing gas flaring and venting is widely considered best practice. Both federal and state governments have taken steps over the past two decades to enact regulations that limit flaring and venting of natural gas.[230] Initially the motive was to conserve hydrocarbon resources to maximize federal and

[229] Older gas wells stop flowing when liquids (water and condensate) accumulate inside the wellbore creating backpressure on the hydrocarbon formation. This will be a future problem in NYS, as gas wells age. Methane gas is emitted when companies open wells to vent gas to the atmosphere to unload wellbore liquids (water and condensate that accumulate in the bottom of the well) in order to resume gas flow. The industry typically refers to this process as "blowing down the well" or a "well blowdown." Eventually, even a well's own gas pressure becomes insufficient to flow accumulated liquids to the surface and the well is either shut-in as uneconomic, or some form of artificial lift (e.g. plunger lifts) is installed to transport the liquids to the surface.

[230] Global Gas Flaring Reduction Partnership (GGFR), Guidance on Upstream Flaring and Venting Policy and Regulation, Washington D.C., March 2009.

state revenue and gas supply. More recently, focus on GHG, VOC and HAPs emission reduction has prompted additional innovation to further reduce flaring and venting.

Flares may be used during well drilling, completion, and testing to combust hydrocarbon gases that cannot be collected because gas processing and pipeline systems have not been installed. If gas processing equipment and pipeline systems are in place, gas flaring can be avoided in all cases except in the event of equipment malfunction. During the drilling and completion phase of the first well on a well pad, a gas pipeline might not be installed. Gas pipelines are typically not installed until it is confirmed that an economic gas supply has been found. Therefore, gas from the first well is often flared or vented during drilling and completion activities because there is not a pipeline to which it can be routed. The RDSGEIS proposes to require Reduced Emission Completions for all wells where a pipeline is installed, which will reduce the need to flare or vent gas.

During production operations, high pressure gas buildup may require gas venting via a pressure release valve, or gas may need to be routed to a flare during an equipment malfunction. At natural gas facilities, continuous flaring or venting may be associated with the disposal of waste streams[231] and gaseous by-product streams[232] that are uneconomical to conserve. Venting or flaring may also occur during manual or instrumented depressurization events, compressor engine starts, equipment maintenance and inspection, pipeline tie-ins, pigging, sampling activities, and pipeline repair.[233]

Best practices for planned[234] flaring and venting during gas production should limit flaring and venting to the smallest amount possible and only for purposes of for safety. Gas should be collected for sale, and used as fuel unless it is proven to be technically and economically unfeasible.

The 2011 RDSGEIS: The 2011 RDSGEIS limits planned gas flaring to flowback operations for wells where a gas sales line has not been installed which is a significant improvement.[235]

However, when flaring or venting does occur, there is the potential for relatively high short-term VOC and CO emission impacts that need to be considered.[236] The RDSGEIS states that industry only plans to flare for a maximum of three days, and NYSDEC only modeled a 3-day impact; yet, the RDSGEIS states that flaring can occur for up to a month (30 days) in some cases. [237]

> ***<u>A flaring period of 3 days was considered for this analysis</u>*** *for the vertical and horizontal wells respectively although* ***<u>the actual period could be</u>*** *either shorter or* ***<u>longer</u>*** *[emphasis added].*[238]

Modeling needs to represent a reasonable worst case scenario. Because only a three day flaring period was considered in the RDSGEIS modeling, planned flaring should be limited to no more than three days.

[231] For example, acid gas from the gas sweetening process and still-column overheads from glycol dehydrators.

[232] For example: instrument vent gas; stabilizer overheads and process flash gas.

[233] The Global Gas Flaring Reduction partnership (GGFR) and the World Bank, Guidelines on Flare and Vent Measurement, September 2008.

[234] There is a difference between planned flaring and emergency flaring. Emergency flaring is conducted to safely route combustible and potentially toxic (e.g. hydrogen sulfide gas) and in most cases cannot be avoided. Planned flaring can be avoided in most cases.

[235] 2011 NYSDEC, RDSGEIS, Page 5-135.

[236] 2011 NYSDEC, RDSGEIS, Page 6-103.

[237] 2011 NYSDEC, RDSGEIS, Table 5.29 on Page 5-136 shows that well cleanup and testing can take 12 hours to 30 days. Modeling on Page 6-192 only assumes 3 days of flaring.

[238] 2011 NYSDEC, RDSGEIS, Page 6-197.

Alternatively, modeling analysis should be based on the maximum time period that flaring would be allowed.

> **Recommendation No. 52**: Planned flaring should be limited to no more than three days. In all other cases flaring should be limited to safety purposes only. If NYSDEC finds there is an operational necessity to flare an exploration well for more than a three-day period, the SGEIS impact analysis should evaluate the air pollutant impact, particularly the potential for relatively high short-term emission impacts, from longer flaring events, before approving such operations. Flaring restrictions should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

In 2009, HCLLC recommended that NYSDEC should require operators to flare gas as a preferred method over venting. Gas flaring is environmentally preferable over venting because flaring reduces HAP, VOC, and GHG emissions.[239] Proposed revisions to 6 NYCRR § 560.6(c)(28) would require that gas be flared whenever technically feasible instead of vented,[240] which is a significant improvement.

The RDSGEIS limits the amount of flaring and venting that is allowed at a drillsite during any consecutive 12-month period; however, it is unclear how the venting (5 MMscf) or flaring (120 MMscf) thresholds were developed, and such thresholds are not listed in the proposed revisions to the NYCRR.

- *During the flowback phase, the **venting of gas** from each well pad will be limited to a maximum of **5 MMscf** during any consecutive 12-month period. If "sour" gas is encountered with detected hydrogen sulfide emissions, the height at which the gas will be vented will be a minimum of 30 feet (9.1m);*
- *During the flowback phase, **flaring of gas** at each well pad will be limited to a maximum of **120 MMscf** during any consecutive 12-month period [emphasis added].*[241]

> **Recommendation No. 53**: The SGEIS should provide justification for allowing a maximum of 5 MMscf of vented gas and 120 MMscf of flared gas at a drillsite during any consecutive 12-month period. The RDSGEIS does not contain information to show that these limits are equivalent to the lowest levels of venting and flaring that can be achieved through used of best practices, and it is unclear if these rates were used in the modeling assessment. Flaring and venting limits, once justified, should be included in the SGEIS as a mitigation measure, codified in the NYCRR, and should apply to all natural gas operations, not just HVHF operations.

In 2009, HCLLC recommended that NYSDEC require that well operators follow best practices for construction and operation of flares used for safety. The RDSGEIS requires self-igniting flares,[242] which is an improvement; however, the RDSGEIS does not require that:

- Flare pilot blowout risk be minimized by installing a reliable flare system;
- Low/intermittent velocity flare streams have sufficient exit velocity or wind guards;
- A reliable ignition system is used;

[239] Fugitive and Vented methane has 21 times the global warming potential as combusted methane gas. Methanetomarkets.org, epa.gov/gasstar.

[240] 2011 NYSDEC, RDSGEIS, Page 7-117.

[241] 2011 NYSDEC, RDSGEIS, Page 7-108.

[242] 2011 NYSDEC, RDSGEIS, Page 7-117.

- Liquid carry over and entrainment in the gas flare stream is minimized by ensuring a suitable liquid separation system is in place; or
- Combustion efficiency is maximized by proper control and optimization of flare fuel/air/steam flow rates.

Recommendation No. 54: The SGEIS should require flare systems to be designed in a manner that optimizes reliability, safety, and combustion efficiency, including requirements to: minimize the risk of flare pilot blowout by installing a reliable flare system; ensure sufficient exit velocity or provide wind guards for low/intermittent velocity flare streams; ensure use of a reliable ignition system; minimize liquid carry over and entrainment in the gas flare stream by ensuring a suitable liquid separation system is in place; and maximize combustion efficiency by proper control and optimization of flare fuel/air/steam flow rates. Flare design requirements should be included in the SGEIS as a mitigation measure and codified in the NYCRR. These requirements should apply to all natural gas operations, not just HVHF operations.

Reduced Emission Completions:

In 2009, HCLLC recommended the use of Reduced Emission Completions (RECs, also known as “green completions”) to control methane and other greenhouse gas (GHG) emissions following HVHF operations. RECs also reduce nitrogen oxide (NO_x) pollution, which otherwise would be generated by flaring gas wells, and hazardous air pollutants (HAPs) and volatile organic compounds (VOCs) emissions, which otherwise would be released when gas is vented directly into the atmosphere.

EPA estimates that, on average, an REC can capture 7,700 Mcf/well workover for an unconventional gas well. If, for example, 2,000 wells are exempted during the first few years of Marcellus Shale gas development in NYS before pipeline infrastructure is more broadly developed, that could result in 15.3 Bcf (6.2 $MMTCO_2e$) of methane gas vented to the atmosphere.

To put the significance of 15.3 Bcf of methane gas (6.2 $MMTCO_2e$) into perspective, it is equivalent to the GHG emissions from:

- Over 1,100,000 passenger vehicles; or
- The electric use of approximately 700,000 homes for one year; or
- 13,000,000 barrels of oil consumed.[243]

The 2011 RDSGEIS requires RECs where an existing gathering line is located near the well in question, which allows the gas to be collected and routed for sale. While the addition of this requirement represents a substantial improvement that protects air quality and increases the efficiency and productivity of well-sites, NYSDEC should consider expanding its REC requirements to more categories of wells—i.e., wells that are drilled prior to construction of gathering lines. Under the current proposal, a large number of wells could be exempt from the REC requirement, resulting in the flaring or venting of a significant amount of gas that could, instead, be captured for sale.

Furthermore, NYSDEC proposes to postpone making a decision on the number of wells that can be drilled on a pad without the use of RECs until two years after the first HVHF permit is issued.

[243] EPA Greenhouse Gas Equivalencies Calculator, http://www.epa.gov/cleanenergy/energy-resources/calculator.html#results

> *Reduced Emissions Completion (REC) would be required whenever a gathering line is already constructed. In addition,* ***two years after issuance of the first permit for high volume hydraulic fracturing, the Department would evaluate whether the number of wells that can be drilled on a pad without REC should be limited*** *[emphasis added].*[244]

NYSDEC should not defer the implementation of this known best practice, because it could result in the exemption of several thousand wells from this control technology requirement, leading to unmitigated air quality impacts from uncontrolled venting. HCLLC agrees that RECs are not an option for single exploration wells with no offset wells or pipeline infrastructure nearby. In addition, RECs may not be possible if well pressure is too low. Regulations should make exceptions only for these situations in which emission control is truly infeasible. However, RECs should be required in all other circumstances.

Once an exploration well is drilled and hydrocarbons are located, additional drilling and well completion operations on that same drillsite should be coordinated with gas line installation, enabling RECs for all subsequent wells. High-volume hydraulic fracturing can be completed at any time after a well is drilled and gas is found. The well can be temporarily suspended, and the HVHF be conducted once a gas line is in place. In a newly explored area, it may be reasonable to drill an exploration well, and conduct a HVHF treatment to test gas productivity before drilling additional production wells. However, once a commercial source of gas is identified and tested with that initial exploration well, there is no reason to vent or flare gas using the HVHF flowback process and test wells prior to a gas line installation.

In natural gas fields, gas from the first well is often flared or vented during drilling and completion activities, because natural gas pipelines are typically not installed until it is confirmed that an economical gas supply has been found. However, once a pipeline is installed, subsequent wells drilled on that same pad would be in a position to implement REC techniques.

Operators often point to the lack of pipeline infrastructure as a primary reason REC may not be possible. However, there are also alternatives to piping methane, such as using it onsite to generate power, re-injecting it to improve well performance, or providing it to local residents as an affordable power supply. Therefore, RECs do not need to rely solely on the installation of a nearby pipeline.

RECs are technically feasible and economically attractive, and are a commercially available emission control option. Appendix 25 of the RDSGEIS, Reduced Emission Completions Executive Summary, summarizes the economic benefits, making a clear case for requiring this technology on all NYS wells, with few exceptions. RECs provide an immediate revenue stream by routing gas (methane and gas condensates) to a gas sales line that would otherwise be vented into the atmosphere or flared.. Alternatively, captured gas can be used for fuel, offsetting operating costs, or re-injected to improve well performance. Industry has demonstrated that RECs are both an environmental best practice and profitable.

In addition to being economically attractive for the operator, there are a number of other benefits of RECs:

- The collection of potentially explosive gas vapors, rather than venting them to the atmosphere. This improves well site safety, reduces worker exposure to harmful vapors, and limits overall corporate liability.
- The reduction in emissions, noises, odors, and citizen complaints associated with venting or flaring.
- The reduction in disposal costs, as a result of gas and condensate capture and sale.

[244] 2011 NYSDEC, RDSGEIS, Page 1-116.

- The elimination of the need to secure flare permits and provide flaring notifications.[245]
- The reduction of VOCs and HAPs. Unprocessed natural gas contains VOCs and HAPs, along with methane. Flaring, an alternative control device, can reduce VOCs and HAPs. However, flaring generates NO_X and particulate matter (PM), as well as other combustible byproducts. Many areas with significant oil and gas development have challenges achieving ozone and regional haze standards. Therefore, REC technology is a preferred alternative.
- Wells flow back to portable separation units for longer periods than would be allowed with direct venting into the atmosphere or flaring, providing improved well cleanup and enhanced well productivity.
- Fewer wells are drilled as more methane is kept in the system and sent to market, thereby reducing a range of environmental impacts.

While some operators report the voluntary use of RECs, many wells in the United States are still drilled without REC. And, even for companies that have announced the use of RECs, it is not clear how extensively RECs are implemented. Thus, many states have put REC requirements into effect.

The commercial availability of REC equipment has become so widespread that it is now required in several states. For instance, Colorado requires RECs on all oil and gas wells unless they are not technically and economically feasible.[246] Fort Worth, Texas requires RECs.[247] Wyoming has required RECs in the Jonah-Pinedale Anticline Development Area (JPAD) since 2007, and more recently, Wyoming has expanded this requirement to all Concentrated Development Areas (CDAs) of oil and gas in the state.[248]

In 2005, EPA estimated that an average of 7,000 Mcf of natural gas can be recovered during each REC.[249] In 2011, EPA increased the emission recovery estimate and created two distinct categories of wells that are major contributors to methane emissions: Unconventional Gas Wells (7,700 Mcf/well workover) and Low Pressure Gas Well Cleanup (1,400 Mcf/well/year). For each unconventional gas well completion, there is an opportunity to generate about $31,000 in gross revenue, creating a very short payout period if the operator invests in its own equipment.[250]

Investment in REC equipment is extremely profitable, with a conservative average investment cost of $10,000 per REC.[251] The payout occurs quickly if a contractor is hired and the operator only pays a per well REC equipment rental charge. As long as the gas that is captured and sold exceeds the equipment rental charge, the payout is immediate.

Oil and gas operators that have a sufficient number of wells to amortize the cost of REC equipment are finding it more economically attractive to invest in their own technology. Most of the companies that have gone this route report a one- to two-year payout, and substantial profitability thereafter, depending on the gas and condensate recovery rate.[252] For smaller operators, it is possible, and maybe more

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[245] Flaring is not always practicable near populated areas or areas of high forest fire risk.

[246] Colorado Oil and Gas Conservation Commission, Rule § 805(b)(3)

[247] Fort Worth Texas, Ordinance No. 18449-02-2009.

[248] Wyoming Oil and Gas Production Facilities, Chapter 6, Section 2, Permitting Guidance, March 2010.

[249] United States Environmental Protection Agency, Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers, Journal of Petroleum Technology, June 2005.

[250] (7,700 Mcf)($4/Mcf)= $30,800

[251] EPA's Green Completion PRO FACT Sheet No.703 estimates the cost between $1K and $10K; a $10K per completion cost estimate is conservative.

[252] EPA Natural Gas STAR, Green Completions, PRO Fact Sheet No. 703, September 2004.

financially feasible, to rent REC equipment from a contractor. The profitability math is simple. In 2005, the EPA estimated that, on average, 7,000 Mcf/well of natural gas could be captured, yielding a profit of $14K per well, with a payback of less than one year.[253] However, it is important to note that EPA's 2005 profitability calculations were based on lower gas prices ($3/Mcf) than the current market rate ($4+/Mcf). Using the EPA's new 2011 estimate of 7,700 Mcf/well and a gas price of $4/Mcf, each well, on average, has the potential to generate $31,000 in gross revenue. A portion of that revenue stream must be allocated to purchasing or renting the required REC equipment, but unless that cost is greater than $31,000 per well, a REC is a profitable endeavor. Profitability will vary based on the market price for gas and the cost of carrying out the REC.

The EPA has found that RECs are a major contributor to methane reductions on a national scale. In 2008, 50 percent of the EPA's Natural Gas STAR Program's annual total reductions for the oil and gas production sector was attributed to REC s.[254] Therefore, requiring this technology will be very important to NYS' and EPA's GHG emission reduction goals.

Recommendation No. 55: Drilling and well completion operations should be coordinated with gas line installation, enabling RECs for all wells drilled subsequent to the initial exploration well. Alternatively, methane gas should be used onsite to generate power, re-injected to improve well performance, or provided to local residents as an affordable fuel supply. NYSDEC should not defer the decision to implement RECs for two more years. The requirement to use RECs in all practicable situations should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

Wastewater Impoundments:

In 2009, HCLLC pointed out that centralized wastewater impoundments have the potential to be a major source of HAPs—EPA lists facilities that release 10 tons of a single HAP per year as major sources. The 2009 DSGEIS estimated 32.5 tons of methanol[255] per year—more than three times the HAP major source threshold—could be emitted from centralized wastewater impoundments.[256] This large amount of hazardous air pollution was identified as an unmitigated significant impact.

In 2009, HCLLC recommended the use of closed loop collection and tank systems, rather than wastewater impoundments, as a best practice. The 2011 RDSGEIS prohibits the use of wastewater impoundments at the drillsite, requiring closed loop collection and tank systems. This is a substantial improvement. However, the RDSGEIS does not prohibit centralized flowback impoundments at locations

[253] EPA Natural Gas STAR, Cost-Effective Methane Emission Reductions for Small and Mid-Size Natural Gas Producers, Corpus Christi, Texas, November 1, 2005.

[254] 2009 EPA Natural Gas STAR Program Accomplishments, available online at http://www.epa.gov/gasstar/documents/ngstar_accomplishments_2009.pdf. Total sector reductions (2008) = 89.3 Bcf of which 50 percent are the result of RECs (50% of 89.3 Bcf = 45 Bcf).

[255] EPA lists methanol as a hazardous air pollutant, but has not yet classified it with respect to carcinogenicity. The reproductive and developmental effect of methanol on humans is not yet understood. http://www.epa.gov/ttn/atw/hlthef/methanol.html. Testing in rats has yielded skeletal, cardiovascular, urinary system, and central nervous system malformations. American Conference of Governmental Industrial Hygienists (ACGIH), TLVs and BEIs, Threshold Limit Values for Chemical Substances and Physical Agents, Biological Exposure Indices, Cincinnati, OH, 1999. In humans, chronic inhalation or oral exposure may result in headaches, dizziness, giddiness, insomnia, nausea, gastric disturbances, conjunctivitis, blurred vision, and blindness. Neurological damage, specifically permanent motor dysfunction, may also be a result. The Merck Index. An Encyclopedia of Chemicals, Drugs, and Biologicals. 11th ed. Ed. S. Budavari. Merck and Co. Inc., Rahway, NJ. 1989.

[256] 2009 NYSDEC, DSGEIS, Page 6-57.

away from the drillsite and fails to analyze the impacts of such centralization. This represents impermissible segmentation. It is recommended that centralized flowback impoundments be prohibited, however, if this recommendation is not adopted a new draft should be prepared analyzing the potential impacts posed by the reliance on centralized impoundments to store and treat HVHF wastewater and made available for public comment; such a significant analysis cannot be deferred until future site-specific review.

Despite the RDSGEIS's reliance on representations by industry that centralized flowback impoundments are not contemplated at this time, recent experience in Pennsylvania, and other states, reveals that industry's use of centralized flowback impoundments has become common practice. The RDSGEIS either needs to clearly prohibit the use of centralized flowback impoundments in NYS or analyze the potential environmental impacts, including human health impacts, posed by such use and develop ways to avoid or mitigate such impacts.

While industry may not presently intend to build centralized flowback impoundments in NYS, that could change in the future. Based on the use of centralized flowback impoundments as a common industry practice, this is a reasonably foreseeable impact, and unless prohibited is an unmitigated significant impact.

As proposed, there would be no limitations in place for these types of impoundments:

> ***<u>Since September 2009 industry has provided information that</u>***: *(1) simultaneous drilling and completion operations at a single pad would not occur; (2) the maximum number of wells to be drilled at a pad in a year would be four in a 12-month period; and* ***<u>(3) centralized flowback impoundments, which are large volume, lined ponds that function as fluid collection points for multiple wells, are not contemplated</u>*** *[emphasis added]*.[257]

> **Recommendation No. 56**: The use of centralized impoundments to collect waste should be prohibited because these impoundments are a major source of air pollution. This prohibition should be included in the SGEIS as a mitigation measure and codified in the NYCRR.
>
> If centralized flowback impoundments are not prohibited, the potential adverse impacts to human health and the environment must be analyzed fully by NYSDEC. Given that the RDSGEIS includes no analysis whatsoever of the impacts of centralized flowback impoundments, a new draft must be prepared and made available for public comment in order to satisfy the requirements of SEQRA; deferring such analysis for later review would constitute impermissible segmentation. Moreover, mitigation measures to address the potential significant impacts must be included in the SGEIS and codified in the NYCRR.

Gas Dehydrators:

In 2009, HCLLC pointed out that gas dehydration units can emit significant amounts of HAPs and VOCs, and it is best practice to use control devices with gas dehydration units to mitigate HAP and VOC emissions.

[257] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 15-16, and Page 6-111.

Dehydrator units remove water moisture from the gas stream. Dehydrator units typically use triethylene glycol (TEG) to remove the water; the TEG absorbs methane, VOCs, and HAPs. These gases are vented to atmosphere unless pollution controls are installed. Best technology for dehydration units includes the installation of flash-tank separators to recover gas pollutants. Alternatively, pollutants can be routed to a vapor collection/destruction unit, or desiccant dehydrators can be used. Desiccant dehydrators have shown to cost less than flash-tank separators, have lower operating and maintenance costs, and control 99% of HAPs.[258]

The 2011 RDSGEIS requires emissions modeling, using the EPA approved and industry standard model GRI-GlyCalc, and the installation of emission controls for dehydrator units emitting more than one ton per year of benzene. This is an important and substantial improvement.

Appendix 10, Proposed Supplementary Permit Conditions for HVHF, requires:

> *The emissions of benzene at any glycol dehydrator to be used at the well pad will be limited to one ton/year as determined by calculations with the GRI-GlyCalc program. If wet gas is encountered, the dehydrator will have a minimum stack height of 30 feet (9.1m) and will be equipped with a control device to limit the benzene emissions to one ton/year;* [259]

The 2011 RDSGEIS also requires a GHG impacts mitigation plan[260] that includes an evaluation of EPA Natural Gas STAR Best Practices for methane and other GHG emissions. However, it does not make GHG emission controls for gas dehydrators mandatory.

NYSDEC's requirement to control emissions from all dehydrators emitting more than one ton per year of benzene will result in emission control on a number of NYS dehydration units. However, smaller dehydration units that do not fall under this requirement may still have economical methane emission control opportunities.

In 2011, the EPA estimated that approximately 8 Bcf of methane is emitted from gas dehydration systems annually. Most of this methane is emitted from smaller glycol dehydration units currently fall below federal regulatory thresholds for emission control. That methane could instead be captured for sale or use as fuel.[261] While the EPA requires a number of large glycol dehydrators to install emission controls, under the federal Maximum Achievable Control Technology (MACT) standards at 40 CFR Part 63, Subpart HH, small glycol dehydrators are typically exempt. Many small operating glycol dehydrator units do not have flash tank separators, condensers, electric pumps, or vapor recovery installed.

There are four straightforward solutions readily available to control methane emissions from TEG dehydrator units, including: installing a flash tank separator; optimizing the glycol circulation rate; rerouting the skimmer gas; and installing an electric pump to replace the natural gas driven energy exchange pump.

A typical glycol dehydration system includes the following components:

- **Glycol Contactor**: Wet gas enters the glycol contactor. Glycol removes moisture from the gas by the process of physical absorption. Along with removing moisture, the glycol also absorbs methane,

[258] Fernandez, R., Petrusak, R., Robinson, D., Zavadil, D., Cost-Effective Methane Emissions Reductions for Small and Midsize Natural Gas Producers, Journal of Petroleum Technology, June 2005.

[259] 2011 NYSDEC, RDSGEIS, Page 7-108 and 7-109, and Appendix 10, Attachment A.

[260] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 24.

[261] USEPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks; (1990-2009), April 15, 2011.

VOCs, and HAPs. Dry gas exits the glycol contactor absorption column and is either routed to a pipeline or a gas plant.

The glycol contactor unit plays the primary role in dehydrating gas to pipeline specifications; the rest of the glycol dehydration system is required to convert the now moisture rich glycol back into a lean product that can be re-used to dehydrate more incoming gas. Therefore, the next step in the process is to route the moisture rich glycol to "regenerator" and "reboiler" units.

- **Glycol Regenerator & Reboiler:** Glycol loaded with moisture, methane, VOCs, and HAPs ("rich glycol") exits the bottom of the glycol contactor unit and is routed to the glycol regenerator and reboiler units, where the absorbed components are removed and "lean" glycol is created. If emission controls are not installed, methane, VOCs, HAPs, and water are boiled off and vented to atmosphere from the regenerator and reboiler units.

  One way to limit the amount of methane, VOCs, and HAPs emitted to the atmosphere from the regenerator and reboiler units is to install a flash tank separator.

- **Flash Tank Separator:** The installation of a flash tank separator between the glycol contactor and the glycol regenerator/reboiler units creates a pressure drop in the system, allowing methane and some VOCs and HAPs to flash out of (separate from) the glycol. The amount of pressure drop that can be created is a function of the fuel gas system pressure or compressor suction pressure, because methane gas flashed-off at the flash tank separator is then sent to be used as fuel in the TEG reboiler or compressor engine. Simply put, the pressure can only be dropped to a pressure that still exceeds the fuel gas pressure, allowing the collected methane gas to flow into the fuel system. Flash tank separators typically recover 90 percent of the total methane and approximately 10 to 40 percent of the total VOCs that would otherwise be vented to atmosphere. Methane emissions can also be controlled by taking the simple step of adjusting the rate that glycol is circulated in the system.

  In 2005, the EPA estimated that the installation of a flash tank separator, on average, resulted in 10 Mcfd (3,650 Mcf/yr) of methane gas captured for sale or use as fuel for each TEG dehydrator (typically a 90 percent reduction in methane emissions). And in 2009, the EPA reported that flash tank separators are installed on ***only***: 15 percent of the dehydration units processing less than 1 MMcfd; 40 percent of units processing 1 to 5 MMcfd; and between 65 and 70 percent of units processing more than 5 MMcfd.[262] Therefore, an emission control target still exists, especially for small dehydration units.

  The installation of a flash tank separator also improves the efficiency of downstream components (e.g. condensers) and reduces fuel costs by providing a fuel source to the TEG reboiler or compressor engine.[263]

- **Glycol Recirculation Pump**: Methane emissions are directly proportional to the glycol circulation rate. Circulating glycol at a rate that exceeds the operational need for removing water content from gas unnecessarily increases methane emissions. Glycol circulation rates are typically set at the maximum to account for peak throughput. Gas pressure and flow rate decline over time, requiring the glycol circulation rate to be adjusted to meet operational need. Optimizing the glycol circulation merely requires an engineering assessment and a field operating adjustment. If the glycol dehydration unit includes a condenser, methane emissions can be collected and used for fuel or destroyed, rather than being vented to atmosphere.

  In 2005, the EPA estimated that optimizing the glycol circulation rate could result in a wide range of methane capture from 1 to 100Mcfd (18,250 Mcf/yr using a median estimate of 50 Mcfd). [264]

[262] USEPA Natural Gas STAR, Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators, 2009.

[263] USEPA Natural Gas STAR, Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators, 2009.

- **Condensers**: Some glycol reboilers have condensers to recover natural gas liquids and reduce VOCs and HAPs. However, condensers do not capture methane (because it is a non-condensable gas); therefore, the addition of a condenser does not reduce methane emissions. When condensers are installed, methane gas is typically vented to atmosphere. Alternatively, this methane gas (called "skimmer gas") can be routed to the reboiler firebox or other low-pressure fuel gas systems.[265] In 2005, the EPA estimated that rerouting glycol skimmer gas could result in an average methane capture of 21 Mcfd (7,665 Mcf/yr). [266]

- **Electric Pump vs. Energy-Exchange Pumps:** Historically, gas-assisted glycol pumps have been used. Where there is an electric supply, the gas-assisted glycol pumps can be replaced with an electric pump. Gas-assisted pumps are driven by the expansion of the high-pressure gas entrained in the rich glycol that leaves the contactor, supplemented by the addition of untreated high-pressure wet (methane rich) natural gas. The high-pressure gas drives pneumatic pumps. Much like pneumatically operated valves, pneumatically operated pumps vent methane.

  In 2007, the EPA estimated that between 360 and 36,000 Mcf/yr in methane emission reductions could be achieved by installing an electric pump to replace the natural gas driven glycol energy exchange pump; the wide range in methane emission reductions is a function of the large variation in equipment sizes.[267]

In 2007, EPA estimated the total potential emission reductions at any given glycol dehydration unit is a function of how many emission control solutions are installed. The total may range from 3,700-35,000 Mcf/year ($14.8K-$140K worth of gas leakage). In 2011, EPA estimated 38,000 Mcf/year ($152K).[268] Therefore, controlling methane emissions and other GHG emissions from dehydration units is good business.

However, despite the clear environmental and financial benefits, not all members of the oil and gas industry voluntarily invest in methane control options. Therefore, it is recommended that NYSDEC require operators to evaluate the technical and economic feasibility of installing methane emission controls on gas dehydrators; installation should be mandatory unless an infeasibility determination is made.

Recommendation No. 57: Natural gas operators should be required to evaluate the technical and economic feasibility of installing methane emission controls on gas dehydrators; installation should be mandatory unless an infeasibility determination is made. This requirement should be included in the SGEIS as a mitigation measure and codified in the NYCRR. This requirement should apply to all natural gas operations, not just HVHF operations.

[264] The wide range in methane capture opportunity is a function of the dehydrator size, and how efficiently the operator previously optimized the glycol circulation rate.

[265] USEPA Natural Gas STAR, Reroute Glycol Skimmer Gas, PRO Fact Sheet No. 201, 2004.

[266] EPA Natural Gas STAR, Cost-Effective Methane Emission Reductions for Small and Mid-Size Natural Gas Producers, Corpus Christi, Texas, November 1, 2005.

[267] EPA Natural Gas STAR, Natural Gas Dehydration, Producers Technology Transfer Workshop, Durango Colorado, September 13, 2007.

[268] USEPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks; (1990-2009), April 15, 2011.

Diesel Engine Emission Control:

In 2009 AKRF recommended that diesel engines should be Tier 2 or higher. AKRF pointed out that "Tier 0" engines could be used, unless NYSDEC limited engines by certification type. Uncertified engines have extremely high emission rates for criteria pollutants such as particulate matter.

Additionally, AKRF recommended that diesel particle filters be installed on diesel engines to reduce particulate matter that has shown to aggravate respiratory systems and is known to be carcinogenic. More specifically AKRF recommended that all engines with a power output of 50 horsepower or greater be equipped with a diesel particle filter, either by the original engine manufacturer or by retrofit.

The 2011 RDSGEIS, Appendix 10 Proposed Supplementary Permit Conditions for HVHF, addressed most of AKRF's recommendations, by prohibiting Tier 0 engines, requiring Tier 2 engines in most cases, and requiring both Tier 1 and Tier 2 engines to install emission controls. NYSDEC proposes that:

- ***No uncertified (i.e., EPA Tier 0) drilling or hydraulic fracturing engines*** *will be used for any activity at the well sites;*
- ***The drilling engines and drilling air compressors will be limited to EPA Tier 2 or newer equipment. If Tier 1 drilling equipment is to be used, these will be equipped with both particulate traps (CRDPF [Continuously Regenerating Diesel Particulate Filters]) and SCR [Selective Catalytic Reduction] controls****. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from the control requirements or proposes alternate mitigation and/or control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence; and*
- ***The completion equipment engines will be limited to EPA Tier 2 or newer equipment. Particulate traps will be required for all Tier 2 engines****. SCR control will be required on all completion equipment engines regardless of the emission Tier. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from this requirement or proposes mitigation and/or alternate control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence [emphasis added].*[269]

NYSDEC estimates that 25% of the engines may be Tier 1 engines, and to ensure compliance with National Ambient Air Quality Standards (NAAQS) it requires the engine to be equipped with both CRDPFs and Selective Catalytic Reduction controls.

While NYSDEC has proposed a number of improvements for diesel engine emission control, the RDSGEIS did not assess whether Tier 1 engines could be eliminated altogether.

Recommendation No. 58: The SGEIS should examine whether it is possible to eliminate Tier 1 engine use. Further examination of AKRF's recommendation to prohibit Tier 1 engine use is warranted.

[269] 2011 NYSDEC, RDSGEIS, Page 7-108 and 7-109 and Appendix 10, Attachment A, Condition 9-11.

Leak Detection & Repair Program:

In 2009 HCLLC recommended that NYSDEC require Leak Detection and Repair (LDAR) programs including acoustic detectors and infrared technology to detect odorless and colorless leaks. Unmitigated gas leaks pose a risk of fire and explosion, and contribute to GHG, VOC, and HAP emissions, that could otherwise be avoided by routine detection and repair programs.

Methane gas leaks can occur from numerous locations at gas facilities—valves, drains, pumps, threaded and flanged connections, pressure relief devices, open-ended valves and lines, and sample points—as gas moves through equipment under pressure. These leaks are called "fugitive emissions."

Fugitive emissions from equipment leaks are unintentional losses of methane gas that may occur due to normal wear and tear, improper or incomplete assembly of components, inadequate material specifications, manufacturing defects, damage during installation or use, corrosion, or fouling.[270]

Because methane is a colorless, odorless gas, leaks often go unnoticed. Historically, leak checks were only performed on equipment components when they were first installed, using a soap bubble test or hand held sensor, to ensure the installation was leak tight. After installation leaks were not typically monitored or repaired unless they became a significant safety hazard. For example, a significant gas leak would be repaired if area, building, or employee monitors set off alarms or if olfactory, audible, or visual indicators observed by facility employees identified the leak. Under these circumstances, the leaks had usually become an obvious safety concern. As a result, methane leaks at outdoor facilities and unmanned facilities often went undetected for long periods of time.

Fugitive emission control is a two-part process that includes: (1) a monitoring program to identify leaks and (2) a repair program to fix the leak. Monitoring program type and frequency is a function of the type of component, and how the component is put to use. In most cases, monitoring programs can be intermittently scheduled at a certain frequency (e.g. monthly or quarterly) to identify leaking equipment. However, permanent leak sensors may be required to detect chronic leakers.[271]

There are many different monitoring tools that can be used to identify leaks, including electronic gas detectors, acoustic detectors, ultrasound detectors, flame ionization detectors, calibrated bagging, high volume sampler, end-of-pipe flow measurement, and infrared leak detection. Once leaks are identified, the operator can evaluate what is causing the leak and develop a replacement or repair program to mitigate the leak.

For example, a hand held infrared camera can be used as a screening tool to detect emissions that are not visible to the naked eye. An infrared camera produces images of gas leaks in real-time. [272] It is capable of identifying methane leaks, but cannot quantify the amount of the leak. Infrared cameras produce photos that show methane gas leaks.

Once a leak is identified, and a more quantitative leak flow rate determination is needed, other measurement devices such as Hi-Flow Samplers, Vent-Bag Methods, and Anemometers may be used.[273] Hi-Flow Samplers capture the entire leak, measuring the leak rate directly for leaks up to 10 cubic feet per

[270] USEPA, Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry, 2009.

[271] Squarek, J. (Canadian Association of Petroleum Producers), Layer, M. (Environment Canada) and Picard, D. (Clearstone Engineering Ltd.), Development of a Best Management Practice in Canada for Controlling Fugitive Emissions at Upstream Oil and Gas Facilities, 2005.

[272] Snider, P., Advanced Well Completion Technology to Reduce Methane Emissions and Use of Infared Cameras for Leak Detection, Global Forum on Flaring and Venting Reduction and Natural Gas Utilisation, 2008.

[273] Heath, M.W., Leak Detection and Quantification of Fugitive Methane Emissions at Natural Gas Facilities, 2009.

minute (cfm), providing leak flow rate and concentration data. [274] Toxic Vapor Analyzers and acoustic leak detection systems are other methods to identify methane leaks.[275]

Fugitive emissions management is an ongoing commitment, not a one-time initiative. The potential for fugitive equipment leaks will increase as facilities age. Successful fugitive emission control plans require trained personnel, emissions testing equipment, and performance tracking systems.

In 2009, the EPA examined the profitability of repairing equipment leaks at oil and gas facilities and found that leak repair is not only an important air pollution control and safety measure, but also is a profitable investment.[276] EPA reports that fugitive emissions control provides numerous benefits including: reduced maintenance costs and downtime, improved process efficiency, a safer work environment, a cleaner environment, and resource conservation.

The 2011 RDSGEIS acknowledges the potential impact of gas leaks, and requires a Leak Detection and Repair Program to be included in the operator's GHG Mitigation Plan.

> *Because the production phase is the greatest contributor of GHGs and in an effort to mitigate VOC and methane leaks during this phase, the* ***Department proposes to require, via permit condition and/or regulation, a Leak Detection and Repair Program would include as part of the operator's greenhouse gas emissions impacts mitigation plan which is required for any well subject to permit issuance under the SGEIS*** *[emphasis added].*[277]

The 2011 RDSGEIS specifies the minimum requirements for a Leak Detection and Repair Program.

> ***The Leak Detection and Repair Program within the greenhouse gas emissions impacts mitigation plan would contain the following minimum requirements***.
>
> - *There would be an ongoing site inspection for readily detected leaks by sight and sound whenever company personnel or other personnel under the direction of the company are on site. Anytime a leak is detected by sight or sound, an attempt at repair should be made. If the leak is associated with mandated worker safety concerns, it should be so noted in follow-up reports;*
> - *Within 30 days of a well being placed into production and at least annually thereafter, all wellhead and production equipment, surface lines and metering devices at each well and/or well pad including and from the wellhead leading up to the onsite separator's outlet would be inspected for VOC, methane and other gaseous or liquid leaks. Leak detection would be conducted by visible and audible inspection and through the use of at least one of the following: 1) electronic instrument such as a forward looking infrared camera, 2) toxic vapor analyzer, 3) organic vapor analyzer, or 4) other instrument approved by the department;*
> - *All components noted above that are possible sources of leaks would be included in the inspection and repair program. These components include but are not limited to: line heaters, separators, dehydrators, meters, instruments, pressure relief valves,*

[274] http://www.heathus.com/_hc/index.cfm/about-us/vision

[275] Methane to Markets, Reducing Methane Emissions through Directed Inspection and Maintenance (DI&M), Oil & Gas Subcommittee Technology Transfer Workshop, 2009.

[276] Methane to Markets, Reducing Methane Emissions Through Directed Inspection and Maintenance (DI&M), Oil & Gas Subcommittee Technology Transfer Workshop, 2009.

[277] 2011 NYSDEC, RDSGEIS, Page 7-114 .

vents, connectors, flanges, open-ended lines, pumps and valves from and including the wellhead up to the onsite separator's outlet;

- *For each detected leak, if practical and safe an initial attempt at repair would be made at the time of the inspection, however, any leak that is not able to be repaired during the inspection may be repaired at any time up to 15 days from the date of detection provided it does not pose a threat to on-site personnel or public safety. All leaking components which cannot be repaired at detection would be identified for such repair by tagging. All repaired components would be re-inspected within 15 days from the date of the initial repair and/or re-repair to confirm, using one of the approved leak detection instruments, the adequacy of the repair and to check for leaks. The department may extend the period allowed for the repair(s) based on site-specific circumstances or it may require early well or well pad shutdown to make the repair(s) or other appropriate action based on the number and severity of tagged leaks awaiting repair; and*
- *Site inspection records would be maintained for a minimum period of 5 years. These records would include the date and location of the inspection, identification of each leaking component, the date of the initial attempt at repair, the date(s) and result(s) of any re-inspection and the date of the successful repair if different from initial attempt [emphasis added].*[278]

The RDSGEIS proposal to require an LDAR Program is a substantial improvement; however, a few changes to the proposed program are recommended:

- An LDAR inspection should be conducted at well/drillsite start-up, not 30 days after. It is best practice to construct and install equipment and test for leaks prior to operation. Equipment should not be operated for 30 days without completing this minimum standard of care.
- Quarterly testing with an infrared camera (as a screening method) should be required, instead of annual testing, as a minimum standard. If the infrared camera screening indicates a leak, the leak location, if clearly pin pointed, should be repaired. Or additional testing should be conducted using more sophisticated tools (described above) to pin-point the leak location, followed by a repair.
- Testing should include all equipment located on the drillsite. As proposed, the RSGEIS suggests the LDAR Program end at the separator's outlet. Equipment will be located downstream of the separator outlet, and prior to the connection the gas transit line that could potentially leak gas. Therefore, it is recommended that the LDAR Program be implemented for all equipment on the drillsite up to and including the gas meter outlet which is connected to the pipeline inlet.

Recommendation No. 59: The proposed LDAR Program should be revised to require: a drillsite LDAR inspection at start-up; quarterly testing with an infrared camera with additional follow-up testing and repair if a leak is indicated; testing of all equipment located on the drillsite up to and including the gas meter outlet which is connected to the pipeline inlet. These requirements should be included in the SGEIS as mitigation measures and codified in the NYCRR, and be required for all natural gas operations, not just HVHF operations.

[278] 2011 NYSDEC, RDSGEIS, Page 7-115 and 7-116.

Cleaner Power and Fuel Supply Options:

In 2009, HCLLC and AKRF recommended that the SGEIS evaluate the use of cleaner engines and fuels.

In suburban and urban areas of NYS, where a connection to the electric power grid is available, electric engines should be used in lieu of diesel wherever practicable, thus eliminating local diesel exhaust. This alternative would be particularly beneficial where operations are planned near sensitive receptors and in areas that already suffer from high air pollutant loading. Electric engines have the added benefit of quieter operation and less noise impact in urban and suburban settings.

In rural areas, where high-line power is not readily available, an operator should be required to evaluate whether there is a natural gas supply that could be used as fuel. Natural gas fired engines produce less air pollution that diesel engines. A natural gas supply should be available for all wells drilled on a multi-well drillsite, except the first well. Once the first well is drilled using diesel, subsequent wells can be drilled using the natural gas produced by that well to generate power. Smaller temporary gas processing units are available to process wellhead gas to the quality required for equipment use. The use of dual fuel engines would enable switching from diesel to natural gas once it is available.

The use of electric and natural gas engines would result in reduced local pollutant emissions and overall GHG emissions (both grid power and natural gas have a lower carbon footprint than diesel) and generally would have associated cost savings given the reduced fuel transportation and storage needs (e.g. double-wall tanks) and the reduced risk of tank leakage and cleanup associated with the use of fuel gas produced on-site or electric power.

The 2011 RDSGEIS: The 2011 RDSGEIS did not examine cleaner power and fuel supply options. The RDSGEIS only briefly mentioned that electric engines and cleaner fuel options were recommended[279] but disregarded the recommendations as "unlikely to be practically implemented to any extent" due to the remote nature of the drillsites. This analysis is incomplete and fails to consider viable alternatives for mitigating air pollution.

Foremost, electric power is available in all suburban and urban areas of NYS, and is currently located in many rural areas as well to supply power to homes, farms and businesses.

Secondly, the use of natural gas-fired engines on a multi-well drillsite is a commonly used mitigation measure. While diesel engines are often used as the prime mover of power supply for rotary well drilling, natural gas or dual fuel (diesel/gas) engines are available to take advantage of cleaner fuel supplies.[280] EnCana, a gas producer, reports that natural gas-fired rigs reduce air pollution by 90% compared to diesel fired rigs.[281] Power can also be supplied to the drilling rig by a natural gas-powered reciprocating turbine that can generate electricity on site.

[279] 2011 NYSDEC, RDSGEIS, Page 6-144.

[280] www.naturalgas.org.

[281] EnCana 2005 Annual Report.

Recommendation No. 60: In suburban and urban areas of NYS, where a connection to the electric power grid is available, electric engines should be used in lieu of diesel wherever practicable, eliminating the local diesel exhaust from those engines. In rural areas, where high-line power is not readily available, an operator should be required to evaluate whether there is a natural gas supply that could be used as fuel; if so, use of the natural gas supply should be mandatory to the extent practicable. Cleaner power and fuel selection requirements should be included in the SGEIS as a mitigation measure and codified in the NYCRR. These requirements should apply to all natural gas operations, not just HVHF operations.

18. Surface Setbacks from Sensitive Receptors

Background: The 2009 DSGEIS did not propose sufficient safety or quality-of-life surface setbacks from sensitive human and environment resource receptors. This problem persists in the 2011 RDSGEIS. Noise, traffic, odor, air, and water pollution impacts to sensitive receptors will be significant if the small setbacks proposed in the RDSGEIS are adopted.

Surface setbacks should be increased to mitigate significant impacts and to create a safe environment for the affected public. For example:

- Blowouts can eject drilling mud, hydrocarbons, and/or formation water from a well onto adjacent waters and lands. Depending on reservoir pressure, blowout circumstances, and wind speed, these pollutants can be distributed hundreds to thousands of feet away from a well. These pollutants can then be further transported in the subsurface or on the surface, creating a large area of contamination in a very short amount of time.
- Chemicals, fuels, and explosive charges (e.g. perforating guns) may be located at the drillsite and may pose hazards to the public, in addition to the flammable, explosive, and hazardous gases (e.g. hydrogen sulfide gas, benzene) that are produced from the well and associated equipment.
- The potential radius of impact for explosions, fire, and other industrial hazards should be considered. For example, the city of Forth Worth, Texas uses the International Fire Code as the basis for its minimum 600' setback from Barnett shale gas drilling operations. [282] Whereas, NYCRR only provides for a 100' setback from a home. 6 NYCRR § 553.2.
- High pressure hose leaks can spray industrial fluids off the drilling pad and onto surrounding properties or waters. The radius of contamination will depend on system pressure, shut-down reaction timing, wind speed, and other factors.

For example, in September 2009, 1,300 gallons of well chemicals were leaked during a hydraulic fracture treatment at the Cabot Heitsman 4H well located in Susquehanna Country, Pennsylvania, and flowed into the nearby Steven's Creek located more than 100 feet away, despite protections in place under the operator's required Pennsylvania PPC plan.[283]

Recommendation No. 61: The SGEIS should provide scientific and technical justification for each setback distance proposed to demonstrate how that distance is protective of the nearby sensitive receptor. A hazard identification analysis should be completed to assess the safe distance from human and sensitive environmental receptors to proposed shale gas drilling and HVHF operations. The analysis should assess blowout radius, spill trajectory, explosion hazards, other industrial hazards, fire code compliance, human health, agricultural health, and quality-of-life factors. Improved setbacks as a result of this analysis should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

While statewide minimum setbacks to protect human health, provide safe buffers, and protect the environment should be established, both the RDSGEIS and NYCRR should include a provision to allow local communities to establish more protective setbacks than statewide regulations to address unique and site-specific local concerns and community characteristics.

[282] Fort Worth Gas Drilling Regulations Presentation, Barnett Shale EXPO, March 11, 2009.

[283] Cabot Oil & Gas Corporation, Engineering Study, for submittal to PADEP, In Response to Order dated September 24, 2009, prepared by URS Corporation for Cabot, October 9, 2009.

Recommendation No. 62: The SGEIS and NYCRR should allow local zoning authorities to establish more protective setbacks than statewide regulations to address unique and site-specific local concerns and community characteristics. The ability to improve local setbacks should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

The 2011 RDSGEIS: The 2011 RDSGEIS proposes additional setbacks from aquifers, wells, and water bodies for HVHF operations, but does not establish additional setbacks from homes or public buildings.

NYSDEC does not provide scientific or technical justification in the RDSGEIS for the setback distances it has selected. Setbacks ranging from 150' to 2,000' are included in the RDSGEIS without justification for how or why those particular distances were selected or determined to be adequate to protect water resources.

The 2011 RDSGEIS proposes the following setbacks:

- **500' setback from primary and principal aquifers**. However, for principal aquifers, drilling and HVHF operations can occur within that 500' buffer with additional review, and for both primary and principal aquifers the setback distance will be reconsidered in two years in a yet to be determined process.

  Well pads for high-volume hydraulic fracturing would be prohibited within 500 feet of primary aquifers (subject to reconsideration 2 years after issuance of the first permit for high-volume hydraulic fracturing).[284]

  For at least two years from issuance of the first permit for high-volume hydraulic fracturing, proposals for high-volume hydraulic fracturing at any well pad within 500 feet of principal aquifers, would require (1) site-specific SEQRA determinations of significance and (2) individual State Pollutant Discharge Elimination System (SPDES) permits for stormwater discharges. The Department would re-evaluate the necessity of this approach after two years of experience issuing permits in areas outside of the 500-foot boundary.[285]

- **2,000' setback from a public water supply**, unless a shale gas well is located within 1000' of a subsurface water supply designated by the New York City Department of Environmental Protection (NYCDEP). However, these setbacks will be reconsidered in three years in a yet to be determined process.

  The Department will not issue well permits for high-volume hydraulic fracturing at the following locations…any proposed well pad within 2,000 feet of public water supply wells, river or stream intakes and reservoirs (subject to reconsideration 3 years after issuance of the first permit for high-volume hydraulic fracturing).[286]

  The Department proposes that site-specific environmental assessments and SEQRA determinations of significance be required for … any proposed well location determined by NYCDEP to be within 1,000 feet of its subsurface water supply infrastructure.[287]

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[284] 2011 NYSDEC, RDSGEIS, Page 1-17.
[285] 2011 NYSDEC, RDSGEIS, Page 1-18.
[286] 2011 NYSDEC, RDSGEIS, Page 3-15.
[286] 2011 NYSDEC, RDSGEIS, Page 3-16.
[287] 2011 NYSDEC, RDSGEIS, Page 3-15.

Recommendation No. 63: The process for revising the 500' setback from primary and principal aquifers and the 2,000' setback from a public water supply in two and three years, respectfully, is unclear. NYSDEC should clarify the review process, including an explanation of its plans for public review and comment. NYSDEC should revise its regulations at 6 NYCRR § 617.4(b) to provide that the siting of any oil or gas well within 500' of a primary aquifer or within 2,000 of a public water supply is a Type I action.

- **500' setback from a private water well**.

> *The Department will not issue well permits for high-volume hydraulic fracturing at the following locations…any proposed well pad within 500 feet of private drinking water wells or domestic uses springs, unless waived by the owner.*[288]

The RDSGEIS provides no rationale as to why a public water supply would be afforded a 2,000' setback, while a private water well would only be afforded at 500' setback.

Recommendation No. 64: The SGEIS should examine whether waivers to the 500' private water well setback comport with federal law and the requirement to protect Underground Sources of Drinking Water (USDWs). The SGEIS should provide technical justification for any reduction in this setback, and should not allow a private well owner to reduce the setback such that it poses a risk to its water supply, as well as other user in the area. Private land owners should not be allowed to waive setbacks from private water wells and adversely affect the water quality of neighboring wells.

- **150' setback from a stream, storm drain, lake, or pond**.

> *Based on the above information and mitigating factors, the Department proposes that site specific SEQRA review be required for projects involving any proposed well pad where the closest edge is located within 150 feet of a perennial or intermittent stream, storm drain, lake or pond.*[289]

The 150' setback language conflicts with the 2,000' setback language above, because it allows a closer setback from lakes, rivers and streams than from a public water supply. It is not clear which lakes, rivers, and streams would be protected by the 150' setback, and which would be protected by a 2,000' setback.

On October 3, 2011 Pennsylvania Governor Corbett announced plans to implement the Marcellus Shale Advisory Commission recommendation to increase the setback distance for wells near streams, rivers, ponds and other bodies of water to at least 300'.[290] An increased set back to at least 300' should also be considered by NYS.

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[288] 2011 NYSDEC, RDSGEIS, Page 7-76.

[289] 2011 NYSDEC, RDSGEIS, Page 7-76.

[290] Pennsylvania Office of the Governor, News Release, Governor Corbett Announces Plans to Implement Key Recommendations of Marcellus Shale Advisory Commission, October 3, 2011.

Recommendation No. 65: The conflicting language between the 150' setback requirement and 2,000' setback requirement for lakes, rivers, and streams needs to be resolved in both the SGEIS and the NYCRR. As drafted, neither the RDSGEIS nor the NYCRR are clear which lakes, rivers, and streams would be protected by the 150' setback, and which would be protected by a 2,000' setback. NYSDEC should indicate whether it intends to apply the 150' setback only to surface water resources that are not actual or potential public drinking water supplies. NYSDEC should also explain whether the 150' set back is sufficient to protect those water resources, or whether this setback should be increased. Improved setbacks as a result of this analysis should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

- **4,000' setback from NYC and Syracuse watersheds**.

  Accordingly, the Department recommends that regulations be adopted to prohibit high-volume hydraulic fracturing in both the NYC and Skaneateles Lake watersheds, as well as in a 4,000 -foot buffer area surrounding these watersheds, to provide an adequate margin of safety from the full range of operations related to high-volume hydraulic fracturing that extend away from the well pad. The Department also is presenting this proposal based on its consistency with the principles of source water protection and the "multi-barrier" approach to systematically assuring drinking water quality.[291]

Recommendation No. 66: The 4,000' setback from NYC and Syracuse watersheds should be added to the proposed regulatory revisions for operations associated with HVHF at 6 NYCRR § 560.4. The SGEIS and NYCRR should also clarify if activities associated with HVHF drilling and completions will be prohibited underneath the watershed as well as on the surface.

NYSDEC has not provided engineering or scientific justification for the setback distances it has selected, other than a brief assessment of the setbacks that are allowed in other states. NYSDEC ultimately selected setbacks that are not as protective as those identified by the agency's consultants. For example, the RDSGEIS, states:

> *The required setbacks from surface water supplies in other states reviewed by Alpha vary between 100 and 350 feet.*[292]

NYSDEC's consultants collected information that shows a more protective 350' setback is in use in other states; however, NYSDEC concludes that only a 150' setback will be required. This is less than half the distance of the most protective standard found by NYSDEC's consultants, and the 150' setback can be further reduced at NYSDEC's discretion based on a site-specific SEQRA review:

> *Based on the above information and mitigating factors, the Department proposes that site specific SEQRA review be required for projects involving any proposed well pad where the closest edge is located within 150 feet of a perennial or intermittent stream, storm drain, lake or pond.* [293]

[291] 2011 NYSDEC, RDSGEIS, Page 7-56.
[292] 2011 NYSDEC, RDSGEIS, Page 7-76.
[293] 2011 NYSDEC, RDSGEIS, Page 7-76.

Of note, the RDSGEIS does not address setbacks from homes or public buildings. The RDSGEIS merely requires the operator to document the distance from the proposed drilling and HVHF operations to "…any residences, occupied structures or places of assembly within 1,320 feet."[294] However, no new setback is established for homes or public buildings, other than required by current regulations.

NYCRR Proposed Revisions: The new setbacks proposed in the RDSGEIS are codified in regulation at 6 NYCRR §560.4. These setbacks would apply only to wells that undergo HVHF. NYSDEC does not explain why these setbacks would not apply to all oil and gas well drilling in NYS, despite the fact that 6 NYCRR § 553.2 (Well Surface Restrictions) applies to all NYS oil and gas wells. NYSDEC has not justified its limiting of new setback increases to HVHF wells only.

Recommendation No. 67: The setback increases proposed in the RDSGEIS should apply to all oil and gas drilling in NYS and should be codified at 6 NYCRR § 553.2.

The existing NYCRR allows drilling, HVHF operations, and production equipment to be located within 100' from an inhabited private dwelling and within 150' from a public building or area that may be used as a place of "resort, assembly, education, entertainment, lodging, trade, manufacture, repair, storage, traffic or occupancy by the public." The existing NYCRR also allows drilling, HVHF operations, and production equipment to be located within 50' from a public stream, river, or other body of water. There is no required setback from buildings or structures used for agriculture. 6 NYCRR § 553.2.

The proposed revisions to the NYCRR include 500' setbacks from primary aquifers, 2,000' setbacks from public water supplies, and 500' setbacks from private wells. Proposed 6 NYCRR § 560.4. However, these setbacks apply only to wells that undergo HVHF, and do not apply to all wells that undergo hydraulic fracturing operations in NYS.

NYSDEC's setback analysis does not take into account that directional drilling technology enables wells to be drilled to a bottom-hole location at 3-5 miles[295] away from a wellhead. In directional drilling, it is now common for the horizontal displacement of the bottom hole location to be several times the total vertical depth (TVD) of the well. For example, a well with a vertical depth of 5,000' could have a bottom hole horizontal displacement of 10,000-15,000' from the drill site, or more. A well with a vertical depth of 7,000' could have a bottom hole horizontal displacement of 14,000-21,000' from the drill site, or more. For example, in 1997, BP drilled a well to approximately 5,300' achieving a 33,182' horizontal displacement, meaning the wellhead was located over 6 miles away from the hydrocarbon target.[296] In 1997, a 6-mile horizontal displacement was a great feat; now, extended reach drilling (ERD) is commonplace in the industry, and wells are routinely drilled to hydrocarbon targets miles away from the wellhead.

Given the flexibility afforded by the fact that 640-acre spacing units may vary in shape, from square to rectangular, and that surface drillsites need not be located over the spacing unit, well operators utilizing directional drilling technology have a greater ability to select surface drillsite locations that optimize distance from sensitive public and private resources.

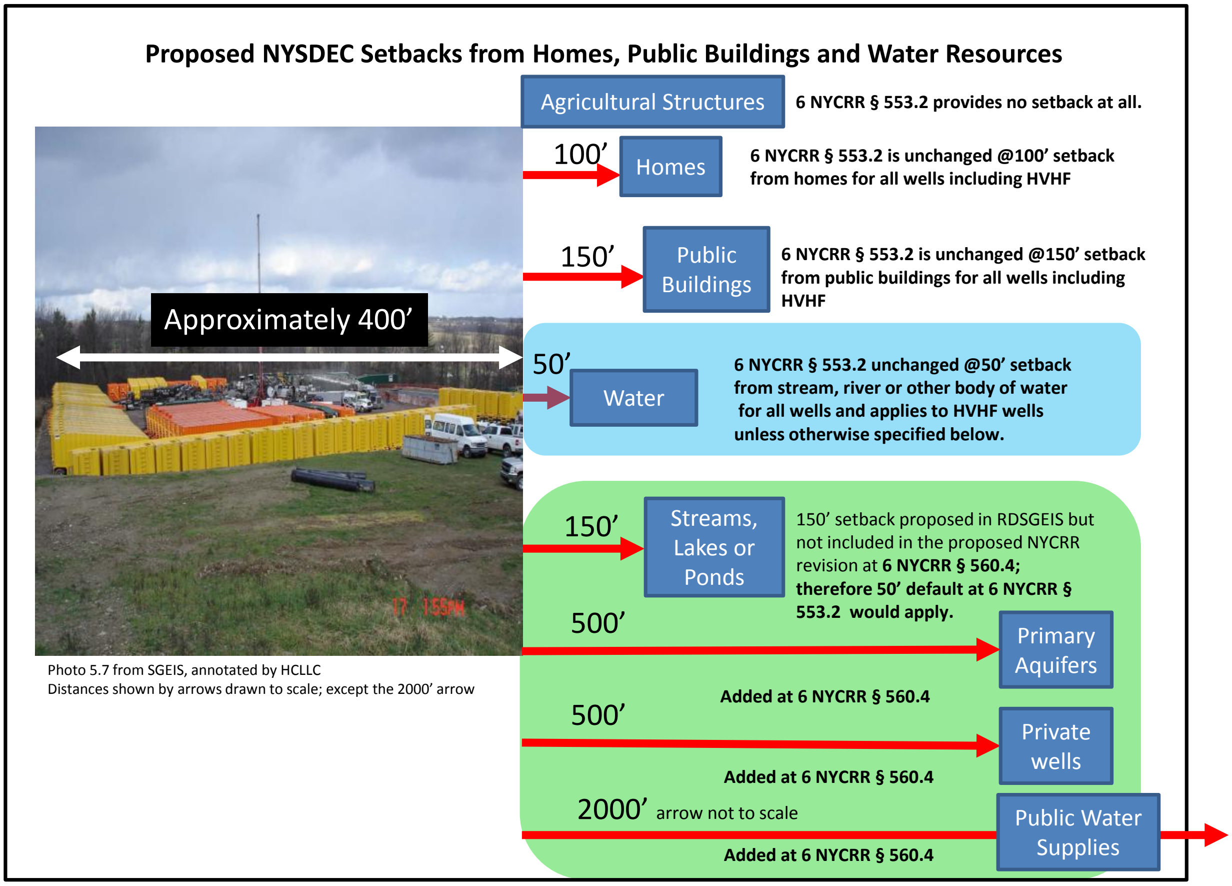
As shown in the figure below, the setbacks currently proposed in the RDSGEIS and in the NYCRR are inadequate. Shale drilling and HVHF operations within 100'-150' of homes and public buildings pose a direct safety risk, not to mention the health and quality of life impacts presented. NYSDEC is proposing

[294] 2011 NYSDEC, RDSGEIS, Page 3-10.

[295] Well step-out distance that can be achieved will depend on well depth.

[296] BP, Extended-Reach Drilling: Breaking the 10-km Barrier, 1997.

to allow shale drilling and HVHF operations to run 24 hours a day, 7 days a week, which will result in significant impacts to human health and quality of life—disrupting sleep, work, schooling, and recreational patterns for nearby residents.



By comparison, the local zoning setback requirements for Barnett Shale development implemented in the urban area of Fort Worth, Texas are substantially larger than those proposed for NYS.[297] As shown in the figure below, the required setback from a home is six times larger at 600', as compared to NYS' 100' setback. Additionally, Fort Worth, Texas has implemented setbacks of at least 300' from public buildings and 600' from schools, which is more than double what is proposed by NYSDEC.[298]

At a state level, Wyoming requires a minimum setback of 350' from "water supplies, residences, schools, hospitals, and other structures where people are known to congregate."[299] The below photograph shows the proximity of homes to a well pad in Pennsylvania, where a 200' minimum setback from homes is required.[300]

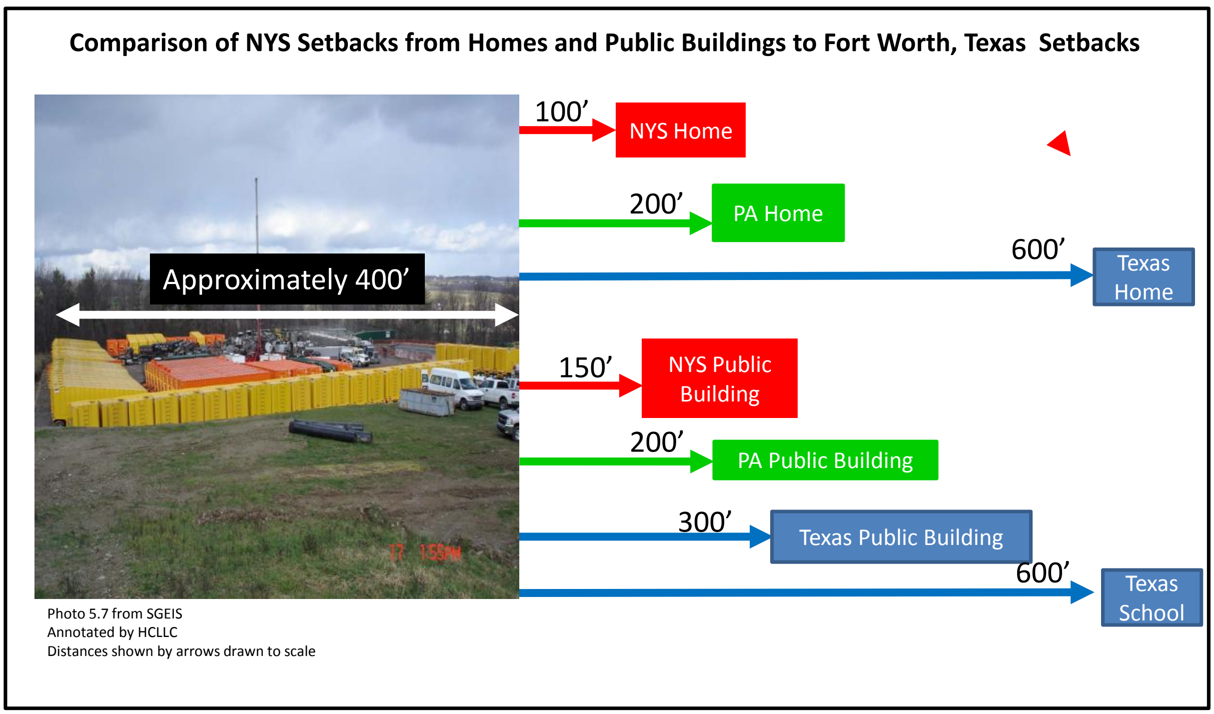
[297] Fort Worth Gas Drilling Regulations Presentation, Barnett Shale EXPO, March 11, 2009; the Code of Ordinances of the City of Forth Worth § 15-36(A).

[298] The Code of Ordinances of the City of Forth Worth § 15-34(N)(7), § 15-36(A).

[299] Wyo. Admin. Code OIL GEN Ch. 3 § 22(b).

[300] Governor's Marcellus Shale Advisory Commission Report, Prepared for Governor Corbett of Pennsylvania, July 22, 2011.

The photo above shows homes within close proximity to shale drilling operations in Hopewell Township, Washington County, PA.



Recommendation No. 68: Improved setbacks should be included in the SGEIS as a mitigation measure and codified in the NYCRR. Specifically, the SGEIS and NYCRR should be revised at 6 NYCRR § 553.2 to include the following minimum setbacks: homes, public buildings, and schools (1,320'; ¼ mile); private and public wells, primary aquifers, and other sensitive water resources (4,000'); and other water resources (660'; 1/8 mile). Additionally, NYSDEC should clarify the authority of local zoning authorities to establish minimum setbacks that are more protective than NYS' minimum standards in order for localities to address unique and site-specific local concerns and community characteristics.

In addition to the inadequate minimum setback requirements, the NYCRR allows an operator to move its surface location by 75’ without obtaining a permit amendment. 6 NYCRR § 552.3(b). Absent NYSDEC and public review, a 75’ adjustment is very significant, especially when setbacks as low as 50’ to 150’ are used. The regulations at 6 NYCRR § 552.3 explain that a 75’ surface location adjustment is allowed, without any permit amendment process, to account for surface obstructions or topography. However, if an operator’s due diligence and site planning during the original permit process include an examination of surface obstructions and topography, later adjustments should not be necessary.

Recommendation No. 69: The NYCRR should be revised at 6 NYCRR § 552.3 to allow the well location to be adjusted by 75’ without a permit amendment only if all the statewide and local setback requirements are still preserved.

The proposed regulations that govern HVHF SPDES permits also suffer from inadequate minimum setback requirements. The revisions proposed to 6 NYCRR § 750-3.3 include: a 4,000’ setback from an unfiltered water supply; a 500’ setback from a primary aquifer; no operations within a 100-year floodplain; and a 2,000’ setback from a public water supply, including wells, natural lakes, man-made impoundments, rivers and streams. However, neither the existing regulations nor the proposed revisions to 6 NYCRR § 750-3.3 include setbacks from streams, rivers, or other bodies of water that are not specifically designated as public water supplies. Thus, HVHF operations potentially could be as close as 50’ to streams, rivers, or other bodies of water, based on 6 NYCRR § 553.2. Also, the proposed regulations do not require a minimum setback of HVHF operations from private wells.

Further inconsistency is introduced in the proposed revisions to 6 NYCRR § 750-3.21, which prohibit HVHF operations within 100’ of a wetland. While this setback requirement is recognized in the RDSGEIS,[301] the proposed revisions to 6 NYCRR § 553.2 and 6 NYCRR § 560.4 do not include a parallel requirement. These sections of the regulations should be revised to include a wetland setback.

Recommendation No. 70: The NYCRR should be revised at 6 NYCRR § 553.2 to include a wetland setback of at least 100’ as described in the RDSGEIS.

The proposed revisions to 6 NYCRR § 750-3.21(f)(3) do not authorize the issuance of a SPDES permit for HVHF operations within 150’ of storm drains, lakes, ponds, and perennial or intermittent streams, which conflicts with the 50’ setback established at 6 NYCRR § 553.2. There remains confusion about which setbacks would be applied to lakes, ponds, and perennial or intermittent streams and rivers.

Recommendation No. 71: The NYCRR should be revised at 6 NYCRR § 750-3.3, 6 NYCRR § 750-3.2, 6 NYCRR § 553.2, and 6 NYCRR § 560.4 to provide consistent setback requirements that are protective of water sources, including rivers, streams, lakes, and private water supplies.

NYCRR should be clear that the intent, as stated in the RDSGEIS, is to measure setbacks from the edge of the drillsite, and to attempt to center wells on the drillsite to maximize the distance from the well to the drillsite edge.

Recommendation No. 72: NYCRR and the SGEIS should clarify that setbacks are measured from the edge of the drillsite. Wells should be centered on the well pad and should be set back at least 100’ from the pad edge, to maximize well setbacks from sensitive receptors.

[301] 2011 NYSDEC, RDSGEIS, Page 2-34.

19. Disposal of Drilling & Production Waste and Equipment Containing Naturally Occurring Radioactive Material (NORM)

Background: In 2009, HCLLC made recommendations to NYSDEC on best practices for disposal of drilling and production waste and equipment containing Naturally Occurring Radioactive Materials (NORM). NORM includes uranium, thorium, radium, and lead-210 and their decay products.[302] Additionally, radon, a component of natural gas, decays into radioactive polonium.

NORM can be brought to the surface in a number of ways during drilling, completion, and production operations:

- **<u>Drilling</u>**: Drill cuttings containing NORM are circulated to the surface.
- **<u>Completion</u>**: Wells stimulated using hydraulic fracture treatments inject water; a portion of that water flows back to the surface ("flowback") and can be contaminated by radioactive materials picked up during subsurface transport.
- **<u>Production</u>**: Subsurface water located in natural gas reservoirs, produced as a waste byproduct, may contain radioactive materials picked up by contact with gas or formations containing NORM (this water is called "produced water'). Equipment used in hydrocarbon production and processing can concentrate radioactive materials in the form of scale and sludge.

In January 2011, NYSDEC's consultant, Alpha Geoscience, agreed that the disposal of waste containing NORM is an important issue that should be addressed in the SGEIS. Alpha Geoscience's review of HCLLC's recommendations on NORM concluded that:

> *Harvey Consulting's recommendation to analyze practices for NORM testing, NORM treatment, and NORM disposal appears to be complete and well-researched. The review presents a concise analysis of practices involving the testing for and the treatment and disposal of NORM.*
>
> *Harvey Consulting's review of the dSGEIS's content regarding NORM is supported by a range of reliable sources. References include the EPA's website, USGS fact sheets, Texas Railroad Commission regulations, and a publication by Argonne National Laboratory.*[303]

Alpha Geoscience recommended that the SGEIS include a detailed analysis of NORM testing, treatment, transportation, and disposal methods:

> *Alpha suggests that **<u>it may be useful to operators if the SGEIS includes NYSDEC's detailed analyses of NORM testing, treatment, transportation, and disposal</u>**. This information may prove useful to the operator for developing handling and disposal plans [emphasis added].*[304]

[302] USEPA Oil and Gas Production Wastes, NORM, http://www.epa.gov/radiation/tenorm/oilandgas.html.

[303] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Pages 9-11.

[304] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 12.

Yet, Alpha Geoscience recommended against adopting specific regulations to formalize NORM testing, treatment, transportation, and disposal requirements in NYS; instead, Alpha Geoscience recommended that NYSDEC "consider" having "temporary guidelines:"

> ***Alpha suggests that NYSDEC consider having temporary guidelines regarding NORM*** *in place, to clarify expectations and requirements for operators prior to the commencement of operations. This also would be helpful to operators for the design of handling and disposal plans [emphasis added].*[305]

HCLLC disagrees with Alpha Geoscience's recommendation for temporary NORM disposal guidelines. The requirements for testing, treatment, transportation, and disposal of NORM should be formalized in NYCRR. The rules should be clear to industry and the public, and enforceable by NYSDEC.

The 2009 DSGEIS acknowledged that drilling and production waste and equipment may contain NORM. NYSDEC reports that the Marcellus Shale contains Uranium-238 and Radium-226, and this NORM may be present in drill cuttings, produced water, and stimulation treatment waste.[306] NYSDEC identified Radium-226 as the most significant NORM of concern, because it is water soluble and has a half-life of 1,600 years.[307] Radiation pathways can include external gamma radiation, ingestion, inhalation of particulates, and radon gas.[308]

In 2009, HCLLC recommended that the SGEIS address the potential for equipment scale and sludge to contain high concentrations of NORM. HCLLC explained that equipment (water lines, flow lines, injection wellheads, vapor recovery units, water storage tanks, heaters/treaters, and separators)[309] used to process natural gas and produced water containing NORM can become coated with radium scale and sludge deposits.[310] Scale precipitates from produced water when it is brought to the surface, cooled to lower temperatures, and subject to lower pressures.[311] The most common form of scale is barium sulfate, which readily incorporates radium in its structure. HCLLC noted that, because E&P waste is exempt from the federal Resource Conservation and Recovery Act (RCRA),[312] it is critical that states establish clear best practice requirements for handling E&P waste, especially for NORM found in equipment scale and sludge. HCLLC pointed out that other oil and gas states, such as Texas and Louisiana, have adopted stringent NORM regulations, including: occupational dose control, surveys; testing and monitoring; record keeping; signs and labeling; and treatment and disposal methods.[313]

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[305] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 11.

[306] 2009 NYSDEC, DSGEIS, Page 4-36.

[307] 2009 NYSDEC, DSGEIS, Page 6-129.

[308] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment-an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.

[309] Argonne National Laboratory, Radiological Dose Assessment Related to Management of Naturally Occurring Radioactive Materials Generated by the Petroleum Industry, Publication ANL/EAD-2, 1996.

[310] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment-an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.

[311] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment-an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.

[312] Environmental Protection Agency, Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations, EPA530-K-01-004, October 2002.

[313] 2009 NYSDEC, DSGEIS, Page 7-101.

The 2011 RDSGEIS: The 2011 RDSGEIS provided some improved data and acknowledged the risk of significant impacts from improperly disposed waste containing NORM. The RDSGEIS concluded that the NORM dataset is limited and there can be significant variability in NORM content. The 2011 RDSGEIS based its conclusions on data collected in other states; this data examined Marcellus Shale cuttings, produced water, and HVHF flowback.

However, the 2011 RDSGEIS still does not establish clear cradle-to-grave collection, testing, transportation, treatment, and disposal requirements for all waste containing NORM. The RDSGEIS is improved in that it establishes radioactive limitations and testing in some cases, but testing is still not required in all cases (even when data uncertainty exists). Long-term treatment and disposal requirements are not robust for all waste types. Nor is there a process in place to provide the public with information on NORM handling over the project life. For example:

- Radioactivity treatment and disposal threshold levels are established (e.g. for produced water and equipment); however, it is unclear if there is sufficient treatment and disposal capacity in NYS to handle the volume and amount of radioactive waste that may be generated;
- NYSDEC assumes that some waste will not contain significant amounts of radioactivity; yet, this assumption is based on a very limited dataset;
- There is no testing requirement to verify NORM content in drill cuttings before they are sent directly to a landfill; and
- Road spreading of waste is not prohibited; it is deferred to a yet-to-be determined future process outside the SGEIS review.

Recommendation No. 73: Detailed collection, testing, transportation, treatment, and disposal methods for each type of drilling and production waste and equipment containing NORM should be included in the SGEIS as a mitigation measure and codified in the NYCRR. Where data uncertainty exists, additional testing should be required. The radioactive content of waste should be verified to ensure appropriate transportation, treatment, and disposal methods are selected, and the testing results should be disclosed to the public.

Equipment Containing NORM: The 2011 RDSGEIS contains substantially improved requirements for equipment containing NORM, including a new radiation testing requirement and a treatment and disposal threshold limit. The RDSGEIS concludes that pipe scale and sludge (NORM buildup in equipment) can result in NORM concentrations that may have a significant adverse impact.

The 2011 RDSGEIS clarifies that NYSDOH will require the well operator to obtain a radioactive materials license for its facility when exposure rate measurements associated with scale accumulation in or on piping, drilling, and brine storage equipment exceeds 50 microR/hr[314] (μR/hr).[315] The RDSGEIS does not explain the origin of the 50 μR/hr limit; however, this limit has been used by a number of oil and gas producing states, including Texas[316] and Louisiana.[317]

[314] Microroentgens per hour (μR/hr) is a measurement of exposure from x-ray and gamma ray radiation in air.

[315] 2011 NYSDEC, RDSGEIS, Page 5-142.

[316] Texas Administrative Code, Title 16, Part 1, Chapter 4, Subchapter F, Economic Regulation, Railroad Commission of Texas, Environmental Protection, Oil and Gas NORM.

[317] Louisiana Administrative Code, Title 33 LAC Part XV, Radiation Protection.

Presumably, equipment containing a radioactive concentration of less than 50 μR/hr would be disposed of in a NYS landfill; however, it is unclear if NYS' landfills are designed to accommodate waste containing radioactivity of up to 50 μR/hr.

Recommendation No. 74: NYSDEC should explain the origin of the 50 μR/hr limit, and explain how NYS determined that this threshold is sufficiently protective for NYS. The SGEIS should explain where equipment containing a radioactive concentration of less than 50 μR/hr would be disposed (e.g. a NYS landfill), and whether this waste disposal method was designed for this waste handling purpose.

The RDSGEIS Chapter 7 (Section 7.7.2) proposes NORM testing (radiation survey) requirements:

> ***The Department proposes to require, via permit condition and/or regulation, that radiation surveys be conducted at specified time intervals for Marcellus wells developed by high-volume hydraulic fracturing completion methods on all accessible well piping, tanks, or other equipment that could contain NORM scale buildup.*** *The surveys would be required to be conducted for as long as the facility remains in active use. Once taken out of use no increases in dose rate are to be expected. Therefore, surveys may stop until either the site again becomes active or equipment is planned to be removed from the site. If equipment is to be removed, radiation surveys would be performed to ensure appropriate disposal of the pipes and equipment. All surveys would be conducted in accordance with NYSDOH protocols. The NYSDOH's Radiation Survey Guidelines and a sample Radioactive Materials Handling License are presented in Appendix 27. The Department finds that existing regulations, in conjunction with the proposed requirements for radiation surveys, would fully mitigate any potential significant impacts from NORM [emphasis added].*[318]

NYSDEC's proposal to require NORM testing (radiation surveys) for HVHF wells and equipment is an important improvement. This proposed mitigation measure is effectively translated into a permit condition. Appendix 10, Proposed EAF Addendum Requirements for HVHF, Condition No. 65, requires:

> *65) Periodic* ***radiation surveys must be conducted at specified time intervals*** *during the production phase for Marcellus wells developed by high-volume hydraulic fracturing completion methods. Such surveys must be performed on all accessible well piping, tanks, or equipment that could contain NORM scale buildup. The surveys must be conducted for as long as the facility remains in active use. If piping, tanks, or equipment is to be removed, radiation surveys must be performed to ensure their appropriate disposal. All surveys must be conducted in accordance with NYSDOH protocols [emphasis added].*[319]

However, this permit condition is only applied to HVHF wells and equipment. NORM can accumulate in all oil and gas equipment; therefore, this requirement is better suited for the NYCRR and should be applied to all oil and gas operations.

Additionally, it is recommended that the radiation testing frequency and method be specified. As explained in Dr. Glenn Miller's and Dr. Ralph Seiler's comments on the 2011 RDSGEIS, the test method is an important determinant in quantifying total radioactivity.[320] Furthermore, Dr. Glenn Miller and Dr.

[318] 2011 NYSDEC, RDSGEIS, Page 7-119.

[319] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 12.

[320] Miller, G. and Seiler, R., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

Ralph Seiler recommended that radiation testing not be limited to radium. For example, Dr. Ralph Seiler points out in his comments that while NYSDEC has identified Radium (Ra) as a contaminant of concern, NYSDEC has overlooked the potential significant unmitigated impact of Polonium 210 (^{210}Po) accumulating in pipe scale as a byproduct of radon decay (natural gas contains radon).[321]

> **Recommendation No. 75**: The requirement for radiation surveys should be codified in the NYCRR and applied to all oil and gas operations, not just HVHF operations. Radiation testing frequency and method should be specified to ensure that all potential radiation impacts are assessed and quantified. The proposed HVHF Permit Condition No. 65 could serve as a starting point for the NYCRR revisions.

Produced Water and Flowback Wastewater NORM: In 2009, HCLLC pointed out that water produced from wells can be rich in chloride, which enhances the solubility of other elements, including the radioactive element radium.[322] HCLLC also noted that flowback wastewater can contain NORM.

In 2009, NYSDEC reported that it had insufficient data on NORM in produced water and flowback wastewater, but acknowledged that NORM is present and is known to be found in elevated levels in produced water.

The Department of Energy (DOE) explains the presence of NORM in produced water:

> ***Because the water has been in contact with the hydrocarbon-bearing formation for centuries, it contains some of the chemical characteristics of the formation and the hydrocarbon itself.*** *It may include water from the reservoir, water injected into the formation, and any chemicals added during the production and treatment processes. Produced water is also called "brine" and "formation water."* ***The major constituents of concern in produced water are****:*
>
> - *Salt content (salinity, total dissolved solids, electrical conductivity)*
> - *Oil and grease (this is a measure of the organic chemical compounds*[323]
> - *Various natural inorganic and organic compounds or chemical additives used in drilling and operating the well*
> - ***Naturally occurring radioactive material (NORM).***
>
> *The physical and chemical properties of produced water vary considerably depending on the geographic location of the field, the geological host formation, and the type of hydrocarbon product being produced. Produced water properties and volume can even vary throughout the lifetime of a reservoir [emphasis added].*[324]

[321] Seiler, R., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

[322] US Department of Interior, Naturally Occurring Radioactive Materials (NORM) in Produced Water and Oil-Field Equipment-an Issue for the Energy Industry, USGS Fact Sheet FS-142-99.

[323] In addition to the major constituents of concern listed by DOE for produced water, Dr. Glenn Miller notes that both the gasoline and diesel range hydrocarbon fractions should be monitored, since they are more soluble than heavy hydrocarbons.

[324] United States Department of Energy, Produced Water Management Information System, http://www.netl.doe.gov/technologies/pwmis/intropw/index.html.

Since 2009, NYSDEC gathered additional information and improved the 2011 RDSGEIS to acknowledge and quantify the potential adverse impact of produced water radioactivity. Although NYSDEC's research shows that flowback waste may not contain significant concentrations of radioactive material, NYSDEC acknowledges it has a limited dataset, and proposes radiation surveys for both types of wastewater (flowback and produced water).

NYSDEC's proposal to require NORM testing (radiation surveys) for flowback and production brine is a significant improvement to the 2011 RDSGEIS, and this proposed mitigation measure was effectively translated into a permit condition. Appendix 10, Proposed EAF Addendum Requirements for HVHF, Condition No. 64, requires:

> *64) Flowback water recovered after high-volume hydraulic fracturing operations must be tested for NORM prior to removal from the site. Fluids recovered during the production phase (i.e., production brine) must be tested for NORM prior to removal.*[325]

However, this permit condition is only applied to HVHF wells and equipment. NORM can be present in all flowback wastewater, including hydraulic fracture treatments less than 300,000 gallons, and produced water from wells that are not subject to HVHF treatments. Therefore, this requirement is better suited for the NYCRR and should be applied to all oil and gas operations.

Additionally, it is recommended that the NORM testing method and frequency be specified. As explained in Dr. Glenn Miller's and Dr. Ralph Seiler's comments on the 2011 RDSGEIS, the test method is an important determinant in quantifying total radioactivity.[326]

Recommendation No. 76: The requirement to test produced water (production brine) and flowback wastewater (waste from hydraulic fracturing operations) should by codified in the NYCRR and applied to all oil and gas operations. NORM testing frequency and method should be specified. Proposed HVHF Permit Condition No. 64 could serve as a starting point for NYCRR revisions.

The RDSGEIS proposes to allow flowback wastewater and produced water to be disposed of at a Publically Owned Treatment Works (POTW), as long at the influent concentration of radium-226 (as measured prior to admixture with POTW influent) is limited to 15 pCi/L,[327] or 25% of the 60 pCi/L concentration value listed in 6 NYCRR Part 380-11.7.

> *The Department proposes to require, as a permit condition, that the permittee demonstrate that it has a source to treat or otherwise legally dispose of wastewater associated with flowback and production water prior to the issuance of the drilling permit.* ***<u>Disposal and treatment options include publicly owned treatment works, privately owned high volume hydraulic fracturing wastewater treatment and/or reuse facilities, deep-well injection, and out of state disposal.</u>***

[325] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 12.

[326] Miller, G. and Seiler, R., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

[327] Picocuries per gram (pCi/g) is a measure of the radioactivity in one gram of a material. One picocurie is that quantity of radionuclide(s) that decays at the rate of 3.7 x 10-2 disintegrations per second.

> ***<u>Flowback water and production water must be fully characterized prior to acceptance by a POTW for treatment</u>****. Note in particular Appendix C. IV of TOGS 1.3.8, Maximum Allowable Headworks Loading. The POTW must perform a MAHW analysis to assure that the flowback water and production water will not cause a violation of the POTW's effluent limits or sludge disposal criteria, allow pass through of unpermitted substances or inhibit the POTW's treatment processes. As a result, the SPDES permits for POTWs that accept this source of wastewater will be modified to include influent and effluent limits for Radium and TDS, if not already included in the existing SPDES permit, as well as for other parameters as necessary to ensure that the permit correctly and completely characterizes the discharge.* ***<u>In the case of NORM, anyone proposing to discharge flowback or production water to a POTW must first determine the concentration of NORM present in those waste streams to determine appropriate treatment and disposal options. POTW operators who accept these waste streams are advised to limit the concentrations of NORM in the influent to their systems to prevent its inadvertent concentration in their sludge.</u>*** *For example,* ***<u>due to the potentially large volumes of these waste waters that could be processed through any given POTW, as well as the current lack of data on the level of NORM concentration that may take place, it will be proposed that POTW influent concentrations of radium-226 (as measured prior to admixture with POTW influent) be limited to 15 pCi/L, or 25% of the 60 pCi/L concentration value listed in 6 NYCRR Part 380-11.7.</u>*** *As more data become available on concentrations in influent vs. sludge it is possible that this concentration limit may be revisited [emphasis added].*[328]

EPA data shows that produced water can contain 0.1 to 9,000 pCi/L of radium-226.[329] Therefore, it is reasonably foreseeable that there will be substantial volumes of wastewater that will exceed the 15 pCi/L POTW influent limit. NYSDEC has not proposed a waste treatment or disposal solution for wastewater that exceeds the 15 pCi/L POTW influent limit.

> **Recommendation No. 77**: The SGEIS should examine treatment and disposal options, and capacity within NYS, for wastewater exceeding 15 pCi/L radiation.

Additionally, it is unclear if NYS' POTWs are designed to treat incoming wastewater with 15 pCi/L radiation. The Federal Safe Drinking Water standard is 5 pCi/L[330] (radium-226 and radium -228 combined).[331] The 5 pCi/L threshold was set because of the increased risk of cancer above this level. Because the RDSGEIS does not examine NYS' POTW's ability to treat incoming wastewater with 15 pCi/L radiation, it does not provide an estimate of the expected radiation level at the POTW effluent. Therefore, it is not clear whether POTW effluent discharge at a level greater than 5 pCi/L could end up in a drinking water supply, or how NYSDEC plans to monitor and ensure that this does not happen.

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[328] 2011 NYSDEC, RDSGEIS, Page 6-58 and 6-59.

[329] USEPA Oil and Gas Production Wastes, Summary Table of Reported Concentrations of Radiation in TENORM, http://www.epa.gov/radiation/tenorm/sources.html#summary-table

[330] Measured as Radium 226 and Radium 228 combined.

[331] USEPA Federal Safe Water Drinking Water Standards for Radionuclides at http://water.epa.gov/drink/contaminants/index.cfm#List.

Recommendation No. 78: The SGEIS should examine whether NYS' POTWs are designed to treat incoming wastewater with 15 pCi/L radiation, and should predict the maximum effluent radiation level. The SGEIS should explain how NYSDEC will ensure that drinking water sources will not exceed 5 pCi/L radiation.

The 2011 RDSGEIS does not prohibit road spreading of waste; it deferred this decision to a yet-to-be determined future process outside the SGEIS review. Yet, other oil and gas producing states, such as Texas, specifically prohibit road spreading of waste containing NORM.[332] A study conducted by Argonne National Lab for the US Department of Interior (DOI) concluded that land spreading of diluted NORM waste presented the highest potential dose of exposure to the general public of all waste disposal methods studied.[333]

Most states dispose of wastewater using deep well injection or use it to enhance hydrocarbon recovery operations. Land disposal is not common for onshore operations. The Department of Energy reports that more than 98% of oil and gas wastewater from onshore operations is injected into underground disposal wells, which are regulated by EPA, or used for enhanced hydrocarbon recovery.[334] The 2009 DSGEIS explored produced water treatment and disposal options (e.g. injection wells, treatment plants, and road spreading),[335] but did not land on a best practice.

The 2011 RDSGEIS concludes there is not enough information available to allow for road spreading under a Beneficial Use Determination (BUD).[336] However, the RDSGEIS does not explicitly state that road spreading for any purpose is prohibited until NYSDEC and NYSDOH agree on exposure standards that will serve as thresholds for BUD determinations, with the proposed exposure standards undergoing a public review and comment period.

Since the current BUD does not require an operator to test for NORM,[337] it is unclear how NORM testing at the well site will be integrated into the BUD process. The level of NORM, if any, that will be allowed in fluids used for road spreading is also unclear. The 2011 RDSGEIS does not examine the cumulative impact of spreading small amounts of NORM repeatedly over the same area. It is recommended that land and road spreading of produced water and other waste containing NORM be **prohibited**. Produced water containing NORM should be returned to the subsurface formation from which it came, or should be handled at an approved waste treatment plant.

Recommendation No. 79: The SGEIS should explicitly state that land and road spreading for any purpose is prohibited until NYSDEC and NYSDOH agree on exposure standards that will serve as thresholds for BUD determinations, with the proposed exposure standards undergoing a public review and comment period.

[332] Texas Railroad Commission (TXRRC), 16 Texas Administrative Code, Title 16, Part 1, Chapter 4, Subchapter F, §4.601 - 4.632. "Disposal of Oil and Gas NORM Waste". The TCEQ has jurisdiction over the disposal of other NORM wastes.

[333] Argonne National Laboratory, Radiological Dose Assessment Related to Management of Naturally Occurring Radioactive Materials Generated by the Petroleum Industry, Publication ANL/EAD-2, 1996.

[334] Argonne National Laboratory, Produced Water Volumes and Management Practices in the United States, Report Prepared for United States Department of Energy, Report No. ANL/EVS/R-09/1, 2009.

[335] 2009 NYSDEC, DSGEIS, Page 5-131.

[336] 2011 NYSDEC, RDSGEIS, Page 7-60.

[337] The example BUD application provided in Appendix 12 requires testing for calcium, sodium, chloride, magnesium, total dissolved solids, pH, iron, barium, lead, sulfate, oil and grease, benzene, ethylbenzene, toluene and xylene, but not NORM.

The Environmental Protection Agency (EPA) identifies produced water pits (brine pits) as an outdated practice in cases where produced water contains NORM. If wastewater pond sediments pose a potential radiological health risk, tank sediments from wastewater stored in tanks also would pose a radiological health risk. EPA reports that:

> *Lined and/or earthen pits were previously used for storing produced water and other nonhazardous oil field wastes, hydrocarbon storage brine, or mining wastes. In this case, TENORM[338] in the water will concentrate in the bottom sludges or residual salts of the ponds.* ***Thus the pond sediments pose a potential radiological health risk****….produced waters are now generally reinjected into deep wells…No added radiological risks appear to be associated with this disposal method as long as the radioactive material carried by the produced water is returned in the same or lower concentration to the formations from which it was derived [emphasis added].[339]*

> **Recommendation No. 80**: The SGEIS should address testing of wastewater sediments, and explain the collection, transportation, treatment, and disposal methods for this potential radiological health risk.

Drill Cutting NORM: The 2011 RDSGEIS acknowledges the fact that drill cuttings can contain NORM, but makes a blanket assumption that the level of radiation from cuttings will be low. The RDSGEIS does not require site-specific testing to verify this assumption, nor does it preclude cuttings disposal in existing solid waste landfills. Instead, the RDSGEIS only recommends that the well operator consult with the landfill operator prior to drill cuttings disposal.

> *In New York State the* ***NORM in cuttings is not precluded by regulation from disposal in a solid waste landfill****,* ***though well operators should consult with the operators*** *of any landfills they are considering using for disposal regarding the acceptance of Marcellus Shale drill cuttings by that facility [emphasis added].[340]*

The 2011 RDSGEIS is unclear about the environmental and human health protections that would be achieved via the landfill consultation process. Appendix 10, Proposed EAF Addendum Requirements for HVHF, requires the operator to specify where it plans to dispose of cuttings, and requires evidence that the cuttings will go to a Part 360 solid waste landfill. However, the RDSGEIS does not provide scientific or engineering data to demonstrate that existing NYS landfills are properly designed and equipped to safely handle and store drill cuttings containing NORM.

NYSDEC acknowledges significant uncertainty about the NORM content of drill cuttings in Chapter 7, and raises questions as to whether there are sufficient data to fully assess NORM impacts at this time. The 2011 RDSGEIS states:

> ***Existing data from drilling in the Marcellus Formation*** *in other States, and from within New York for wells that were not hydraulically fractured,* ***shows significant variability in NORM content.*** *This variability appears to occur both between wells in different portions of the formation and at a given well over time. This makes it important that samples from wells in different locations within New York State are used to assess the extent of this variability.*

[338] TENORM is Technologically Enhanced Natural Occurring Radioactive Material.

[339] http://www.epa.gov/radiation/tenorm/oilandgas.html#disposalpast.

[340] 2011 NYSDEC, RDSGEIS, Page 5-129 and 5-130.

> ***__During the initial Marcellus development efforts, sampling and analysis would be undertaken in order to assess this variability__. These data would be used to determine whether additional mitigation is necessary to adequately protect workers, the general public, and environment of the State of New York [emphasis added].*[341]

Yet, the 2011 RDSGEIS does not propose NORM mitigation measures. It does not require drill cuttings testing prior to disposal in the landfill, nor does it establish a maximum allowed NORM disposal threshold for safe long-term cuttings disposal in a landfill.

> **Recommendation No. 81**: Drill cuttings should be tested for NORM prior to disposal in a landfill. A maximum allowed NORM threshold for drill cuttings disposal in the landfill should be clearly established and scientifically justified. Testing and threshold requirements should be included in the SGEIS as a mitigation measure and codified in the NYCRR. Waste exceeding the established NORM threshold should be handled under NYS' radioactive waste handling rules.

Chapter 5.2.4.2 of the 2011 RDSGEIS concludes that NORM content in drill cuttings is equivalent to background levels of radiation occurring naturally in the atmosphere. This conclusion is based on Geiger counter and gamma ray spectroscopy sampling methods.

Yet, Dr. Glenn Miller points out in his comments on the 2011 RDSGEIS[342] that gamma ray spectroscopy is insufficient to assess all radioactive constituents (e.g. polonium is radioactive and only a weak gamma ray emitter), and gamma ray measurements do not provide insight into the potential for drill cuttings containing NORM to later oxidize, leach, and concentrate NORM when disposed. Dr. Miller concludes that NYS likely has underestimated the amount of NORM in drill cuttings, and recommends NYS require additional testing methods to verify total radiation levels and better understand the potential for drill cuttings to later oxidize, leach, and concentrate NORM when disposed. Additional work is needed to verify whether the disposal of drill cuttings containing NORM in existing NYS landfills is a best practice.

> **Recommendation No. 82**: The SGEIS should provide scientific and engineering data to demonstrate that existing NYS landfills are properly designed and equipped to safely handle and store drill cuttings containing NORM, including lower concentrations of NORM that could cumulatively have a significant impact when stored in large volumes over long periods of time. The SGEIS should examine the potential for drill cuttings containing NORM to later oxidize, leach, and concentrate radioactive materials within the landfill. If NYSDEC cannot provide scientific and engineering data to demonstrate that existing NYS landfills are properly designed and equipped to safely handle and store drill cuttings containing NORM, it should identify alternative collection, transportation, treatment, and disposal requirements.

NYCRR Proposed Revisions: Proposed Permit Condition No. 53 requires waste fluids be handled in accordance with 6 NYCRR § 554.1(c)(1); yet, this regulation does not specify the best practice for handling hydraulic fracturing fluid and other drilling and completion wastes. Instead, 6 NYCRR § 554.1(c)(1) merely provides a process for the applicant to submit a waste management plan. In 2009, HCLLC recommended revisions to this regulation; yet, none are proposed. The existing regulation states:

> *Prior to the issuance of a well-drilling permit for any operation in which the probability exists that brine, salt water or other polluting fluids will be produced or obtained during drilling operations in **__sufficient quantities__** to be deleterious to the surrounding environment, the operator*

[341] 2011 NYSDEC, RDSGEIS, Page 7-119.

[342] Miller, G., Comments Prepared for NRDC on 2011 NYSDEC, DSGEIS, 2012.

> *must submit and receive approval for a plan for the environmentally safe and proper ultimate disposal of such fluids. For purposes of this subdivision, drilling muds are not considered to be polluting fluids. Before requesting a plan for disposal of such fluids, the department will take into consideration the known geology of the area, the sensitivity of the surrounding environment to the polluting fluids and the history of any other drilling operations in the area.* ***<u>Depending on the method of disposal chosen by the applicant</u>****, a permit for discharge and/or disposal may be required by the department in addition to the well-drilling permit. An applicant may also be required to submit an acceptable contingency plan, the use of which shall be required if the primary plan is unsafe or impracticable at the time of disposal [emphasis added].*

Terms such as "sufficient quantities" are ambiguous, providing operators and regulators large latitude in how they interpret the regulation. Regulations should specify technically and scientifically based thresholds and management practices.

Under 6 NYCRR § 554.1(c)(1), the waste disposal method is selected by the applicant, with no instruction on how to determine the best waste management practice. While recycling and the reuse of fracturing fluid are discussed in the RDSGEIS, there is no requirement in the proposed permit conditions to use this best practice. Furthermore, NYSDEC does not explain how it will oversee the recycling and reuse processes.

Recommendation No. 83: Revisions are needed to 6 NYCRR § 554.1(c)(1) to require a more robust waste management planning and oversight process, including detailed instructions on collection, testing, transportation, treatment, and disposal of waste.

20. Hydrogen Sulfide

Background: In 2009, HCLLC recommended that the NYCRR require operators to follow American Petroleum Institute Recommended Practice 49 (API RP 49) for Drilling and Well Servicing Operations Involving Hydrogen Sulfide, and API RP 55 for Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide, to protect employees and the public.

The 2011 RDSGEIS: The 2011 RDSGEIS reports that Marcellus Shale operations in Pennsylvania have not produced substantial amounts of H_2S.[343] However, this conclusion is based on limited information from wells drilled only in Pennsylvania. These data do not confirm that H_2S will not be present initially or over time in NYS wells.

H_2S gas produces a malodorous smell of rotten eggs at low concentrations, can cause serious health symptoms at elevated concentrations, and can be deadly at the higher concentrations found in some oil and gas wells.

The Occupational Safety and Health Administration (OSHA) recommends close monitoring of H_2S for human health and explosion mitigation:

> *Hydrogen Sulfide or sour gas (H2S) is a flammable, colorless gas that is toxic at extremely low concentrations. It is heavier than air, and may accumulate in low-lying areas. It smells like "rotten eggs" at low concentrations and causes you to quickly lose your sense of smell. Many areas where the gas is found have been identified, but pockets of the gas can occur anywhere.*
>
> *Iron sulfide is a byproduct of many production operations and may spontaneously combust with air.*
>
> *Flaring operations associated with H_2S production will generate Sulfur Dioxide (S02), another toxic gas.*
>
> *Active monitoring for hydrogen sulfide gas and good planning and training programs for workers are the best ways to prevent injury and death.*[344]

The American Conference of Governmental Industrial Hygienists recommends a Threshold Limit Value of 10ppm and a short-term exposure (STEL) limit of 15 ppm, averaged over 15 minutes, for the action level indicating the need for respiratory protection.[345] While workers may be afforded respiratory protection, nearby members of the public do not have routine access to respiratory protection and monitoring systems. Routine, standardized testing should also be in place to ensure public health and safety.

A 300 ppm concentration of H_2S is considered by the American Conference of Governmental Industrial Hygienists as Immediately Dangerous to Life and Health.

[343] 2011 NYSDEC, RDSGEIS, Page 5-138.

[344] OSHA website at http://www.osha.gov/SLTC/etools/oilandgas/general_safety/h2s_monitoring.html.

[345] OSHA website at http://www.osha.gov/SLTC/etools/oilandgas/general_safety/appendix_a.html.

In low concentrations, H_2S sometimes can be detectable by its characteristic odor; however, the smell cannot be relied upon to forewarn of dangerous concentrations (greater than 100ppm) of the gas because it rapidly paralyzes the sense of smell due to paralysis of the olfactory nerve. A longer exposure to the lower concentrations has a similar desensitizing effect on the sense of smell.

It should be well understood that the sense of smell will be rendered ineffective by hydrogen sulfide, which can result in an individual failing to recognize the presence of dangerously high concentrations. Exposure to hydrogen sulfide causes death by poisoning the respiratory system at the cellular level. [346]

Therefore, proper handling of H_2S is important from both a quality-of-life and human-safety standpoint for workers and nearby public.

While H_2S may not be initially present at a drillsite, the operator must remain vigilant in monitoring for H_2S over time, because sulfate reducing bacteria and other forms of acid producing bacteria can generate H_2S in the reservoir, such that H_2S concentrations elevate over time. Increasing levels of H_2S is a common problem in waterflooding operations in oil and gas fields. Biocides are typically used to mitigate bacteria growth; however, sometimes biocides are not successful.

Biocide use and close monitoring of H_2S early in field development is an important mitigation measure, because once elevated H_2S is present it is difficult to control. Industry anticipates H_2S will be a future concern in operations requiring large volumes of water for HVHF treatments, especially where treatment fluid is recycled, as planned in NYS. A 2010 Apache Corporation paper summarizes the problem:

One of the most severe threats in recycling waters for fracs is the control of bacteria (Tischler, 2009), including sulfate reducing bacteria (SRBs) and other forms such as acid producing bacteria (APB), iron fixing bacteria and slime formers. SRBs have created souring of some conventional reservoirs from injection of waters, both produced and semi-fresh, which have established a presence in the reservoirs and create H_2S gas and iron sulfide problems. *Local well fouling problems are common where SRBs are spiked into the formation from drilling or completion fluids. This type of H_2S occurrence may cause local corrosion…in shale, however, the effect of uncontrolled bacteria is a general unknown, given the extremely large volumes of surface water used for slick water fracturing. For this reason, recycling of the water may seed all waters with bacteria and/or concentrate the bacteria; thus bacterial control is a necessity [emphasis added].* [347]

Due to the potential close proximity of Marcellus Shale operations to the public, a robust initial monitoring program should be instituted to determine H_2S concentrations in Marcellus Shale gas throughout NYS. As described in American Petroleum Institute Recommended Practices 49 and 55, monitoring frequency can be adjusted over time as site-specific information is obtained. Initial sampling should be conducted at each drillsite, with at least monthly sampling thereafter.

[346] OSHA website at http://www.osha.gov/SLTC/etools/oilandgas/general_safety/appendix_a.html

[347] King, G.E., Apache Corporation, Thirty Years of Gas Shale Fracturing: What Have We Learned?, Society of Petroleum Engineers Technical Paper, SPE 133456, 2010, Page 30.

Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing, Permit Condition No. 25 includes a requirement to conform with API RP 49; however, there is no requirement for operators to conform with API RP 55, which applies after the well is drilled, during production operations.

NYCRR Proposed Revisions: As a control measure, when H_2S is present, the proposed regulations at 6 NYCRR § 560.6(c)(28) require the venting of any gas containing H_2S through a flare stack to combust the dangerous vapors.

Recommendation No. 84: H_2S monitoring and reporting requirements should be included in the RDSGEIS as a mitigation measure and codified in the NYCRR. Operators should be required to follow H_2S detection and handling procedures to protect employees and the public. Initial H_2S testing should be conducted at each drillsite. Subsequent test frequency should be based on the results of initial testing. H_2S levels can increase over time as gas fields age and sour. H_2S requirements should be included in regulation for both drilling and production operations, and should not just be relegated to a drilling permit condition. Additionally, when H_2S is present, nearby neighbors, local authorities, and public facilities should be notified, and provided information on the safety and control measures that the operator will undertake to protect human health and safety. In cases where elevated H_2S levels are present, audible alarms should be installed to alert the public when immediate evacuation procedures are warranted.

21. Chemical & Waste Tank Secondary Containment

Background: In 2009, HCLLC recommended that NYCRR be revised to include secondary containment for chemicals stored on the well pad or, alternatively, require the use of double-wall tanks. Chemicals, especially corrosive chemicals, can result in storage container leaks and spills to the environment. Best practice for permanent chemical storage is to install secondary containment under the storage container, and ensure the containers are not in contact with soil or standing water.[348] Shale gas drilling and HVHF operations include the use of many chemical tanks and waste handling tanks (e.g. flowback tanks) that warrant secondary containment.

2011 RDSGEIS: NYSDEC responded to public comments and made appropriate revisions to the 2011 RDSGEIS with its requirement for 110% secondary containment for all chemical and waste handling tanks. It also requires secondary containment for chemical and waste transport, mixing and pumping equipment. The 2011 RDSGEIS states:

> *Flowback water stored on-site must use covered watertight tanks within secondary containment and the fluid contained in the tanks must be removed from the site within certain time periods.*[349]
>
> *Secondary containment would be required for all fracturing additive containers and additive staging areas. These requirements would be included in supplementary well permit conditions for high-volume hydraulic fracturing.*[350]
>
> *Secondary containment measures may include one or a combination of the following; dikes, liners, pads, curbs, sumps, or other structures or equipment capable of containing the substance. Any such secondary containment would be required to be sufficient to contain 110% of the total capacity of the single largest container or tank within a common containment area.*[351]
>
> *Secondary containment for flowback tanks is required.*[352]
>
> *The Department proposes to require that operators storing flowback water on-site would be required to use watertight tanks located within secondary containment, and remove the fluid from the wellpad within specified time frames.*[353]
>
> *Location of additive containers and **transport, mixing and pumping equipment**…within secondary containment…[emphasis added]*[354]

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[348] Bureau of Land Management, Surface Operating Standards and Guidelines for Oil and Gas Exploration and Development, The Gold Book, 2007.

[349] 2011 NYSDEC, RDSGEIS, Executive Summary, Page 25.

[350] 2011 NYSDEC, RDSGEIS, Page 7-38.

[351] 2011 NYSDEC, RDSGEIS, Page 7-38.

[352] 2011 NYSDEC, RDSGEIS, Page 7-40.

[353] 2011 NYSDEC, RDSGEIS, Page 1-12.

[354] 2011 NYSDEC, RDSGEIS, Page 7-29.

> **Recommendation No. 85**: Secondary containment requirements for well site chemicals should be applied as a best practice to all oil and gas development and codified in NYCRR, and should not be limited to shale gas and HVHF operations.

NYCRR Proposed Revisions: Proposed regulations codify the requirement for secondary containment for chemical and waste handling tanks, but do not specifically address secondary containment for chemical and waste transport, mixing and pumping equipment.

> **Recommendation No. 86**: Consistent with the proposed RDSGEIS mitigation, 6 NYCRR § 750-3.11 and 6 NYCRR § 560.6 should be revised to require lined secondary containment for chemical and waste transport, mixing, and pumping equipment.

Proposed regulations at 6 NYCRR § 750-3.11 provide very specific instructions on how to construct adequate secondary containment, including the use of coated or lined materials that are chemically compatible with the environment and the substances they may contain. Regulations also state that the containment structures must have adequate freeboard, be protected from damage, and be able to contain at least 110% of the largest tank volume.

> ***750-3.11 Applications of standards, limitations and other requirements***
>
> *(e) The HVHF SWPPP must, at a minimum, include the HVHF SWPPP General Requirements listed in subparagraph (1) below, Structural Best Management Practices (BMPs), Non-structural BMPs, and Activity-Specific SWPPP Requirements.*
>
> *(v) Secondary Containment - To prevent the discharge of hazardous substances, the owner or operator shall provide, implement, and operate secondary containment measures.* ***Such secondary containment shall be: (a) designed and constructed in accordance with good engineering practices, (b) constructed, coated or lined with materials that are chemically compatible with the environment and the substances to be contained, (c) provide adequate freeboard, (d) protected from heavy vehicle or equipment traffic; and have a volume of at least 110 percent of the largest storage tank within the containment area*** *[emphasis added].*

In contrast, proposed regulations at 6 NYCRR § 560.6 offer substantially less instruction on how to construct adequate secondary containment. They do not mandate the use of coated or lined materials that are chemically compatible with the environment and the substances they may contain. They do not require the containment structure have adequate freeboard. Nor do they require that the containment be protected from damage.

> ***§560.6 Well Construction and Operation.***
>
> *(c) Drilling, Hydraulic Fracturing and Flowback.*
>
> *(26) Hydraulic fracturing operations must be conducted as follows:*
>
> *(i) secondary containment for fracturing additive containers and additive staging areas, and flowback tanks is required.* ***Secondary containment measures may include, as deemed appropriate by the department, one or a combination of the following: dikes, liners, pads, impoundments, curbs, sumps or other structures or equipment capable of containing the substance****. Any such secondary containment must be sufficient to contain*

> *110 percent of the total capacity of the single largest container or tank within a common containment area. No more than one hour before initiating any hydraulic fracturing stage, all secondary containment must be visually inspected to ensure all structures and equipment are in place and in proper working order [emphasis added].*

> **Recommendation No. 87**: 6 NYCRR § 560.6 should be revised to include specific secondary containment construction standards that are consistent with 6 NYCRR § 750-3.11.

Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing: Permit conditions have been developed to require secondary containment. However, the permit conditions merely echo proposed regulations at 6 NYCRR § 560.6. They do not provide additional or supplemental requirements to the NYCRR.

> **Recommendation No. 88**: Streamline the Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing contained in the RDSGEIS to remove requirements that are redundant with NYCRR, or if retained, ensure that permit language matches the final codified version of NYCRR and cite the NYCRR requirements.

22. Fuel Tank Containment

Background: In 2009, HCLLC recommended that the NYCRR be revised to require more stringent oil spill prevention measures for temporary fuel tanks associated with drilling and well stimulation activities, and that NYS' regulations be at least as stringent as federal EPA's Spill Prevention Control and Countermeasures (SPCC) Plan. HCLLC recommended that NYSDEC incorporate existing EPA oil spill prevention standards into the NYCRR. EPA standards require secondary containment if a facility stores 1,320 gallons of fuel or more (30 CFR § 112), including portable, temporary fuel tanks.

In 2009, NYSDEC proposed to exempt drilling rig and HVHF fuel tanks (even those as large as 10,000 gallons) from NYS' petroleum bulk storage regulations and tank registration requirements at 6 NYCRR §§ 612-614, citing the fact that the storage tanks are temporary (non-stationary) as the reason for the exemption. This problem persists in the 2011 RDSGEIS.

HCLCC questioned NYSDEC's rationale for exempting drilling rig and HVHF fuel tanks from NYS' spill prevention regulations, as all other tanks 1,100 gallons and larger must register in NYS, install secondary containment, and undergo inspections at 5- and 10-year intervals.

HCLLC pointed out that a temporary fuel tank poses a greater environmental risk than a stationary fuel tank, because temporary fuel tanks are relocated many times during their operating lives, increasing the potential for tank damage during transit and the likelihood of tank appurtenance leakage.

Large temporary fuel tanks should be subject to the same secondary containment requirements as large stationary fuel tanks in NYS, particularly in situations where temporary fuel tanks are installed in one location for a significant period of time (e.g. a multi-well pad where drilling and completion operations could span several years). Alternatively, where secondary containment is not technically feasible, the use of double-walled or vaulted tanks should be considered for portable fuel tanks.

In January 2011, NYS' consultant, Alpha Geoscience, reviewed HCLLC's recommendation and provided NYSDEC with incorrect guidance on EPA's secondary containment requirements for onshore oil drilling workover and mobile equipment and other fuel storage.[355] Alpha Geoscience advised NYSDEC that EPA's SPCC regulations only addressed stationary fuel tanks greater than 1,320 gallons.

Alpha Geoscience's advice was incorrect because EPA's SPCC rules apply to facilities that have an aggregate fuel or hydrocarbon storage of 1,320 gallons or more at a facility, and secondary containment rules are not limited to stationary tanks.[356]

2011 RDSGEIS: NYSDEC's 2011 proposal for fuel tank secondary containment is confusing and inconsistent. The RDSGEIS both recommends and requires fuel tank secondary containment as a best practice, yet also exempts large fuel tanks used for drilling and HVHF operations.

For example, the 2011 RDSGEIS states that secondary containment will be required for fuel tanks and areas where fuel transfers occur:

[355] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 21.

[356] USEPA, SPCC Guidance for Regional Inspectors Version 1.0, November 28, 2005, Page 2-16.

> ***The Department proposes to require****, via permit condition and/or new regulation, that* ***operators provide secondary containment around all*** *additive staging areas and* ***fueling tanks, manned fluid/fuel transfers and visible piping and appropriate use of troughs, drip pads or drip pans*** *[emphasis added].*[357]

NYSDEC supports its recommendation for fuel tank secondary containment by pointing out that its consultant has identified it as a best management practice:

> *In addition to its regulatory survey, Alpha also reviewed and discussed best management practices directly observed in the northern tier of Pennsylvania and noted that "[t]he reclamation approach and regulations being applied in PA may be an effective analogue going forward in New York."* ***The best management practices referenced by Alpha include…Secondary containment structures around petroleum storage tanks and lined trenches to direct fluids to lined sumps where spills can be recovered without environmental contamination*** *[emphasis added].*[358]

Yet, the 2011 RDSGEIS exempts large fuel tanks from secondary containment by designating drilling rig and HVHF fuel tanks as "temporary":

> *The diesel tank fueling storage associated with the larger rigs described in Chapter 5 may be larger than 10,000 gallons in capacity and may be in one location on a multi-well pad for the length of time required to drill all of the wells on the pad. However, the tank would be removed along with the rig during any drilling hiatus between wells or after all the wells have been drilled. There are no long-term or permanent operations at a drill pad which require an on-site fueling tank.* ***Therefore, the tank is considered non-stationary and is exempt from the Department's petroleum bulk storage regulations and tank registration requirements*** *[emphasis added].*[359]

The 2011 RDSGEIS does not explain why a temporary fuel tank would pose less risk of a spill than a stationary fuel tank.

The 2011 RDSGEIS further confuses the issue by stating that all fuel tanks would be included in secondary containment:

> *The following measures are proposed to be required, via permit condition and/or regulation, to prevent and mitigate spills.* ***For all wells subject to the SGEIS****, supplementary permit conditions for high-volume hydraulic fracturing* ***would include the following requirements with respect to fueling tanks and refilling activities****:*
>
> > *a.* ***Secondary containment consistent with the objectives of SPOTS 10 for all fueling tanks****.*
> >
> > ***The secondary containment system could include one or a combination of the following: dikes, liners, pads, holding ponds, curbs, ditches, sumps, receiving tanks or other equipment capable of containing spilled fuel****. Soil that is used for secondary containment would be of such character that a spill into the soil will be readily recoverable and would result in a minimal amount of soil contamination and*

[357] 2011 NYSDEC, RDSGEIS, Page 1-11.
[358] 2011 NYSDEC, RDSGEIS, Page 8-5.
[359] 2011 NYSDEC, RDSGEIS, Page 7-343.

> *infiltration. Draft Department Program Policy DER-1730 may be consulted for permeability criteria for dikes and dike construction standards, including capacity of at least 110% of the tank's volume [emphasis added].* [360]

Ultimately, the 2011 RDSGEIS, includes secondary containment requirements for all fuel tanks, in Appendix 10, Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing.

> 13) ***Secondary containment*** *consistent with the Department's Spill Prevention Operations Technology Series 10, Secondary Containment Systems for Aboveground Storage Tanks,(SPOTS 10)* ***is required for all fueling tanks*** *[emphasis added];*
>
> 14) *To the extent practical, fueling tanks must not be placed within 500 feet of a public or private water well, a domestic-supply spring, a reservoir, a perennial or intermittent stream, a storm drain, a wetland, a lake or a pond;*
>
> 15) *Fueling tank filling operations must be manned at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck, and;*
>
> 16) *Troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment.* [361]

While, it is useful that the RDSGEIS finally lands on requiring secondary containment for fuel tanks, there remains a conflict in the text where NYSDEC has proposed to exempt temporary fuel tanks.

Recommendation No. 89: The SGEIS text should be revised to remove the temporary fuel tank exemption from secondary containment described on page 7-34.

Additionally, Appendix 10 permit conditions merely echo proposed regulations at 6 NYCRR § 560.6, and do not provide additional or supplemental requirements to the NYCRR. Therefore, if adopted into regulation, the permit conditions could be streamlined.

Recommendation No. 90: Streamline the Proposed Supplementary Permit Conditions for High-Volume Hydraulic Fracturing to remove requirements that are redundant with the proposed revisions to NYCRR, or if retained, ensure that permit language matches the final codified version of NYCRR and cite the NYCRR requirements.

NYCRR Proposed Revisions: The proposed regulations at 6 NYCRR § 560.6 codify the requirement for fuel tank secondary containment, and set no limit on the size or duration of fuel tank use. These proposed regulations are protective of the environment. The RDSGEIS should be revised to be consistent with the proposed regulations, avoiding future confusion about NYSDEC's intent.

> **§560.6 Well Construction and Operation.**
>
> *(b) Site Maintenance*.
>
> *(1) For any well:*

[360] 2011 NYSDEC, RDSGEIS, Page 7-34.

[361] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 3.

(i) ***<u>secondary containment is required for all fueling tanks</u>*** *[emphasis added];*

(ii) to the extent practical, fueling tanks must not be placed within 500 feet of a perennial or intermittent stream, storm drain, wetland, lake or pond;

(iii) fueling tank filling operations must be supervised at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck; and

(iv) troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment required by subparagraph (i) of this subdivision.

Recommendation No. 91: The SGEIS should be revised to be consistent with the proposed regulations, which require secondary containment for all fuel tanks (6 NYCRR § 560.6) used for shale gas drilling and HVHF operations.

While proposed regulations at 6 NYCRR § 560.6 are useful because they make it clear that secondary containment is required for all fuel tanks, the proposed regulations do not provide specific instruction on how to construct adequate containment.

Recommendation No. 92: 6 NYCRR § 560.6 should be revised to clearly state that all fuel tank secondary containment should be designed and constructed in accordance with good engineering practices, incremental to the minimum federal standards. Good engineering practices include: using coated or lined materials that are chemically compatible with the environment and the substances to be contained; providing adequate freeboard; protecting containment from heavy vehicle or equipment traffic; and having a volume of at least 110 percent of the largest storage tank within the containment area.

NYCRR Proposed Revisions: The proposed regulations at 6 NYCRR § 560.6 require a 500' setback for fuel tanks from perennial or intermittent streams, storm drains, wetlands, lakes, and ponds, but only to the "extent practical" with no explanation of what that means in real terms, and under what conditions it would be acceptable to place a fuel tank closer. NYCRR does not include any setbacks from homes or public facilities.

<u>§560.6 Well Construction and Operation.</u>

<u>(b) Site Maintenance</u>.

(1) For any well:

(i) secondary containment is required for all fueling tanks;

(ii) ***<u>to the extent practical</u>****, fueling tanks must not be placed within 500 feet of a perennial or intermittent stream, storm drain, wetland, lake or pond[emphasis added];*

(iii) fueling tank filling operations must be supervised at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck; and

(iv) troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment required by subparagraph (i) of this subdivision.

Recommendation No. 93: Proposed regulations at 6 NYCRR § 560.6 (b)(1)(ii) should be revised to delete the term "to the extent practical," and should include minimum setbacks for fuel tanks from homes and public buildings.

Additionally, the RDSGEIS is problematic because it still references a **draft** NYSDEC Program Policy (DER-17) for construction standards and a September 28, 1994 Spill Prevention Operations Technology Series (SPOTS) memo for guidance on secondary containment construction.

Recommendation No. 94: The SGEIS should not rely on a draft[362] NYSDEC Program Policy document (DER-17) for construction standards and an outdated September 28, 1994 Spill Prevention Operations Technology Series (SPOTS) memo for guidance on secondary containment construction. Instead, secondary containment requirements for fuel tanks should be codified in the NYCRR and written in a way that is clear, consistent, and enforceable.

The importance of secondary containment for fuel tanks extends beyond shale gas drilling and HVHF operations to all hydrocarbon drilling and HVHF operations.

Recommendation No. 95: Secondary containment requirements for fuel tanks should extend to all hydrocarbon drilling and HVHF operations in NYS. The requirements should not be limited to shale gas drilling and HVHF operations. Therefore, the recommendations made above should be captured in both 6 NYCRR § 560 and 6 NYCRR § 554.

The RDSGEIS does not cite existing EPA spill prevention requirements at 40 CFR § 112, which apply to all fuel tanks, including drilling tanks, at 40 CFR § 112.7(c) and 40 CFR § 112.10(c). EPA's regulations, which were revised in 2002, require secondary containment for fuel tanks at facilities storing 1,320 gallons and more. EPA allows an operator the opportunity to demonstrate under 40 CFR § 112.7(d) that it is impracticable to install secondary containment; however, EPA requires a formal written "impracticability determination." Under this determination, EPA requires periodic tank integrity testing, leak testing of the valves and associated piping, a Part 109 contingency plan, and a written commitment of manpower, equipment, and materials to respond to a spill.

Recommendation No. 96: The SGEIS should cite federal standards (similar to how NYSDEC cited relevant USEPA standards for air quality) and notify the operator that the federal standards must be met. The SGEIS should also clearly explain what additional requirements will be imposed by NYS.

The RDSGEIS should also include: periodic fuel tank inspections to examine structural conditions and document corrosion or damage; the installation of high-liquid-level alarms that sound and display in an immediately recognizable manner; the installation of high-liquid-level automatic pump shutoff devices, which are designed to stop flow at a predetermined tank content level; and a means of immediately determining the liquid level of tanks.

Recommendation No. 97: In the NYCRR, NYSDEC should require tank inspections and tank alarm systems.

[362] If NYSDEC decides to refer to policy and guidance documents, those documents at a minimum should be final documents, and NYSDEC should state within those documents that the contents are enforceable.

NYSDEC does not address whether vaulted, double-walled, or self-diking tanks can be used as alternatives to constructing large temporary containment areas. Other oil and gas producing states allow the use of vaulted, self-diking, or double-walled portable tanks to meet the secondary containment requirement in cases where the operator can demonstrate that it is infeasible to install a containment area meeting EPA's 110% of the largest tank volume requirement. NYSDEC could consider allowing these alternative tanks in places where secondary containment is proven to be infeasible.

Vaulted, self-diking, and double-walled portable tanks are equipped with catchments that hold fuel overflow or divert it into an integral secondary containment area. Industry standards for the construction of vaulted, self-diking, and double-walled portable tanks include:

- Underwriters Laboratories' Steel Aboveground Tanks for Flammable and Combustible Liquids (UL 142);
- Appendix J of the American Petroleum Institute's (API) Welded Steel Tanks for Oil Storage (API 650); and
- API's Specification for Shop Welded Tanks for Storage of Production Liquids (API Spec 12F).

Due to the higher potential for damage during relocation and use at multiple sites, it is recommended that inspections be routinely performed on vaulted, self-diking, and double-walled portable tanks. The inspections should identify damage and corrosion using one of the following standards:

- Steel Tank Institute's (STI) Standard for the Inspection of Aboveground Storage Tanks, Third Edition (STI SP00l); or
- API's Tank Inspection, Repair, Alteration, and Reconstruction Standard (API 653).

As an oil spill prevention measure, portable tanks can be equipped with high-liquid-level alarms that sound and display in an immediately recognizable manner; high-liquid-level automatic pump shutoff devices, which are designed to stop flow at a predetermined tank content level; and a means of immediately determining the liquid level of tanks.

Recommendation No. 98: NYSDEC should clarify whether vaulted, self-diking, and double-walled portable tanks will be allowed, and codify in the NYCRR the requirements for the use of those tanks, including inspections and spill prevention alarm systems.

23. Corrosion & Erosion Mitigation & Integrity Monitoring Programs

Background: In 2009, HCLLC recommended that NYSDEC require corrosion and erosion mitigation programs. More specifically HCLLC recommended that: equipment be designed to prevent corrosion and erosion; monitoring programs be put into place to identify corrosion and erosion over the well and equipment operating lifetime; and repair and replacement of damaged wells and equipment be completed.

Downhole tubing and casing, surface pipelines, pressure vessels, and storage tanks used in oil and gas exploration and production can be subject to internal and external corrosion. Corrosion can be caused by water, corrosive soils, oxygen, corrosive fluids used to treat wells, and the carbon dioxide (CO_2) and hydrogen sulfide (H_2S) present in gas. High velocity gas contaminated with water and sediment can internally erode pipes, fittings, and valves.

HVHF treatments, if improperly designed, can accelerate well corrosion. Additionally, acids used to stimulate well production and remove scale can be corrosive. The 2011 RDSGEIS includes a discussion on corrosion inhibitors used by industry in fracture treatments, but does not require them as best practice. Furthermore, the RDSGEIS does not require facilities be designed to resist corrosion (e.g. material selection and coatings), nor does it require corrosion monitoring, or the repair and replacement of corroded equipment.[363]

As explained in Chapter 20 of this report, the use of recycled HVHF fluid can result in the inoculation of sulfate reducing bacteria in the reservoir, and increased downhole equipment corrosion. And, while NYSDEC indicates that H_2S levels may be initially low in the Marcellus Shale, this may not be the case during the full life-cycle of the well. Nor does the RDSGEIS examine the H_2S of all other low permeability gas reservoirs to know what the H_2S might be for those formations.

Corroded well casings can provide a pathway for gas and well fluids to leak into protected aquifers. Therefore, it is important to install a robust casing system, and it's equally important to ensure that the casing system's integrity is maintained during the well's life.

Corrosion measured on production casing is an important piece of information, because corrosive fluids are known to also degrade the quality of the cement barrier. Corrosive fluids reduce the cement strength and make it more permeable, potentially providing a pathway for hydrocarbons to migrate from zones of higher pressure to lower pressure freshwater zones.

Additionally, the bond between the casing and cement can be compromised over the well's life, creating a "micro-annulus" (a space between the outer pipe wall and cement sheath) that allows vertical migration of hydrocarbons along the outside of the pipe wall. [364,365] Micro-annulus' can be formed during initial

[363] Curran, E., Corrosion Control in Gas Pipelines, Coating Protection Provides a Lifetime of Prevention, Pipeline & Gas Journal, October 2007.

[364] See Ravi, K. (Halliburton), Bosma, M. (Shell) and Gastebled, O. (TNO Building and Construction Research), Safe and Economic Gas Wells through Cement Design for the Life of the Well, Society of Petroleum Engineering Paper No. 75700, 2002. Ravi et. al. concludes: "The extreme operating conditions that occur in gas-storage and gas-producing wells could cause the cement sheath to fail, resulting in fluid migration through the annulus…The sustained casing pressure observed on a number of wells after they have been put on production emphasizes the need to design a cement sheath that will maintain integrity during the life of the well…However, recent experience has shown that after well operations such as completing, pressure testing, injecting, stimulating and producing, the cement sheath could lose its ability to provide zonal isolation. This failure can create a path for formation fluids to enter the annulus, which pressurizes the well and renders the well unsafe to operate…Failure of the cement sheath is most often caused by pressure – or temperature-induced stresses inherent in well operations during the well's economic life."

cementing, or later in the well's life, due to: pipe wall thinning; cement deterioration; the shock of additional well workover activities (perforations, stimulation, drilling); pressure and temperature changes in the well; or by seismic vibrations.

In January 2011, NYS' consultant, Alpha Geoscience, recommended that NYSDEC ignore HCLLC's best practice recommendations for corrosion and erosion, citing Section 6.1.4.2 and 6.1.5.1 of the 2009 DSGEIS. In these sections, another NYS consultant (ICF) estimated the risk of groundwater contamination due to casing failure in a Class II injection well is 1 in 50 million wells.[366] Alpha Geoscience concludes that corrosion and erosion prevention, monitoring, and repair requirements are unnecessary in the NYCRR.

Neither Alpha Geoscience nor ICF provide technical justification for the use of a Class II injection well corrosion risk analysis as a surrogate for a gas well corrosion risk analysis. A Class II injection well risk profile is different than a gas well. Gas wells can continuously produce sources of corrosive gas (CO_2 and H_2S), water, and sediment, that can corrode and erode well casing and surface piping over time.

Neither Alpha Geoscience nor ICF examined:

- The full life cycle of a gas well, and the fact that there is substantial field evidence that well casings do corrode and erode over time;
- The fact that casing inspection logs, caliper logs, temperature surveys, and other wellbore diagnostics are commonly run to examine the well casing condition due to the known problem of gas well corrosion;
- Information on the amount of money spent annually on corrosion inhibitors, pipe coating, and other preventive measures to mitigate corrosion impacts;
- The fact that well service specialists routinely provide well casing patching, repair, and replacement services,[367] because gas well casing failure is a known problem; and,
- The fact that it is best practice to examine the condition of well casing over the well life to verify its integrity, especially before major well work (e.g. additional drilling, stimulation) is completed on an aging well.[368]

Additionally, Alpha Geoscience criticizes HCLLC for citing industry literature on corrosion best practices, stating that HCLLC's inclusion of this material shows industry bias. HCLLC disagrees with Alpha Geoscience's conclusion. Industry has developed most of the technology to address the problem; therefore, it is logical to cite industry literature on this point.

[365] See Stewart, R.B. and Schouten, F.C. (Shell), Gas Invasion and Migration in Cemented Annuli: Causes and Cures, Society of Petroleum Engineering Paper No. 14779, SPE Drilling Engineering, March 1988. Stewart and Schouten conclude: "*Gas migration resulting from casing contraction is a common field problem… Annular gas-migration problems can develop in an old well owing to changes in pressure or thermal conditions in the well.*"

[366] Alpha Geoscience, Review of the dSGEIS and Identification of Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 18.

[367] Storaune, A., Winters, W.J. (BP America Inc.), Versatile Expandables Technology for Casing Repair, Society of Petroleum Engineers, SPE Paper No. 92330-MS, SPE/IADC Drilling Conference, 23-25 February 2005, Amsterdam, Netherlands, 2005, p.1.

[368] Brondel, D., Edwards, R., Hayman, A., Hill, D., Shreekant, M., Semerad, T., Corrosion in the Oil Industry, Oilfield Review, April 1994, p. 9-10.

Experienced engineers know the importance of assessing and implementing programs to mitigate corrosion/erosion risk early in the field/well lifecycle. Corrosion of gas production equipment is a fundamental concern for the oil and gas industry that has been identified for decades.

> ***Failures of equipment handling or producing natural gas occur only in the absence of an adequate corrosion-control program.*** ***A successful program is shown to include (1) anticipation of corrosion in design factors of all equipment, (2) detection of corrosion within the system and measurement of its severity for future reference, (3) use of mitigation measures and (4) continual follow-up and adjustment of control techniques.*** *Design factors to be considered are tubing couplings, packers, tubing grade and size, and the number of tubing strings to be set.* ***Future corrosion problems and mitigation work should be recognized at the time the well completion is made so that the best possible design factors can be realized. Corrosion can be detected by gas analysis, water analysis, coupon exposures and caliper surveys.*** ***Quantitative data are needed to determine the severity of the problem and to design a suitable program of alleviation of the corrosion.*** *Use of inhibitors and plastic coatings are popular methods for mitigation of corrosion. Both methods have advantages and disadvantages that must be realized and evaluated. Control limits for a mitigation program should be established so that the operator can be certain that he is receiving the desired protection.* ***Gas gathering and process equipment also often suffer from corrosion….***
>
> *It is suggested that an adequate corrosion-control program must include efforts at various levels of company operations. All engineers and supervisors must participate actively in the corrosion-control effort.* ***As a property is being developed, corrosion control should be considered when the equipment to be used is being selected. When development is complete, the operating people must determine the seriousness of their corrosion problems. They must realize that the corrosion attack may change with changes in production characteristics and that absence of corrosion today does not guarantee absence of corrosion tomorrow. When corrosion is detected within an operation, mitigation is in order*** *[emphasis added].*[369]

Because of the known problem of casing corrosion, the National Association of Corrosion Engineers (NACE) developed Recommended Practice RP0186 to mitigate external casing corrosion; this standard applies to the design of cathodic protection for external surfaces of steel well casings, and would be used when soil/subsurface reservoir conditions present a corrosive environment warranting installation of cathodic protection system installation.[370]

NACE International writes:

> *Oil and gas wells represent a large capital investment.* ***It is imperative that corrosion of well casings be controlled to prevent loss of oil and gas, environmental damage, and personnel hazards, and in order to ensure economical depletion of oil and gas reserves necessary*** *[emphasis added].*[371]

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369 Fincher, D.R. (Tidewater Oil Co.), Corrosion in Gas Wells and Gas Gathering Systems, Journal of Petroleum Technology, Volume 13, Number 9, September 1961, Abstract.

370 NACE International Standard RP0186-2001, Application of Cathodic Protection for External Surfaces of Steel Well Casings.

371 NACE International, Application of Cathodic Protection for External Surfaces of Steel Well Casings, RP0186-2001, 2001, p.1.

Gas operators stress the importance of corrosion monitoring and control programs. For example, OMV Exploration and Production writes:

> ***Corrosion remains a key issue in petroleum production***. *Its continued occurrence has consequences on the safety of people and environment and the integrity of facilities and affects the economy of the oil or gas field. Particularly the presence of severe environments containing corrosive components such as carbon dioxide and hydrogen sulphide poses serious problems.* ***A central element in the design of facilities and the corrosion control is therefore the proper choice of materials which are both economical and provide a satisfactory performance over the entire service life with respect to the given environment. Prior to the production phase reliable corrosion monitoring programmes have to be selected, established, and implemented, as necessary*** *[emphasis added].*[372]

The magnitude and complexity of a corrosion/erosion mitigation program will vary depending on site-specific conditions. The important step is to complete the initial evaluation, assess the site-specific circumstances, and develop an adequate corrosion/erosion mitigation plan. Some mitigation programs are started early, some are applied intermittently, and others are instituted later in the gas production process; in all cases, an engineering assessment prior to gas drilling and production must be completed to determine the optimal plan.

The corrosion engineering textbook, Corrosion Control in Oil and Gas Production, explains the importance of developing a site-specific plan:

> ***The many possible alternatives available today for corrosion management for gas and oil well environments, dictates the need for a thorough evaluation and development of long term plans to assure a safe, economical and effective program***. *History has shown that both corrosion inhibition and corrosion resistant alloys (CRAs) have been used successfully in tough environments. The final decision on which method to use is often made on the basis of available capital versus long term operating costs [emphasis added].* [373]

The 2011 RDSGEIS: The 2011 RDSGEIS includes a substantially improved well casing program, including a three-casing-string design. However, this casing is typically made of carbon steel, and must be protected from corrosion and erosion. Chromium steel and corrosion resistant alloys are commonly installed in corrosive environments; however, these metals are substantially more expensive and are not currently proposed for NYS.

Well casing, once installed and cemented into place, will remain in the well for its entire lifecycle, and is often abandoned in place.[374] Therefore, it is in the operator's best economic interest to ensure that its casing investment is protected from corrosion and erosion.

[372] Oberndorfer, M. (OMV Exploration and Production), Corrosion Control in the Oil and Gas Production-5 Successful Case Histories, CORROSION Conference 2007, March 11-15, 2007, Nashville Tennessee, NACE International, 2007, p.1.

[373] Treseder, R.S., Tuttle, R.N., Corrosion Control in Oil and Gas Production, Chapter 14, Corrosion of Steels in Gas Wells, 1998.

[374] In some circumstances corroded casing will be pulled from a well prior to abandonment, although this process can prove difficult, time consuming, and expensive for fully cemented casing strings.

It would be shortsighted for NYS to require a robust well casing program, and not build in a corrosion and erosion control program. Chemicals, metallurgy, monitoring, and repair techniques are available to the operator to manage corrosion and erosion downhole (in the well) and at its surface facilities (e.g. corrosion inhibitors, cathodic protection systems, coatings).

Tools that can be used to monitor well corrosion include caliper tools and casing inspection logs. A caliper tool is run down the inside of the well casing or tubing to measure the internal diameter and assess metal wall loss. Casing inspection logs use ultrasonic and magnetic-flux technology to estimate metal wall loss. Additionally, temperature surveys can be run to look for gas cooling anomalies in the well, which are an indication of casing holes.[375]

NYSDEC has proposed cement evaluation tools to be run when HVHF wells are initially drilled and completed, which is a best practice. Cement integrity should also be monitored periodically over the well's life if casing corrosion occurs. Casing corrosion is an indicator of potential cement deterioration, as explained above.

Without regulations, the decision to invest in corrosion/erosion mitigation and wellbore integrity monitoring is left to the operator. In some cases, operators postpone mitigation to improve early economics. Deferral strategies can produce unfavorable results in the long-term, but may be attractive to small operators that have limited funds, or to large operators that plan to reap the benefits of early production and sell assets soon thereafter. Operators may not implement, unless required, long-term monitoring when faced with declining production, lower profits and when operating cost cuts are sought.

Corrosion and erosion programs that are instituted early can prolong the life of equipment and well casings, and reduce environmental risk. Delayed attention to corrosion and erosion mitigation can result in increased safety, environmental, and human health risks.

Gas well corrosion and erosion can occur in many ways:

- Oxygen contaminated drilling fluids are injected downhole, and can corrode well casing and drilling equipment;
- Water produced along with gas can corrode well casing, tubing, and downhole equipment;
- Acid stimulation treatments, used alone or in conjunction with hydraulic fracturing, readily attack metal;
- Well casing and surface piping can be eroded by high gas production velocities, especially when laden with sediment, sands, or hydraulic fracturing proppants;
- Corrosive soils can cause external corrosion of carbon steel casing;
- Hydrogen sulfide and carbon dioxide, often present in gas production, can corrode carbon steel; and
- Higher wellbore temperatures, increased velocity, and increased salinity accelerate corrosion rates.

NYCRR Proposed Revisions: NYSDEC has not proposed any new requirements for corrosion or erosion mitigation for the Marcellus, Utica, or other low-permeability reservoirs. There are no requirements for corrosion or erosion mitigation or long-term well integrity monitoring in the existing NYCRR.

[375] Pennsylvania Governor's Marcellus Shale Advisory Commission Report, July 22, 2011, recommends pressure testing each casing to ensure initial integrity of casing design and cement, and pressure testing and logging to verify the mechanical integrity of the casing and cement over the life of the well, p. 109.

Recommendation No. 99: Best corrosion and erosion mitigation practices and long-term well integrity monitoring should be included in the SGEIS and codified in the NYCRR. Operators should be required to design equipment to prevent corrosion and erosion. Corrosion and erosion monitoring, repair, and replacement programs should be instituted.

24. Well Control & Emergency Response Capability

Background: In 2009, HCLLC recommended that NYSDEC require an operator to have an Emergency Response Plan (ERP) and a well blowout control plan. HCLLC recommended that operators be required to demonstrate that they have access to sufficient personnel and resources to respond to a fire, explosion, blowout, or other industrial accident. Best practices include: developing response and well control plans; verifying there are a sufficient number of trained and qualified personnel to carry out the plans; ensuring operators have access to the necessary response equipment; and testing (drills and exercises) the plan prior to drilling.

In 2009, HCLLC also recommended that NYSDEC examine the capacity of local emergency response teams. Oil and gas industry accidents often require highly specialized response capability and equipment. Operators should be required to supplement local emergency response resources to meet this need.

In January 2011, NYS' consultant, Alpha Geoscience, concluded that NYS well control and emergency response planning requirements are narrowly focused on the Bass Island Trend wells. Alpha Geoscience agreed with HCLLC that new regulations are needed for the formations proposed for development under this SGEIS.[376]

The 2011 RDSGEIS: The 2011 RDSGEIS includes a new section (Section 7.13) on Emergency Response Plans, which is a substantial improvement. Section 7.13 states:

> *7.13 Emergency Response Plan*
>
> *There is always a risk that despite all precautions, non-routine incidents may occur during oil and gas exploration and development activities.* ***An Emergency Response Plan (ERP) describes how the operator of the site will respond in emergency situations which may occur at the site.*** *The procedures outlined in the ERP are intended to provide for the protection of lives, property, and natural resources through appropriate advance planning and the use of company and community assets.* ***The Department proposes to require supplementary permit conditions for high-volume hydraulic fracturing that would include a requirement that the operator provide the Department with an ERP consistent with the SGEIS at least 3 days prior to well spud.*** *The ERP would also indicate that the operator or operator's designated representative will be on site during drilling and/or completion operations including hydraulic fracturing, and such person or personnel would have a current well control certification from an accredited training program that is acceptable to the Department [emphasis added].*
>
> *The ERP, at a minimum, would also include the following elements:*
>
> - *Identity of a knowledgeable and qualified individual with the authority to respond to emergency situations and implement the ERP;*
> - *Site name, type, location (include copy of 7 ½ minute USGS map), and operator information;*
> - *Emergency notification and reporting (including a list of emergency contact numbers for the area in which the well site is located; and appropriate Regional*

[376] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 42.

Minerals' Office), equipment, key personnel, first responders, hospitals, and evacuation plan;

- *Identification and evaluation of potential release, fire and explosion hazards;*
- *Description of release, fire, and explosion prevention procedures and equipment;*
- *Implementation plans for shut down, containment and disposal;*
- *Site training, exercises, drills, and meeting logs; and*
- *Security measures, including signage, lighting, fencing and supervision.*[377]

Appendix 6, Proposed Environmental Assessment Form Addendum, requires an Emergency Response Plan be located at the rig, and that the plan be followed. [378]

Appendix 10, Proposed Supplementary Permit Conditions for HVHF, Condition No. 2, requires an ERP be provided 3 days prior to spud and available at the site. Condition No. 2 requires the ERP be developed in a manner consistent with the SGEIS, but it does not reference the Chapter 7.13 minimum requirements.

> *An emergency response plan (ERP) consistent with the SGEIS must be prepared by the well operator and be available on-site during any operation from well spud (i.e., first instance of driving pipe or drilling) through well completion. A list of emergency contact numbers for the area in which the well site is located must be included in the ERP and the list must be prominently displayed at the well site during operations conducted under this permit. Further, a copy of the ERP in electronic form must be provided to this office at least 3 days prior to well spud.* [379]

The addition of an Emergency Response requirement to the SGEIS is a substantial improvement. However, it is recommended that NYSDEC include a review, approval, and audit process to ensure that quality plans are developed. NYSDEC should have a program to audit ERPs via drills, exercises, equipment inspections, and personnel training audits.

As proposed by NYSDEC, the operator is required to submit an ERP three days prior to commencing drilling. This leaves no time for regulators to review and approve the ERP. NYSDEC proposes no process for determining the adequacy of the ERP. There is no assessment of personnel training and qualifications, equipment resources, or local emergency response services.

Industrial fires, explosions, blowouts, and spills require specialized emergency response equipment, which may not be available at local fire and emergency services departments. For example, local fire and emergency services departments typically do not have well capping and control systems.

Larger, paid fire and emergency services departments, located near existing industrial developments, may have some industrial firefighting capability; however, the level of capability should be assessed by the operator and supplemented. If local emergency response services are relied upon in the ERP, operators should ensure emergency response personnel are trained, qualified, and equipped to respond to oil and gas industrial accidents. Small, local, volunteer fire and emergency services departments will typically not be equipped or qualified to meet this need.

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[377] 2011 NYSDEC, RDSGEIS, Page 7-146.

[378] 2011 NYSDEC, RDSGEIS, Appendix 6, Page A6-7.

[379] 2011 NYSDEC, RDSGEIS, Appendix 10, Page 1 of 17.

Recommendation No. 100: NYSDEC should identify an Emergency Response Plan (ERP) review, approval, and audit process to ensure that quality plans are developed. Objectives of the ERP should include adequately trained and qualified personnel, and the availability of adequate equipment. If local emergency response resources are relied on in the ERP, operators should ensure they are trained, qualified, and equipped to respond to an industrial accident. Additionally, NYSDEC should have a program to audit ERPs via drills, exercises, equipment inspections, and personnel training audits.

On average, a blowout occurs in 7 out of every 1,000 onshore exploration wells.[380] This risk statistic is applicable to Marcellus and other low-permeability gas reservoir drilling that is still in the exploration and appraisal phase in NYS. Blowout rates are less frequent for production wells where more information is known about the reservoir, well control is optimized, and personnel are more experienced in site-specific conditions. For example, a review of production well blowouts in California estimated 1 blowout per 2,500 wells drilled.[381] California's data showed that: 25% of the blowouts affected more than 25 acres; the average blowout lasted 18 hours; and the maximum blowout length was 6 months.

Using the California statistic of 1 blowout per 2,500 production wells drilled (which is more conservative than the exploration well statistic of 7 blowouts per 1,000 exploration wells), and NYS' estimate of 1600 wells per year over 30 years, an incremental likelihood of 19 blowouts is estimated for NYS.[382] Because some of the early wells drilled will be exploration wells, the blowout frequency many be higher in the first few years of shale gas development in NYS and it is plausible that 40[383] or more well blowouts could occur during the next 30 years. Therefore, blowouts are a reasonably foreseeable significant impact, and mitigation is warranted.

Hydrocarbon reservoirs can contain large quantities of gas and formation water, which can be released into the surrounding environment during a well blowout, resulting in significant damage. For example, the Chesapeake Energy 2011 Marcellus well blowout in Bradford County, Pennsylvania spilled thousands of gallons of fracture treatment fluid over "containment walls, through fields, personal property and farms, even where cattle continue[d] to graze."[384]

Methods to control a gas well blowout can require significant water withdrawals – from 500,000 to 6,000,000 gallons per day. Well control experts may also use foam and dry chemicals to respond to a blowout. Controlling a well blowout can create large volumes of waste. Rig-deluge operations create large pools of water that can transport oil, chemicals, fuels, and other materials toward lower elevation drainage areas.

In addition to the Chesapeake Energy 2011 well blowout, another Pennsylvania Marcellus Shale blowout occurred in 2010.[385,386] Also, in 2010, there was a major industrial fire. The 2010 incidents prompted

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380 Rana, S., Environmental Risks- Oil and Gas Operations Reducing Compliance Cost Using Smarter Technologies, Society of Petroleum Engineering Paper 121595-MS, Asia Pacific Health, Safety, Security and Environment Conference, 4-6 August 2009, Jakarta, Indonesia, 2009.

381 Jordan, P.D., and Benson, S. M., Well Blowout Rates in California Oil and Gas District 4- Update and Trends, Summary of Well Blowout Risks for California Oil and Gas District 4, 1991-2005, Table 1

382 19 blowouts= (1,600 wells drilled per year)(30 years)(1 blowout per 2500 wells drilled).

383 40 blowouts= 1,600 wells drilled per year)(2 years)(7 blowout per 1000 wells drilled)+(1,600 wells drilled per year)(28 years)(1 blowout per 2500 wells drilled).

384 Pennsylvania Fracking Spill: Natural Gas Well Blowout Spills Thousands of Gallons of Drilling Fluid, The Huffington Post, April 20, 2011.

385 Blowout Occurs at Pennsylvania Gas Well, Wall Street Journal, June 4, 2010.

Pennsylvania to realize the need for its own emergency response services, with trained and qualified personnel and adequate equipment available 24 hours per day, 7 days per week. The news reported that it took “16 hours for out-of-state crews to address a June 3 blowout in Clearfield County and 11 hours to extinguish a July 23 fire in Allegheny County. In both cases, well operators had to wait for response crews to fly in from Texas.”[387]

In 2010, CUDD Well Control located a new facility in Canton Township, Bradford County, Pennsylvania. Canton Township is located near the southern NYS border. It may be possible for NYS operators to contract with CUDD to provide emergency response services. However, a better alternative may be for NYS to collaborate with a well control specialist to provide more centrally located services dedicated to supporting NYS’ proposed drilling activity.

The 2011 RDSGEIS requires operators to develop and implement a blowout preventer (BOP) testing program. However, the SGEIS does not unequivocally require a well control expert be on contract. It is recommended that NYSDEC require operators to have a contract in place for immediate response by a trained and qualified well control contractor. If a contract with a well control expert is not in place when a blowout occurs, contract negotiations can cause detrimental delays.

Well capping is a proven, effective, and rapid method to control a blowout. Well control contractors provide the expertise and equipment for this operation. However, in some limited cases, well capping is not effective, and a relief well may be required. Therefore, it is important for operators to also have prearranged access to a relief well rig, either via a contract with a rig provider or via a memorandum of agreement to provide emergency response assistance with a nearby operator.

Recommendation No. 101: NYSDEC should require a well blowout response plan (either included in the Emergency Response Plan or as a separate plan), a contract retainer with an emergency well control expert, and prearranged access to a relief well rig.

NYCRR Proposed Revisions: NYSDEC has proposed a new regulation at 6 NYCRR § 560.5 requiring an ERP for HVHF wells. This is a substantial improvement; however, this plan should be required for all wells in NYS, not just HVHF wells. Additionally, the NYCRR should more clearly specify the ERP content requirements and include the recommendations listed above.

Recommendation No. 102: The requirement for an Emergency Response Plan should be codified in the NYCRR. It should apply to all wells in NYS, not just HVHF wells. The NYCRR should specify ERP content requirements. These requirements should be consistent with NYSDEC’s recommendations listed in Chapter 7.13 of the 2011 RDSGEIS.

[386] Pennsylvania Fracking Spill: Natural Gas Well Blowout Spills Thousands of Gallons of Drilling Fluid, The Huffington Post, April 20, 2011.

[387] http://pagasdrilling.com/tag/cudd-well-control/

25. Financial Assurance Amount

Background: In December 15, 2008, scoping comments to NYSDEC, NRDC, and its co-signatories requested the DSGEIS examine whether NYSDEC requires a sufficient financial assurance amount (in the form of a bond or other financial instrument). In its comments on the 2009 DSGEIS, NRDC and its co-signatories, as well as HCLLC, noted that the DSGEIS did not provide an analysis of the current financial assurance requirements, and requested that work be done.

HCLLC recommended that the SGEIS examine financial assurance amounts to ensure there is funding available to properly plug and abandon wells; remove equipment and contamination; complete surface restoration; and provide adequate insurance to compensate nearby public for adverse impacts (e.g., well contamination).

Long horizontal wells are more costly to plug and abandon than vertical wells. Also, surface impacts are increased when high-volume fracture stimulation treatments are employed and multiple wells are drilled from a single well pad. Both of these operations require additional gas treatment and transportation facilities.

In January 2011, NYS' consultant, Alpha Geoscience, advised NYSDEC to ignore financial assurance recommendations, declaring it "out of scope" of the SGEIS, because legislative action would be required at ECL 23-0305(8)(k).[388] HCLCC disagrees. Regardless of whether a legislative change is required, financial assurance improvements for Marcellus Shale gas well drilling should not be disregarded in the RDSGEIS; instead, the SGEIS should recommend to NYS' Legislature the need for legislative action as a mitigating measure.

The 2011 RDSGEIS: The 2011 RDSGEIS still does not include recommendations for increasing the financial assurance amounts for HVHF shale gas operations.

NYCRR Proposed Revisions: There is no proposed revision to the amount of financial security for wells up to 6,000' deep. 6 NYCRR § 551.5. For wells between 2,500' and 6,000' in depth, NYSDEC requires only $5,000 financial security per well, with the overall total per operator not to exceed $150,000.

For wells drilled more than 6,000' deep, NYSDEC is proposing a regulatory revision that requires the operator to provide financial security in an amount based on the anticipated cost for plugging and abandoning the well (6 NYCRR § 551.6).

In 2003, ICF completed a report for the New York State Energy Research and Development Authority (NYSERDA) on NYS oil and gas wells.[389] ICF's report advised NYS that well plugging and abandonment can range from $5,000 per well to more than $50,000 per well depending on the well depth, well condition, site access, and site condition.[390] ICF's 2003 report recommended that NYS consider increased financial security requirements. NYSDEC's current requirement of only $5,000 financial

[388] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011, Page 46.

[389] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003. This report is found at http://esogis.nysm.nysed.gov/esogisdata/downloads/NYSERDA/7012.pdf. The report is listed as a draft, and a final could not be located on the world-wide web.

[390] ICF Consulting, Well Characterization and Evaluation Program for New York State Oil and Gas Wells, Draft Report for the New York State Energy Research and Development Authority, PSA No. 7012, July 2003, Page. ES-1.

security per well is clearly insufficient, if ICF determined in 2003 that the cost could be as much as $50,000 per well. Today's cost would likely be higher, almost a decade later.

In Ohio, an operator is required to obtain liability insurance coverage of at least $1,000,000 and up to $3,000,000 for wells in urban areas. The Ohio Code at Title 15, Chapter 1509 requires:

> ***1509.07 Liability insurance coverage.*** ***An owner of any well****, except an exempt Mississippian well or an exempt domestic well,* ***shall obtain liability insurance coverage*** *from a company authorized to do business in this state* ***in an amount of not less than one million dollars bodily injury coverage and property damage coverage to pay damages for injury to persons or damage to property caused by the drilling, operation, or plugging of all the owner's wells in this state.*** *However,* ***if any well is located within an urbanized area, the owner shall obtain liability insurance coverage in an amount of not less than three million dollars for bodily injury coverage and property damage coverage to pay damages for injury to persons or damage to property caused by the drilling, operation, or plugging of all of the owner's wells in this state****. The owner shall maintain the coverage until all the owner's wells are plugged and abandoned or are transferred to an owner who has obtained insurance as required under this section and who is not under a notice of material and substantial violation or under a suspension order. The owner shall provide proof of liability insurance coverage to the chief of the division of oil and gas resources management upon request. Upon failure of the owner to provide that proof when requested, the chief may order the suspension of any outstanding permits and operations of the owner until the owner provides proof of the required insurance coverage.[emphasis added]*
>
> *Except as otherwise provided in this section, an owner of any well, before being issued a permit under section 1509.06 of the Revised Code or before operating or producing from a well, shall execute and file with the division of oil and gas resources management a surety bond conditioned on compliance with the restoration requirements of section 1509.072, the plugging requirements of section 1509.12, the permit provisions of section 1509.13 of the Revised Code, and all rules and orders of the chief relating thereto, in an amount set by rule of the chief.*

Recommendation No. 103: NYSDEC's financial assurance requirements should not narrowly focus on the cost for plugging and abandoning a well. Instead, NYSDEC's financial assurance requirements should include a combination of bonding and insurance that addresses the costs and risks of long-term monitoring; publicly incurred response and cleanup operations; site remediation and well abandonment; and adequate compensation to the public for adverse impacts (e.g., water well contamination). Recommendations for financial assurance improvements for Marcellus Shale gas well drilling should be included in the SGEIS as a mitigating measure, even if legislative action is ultimately required. Additionally, improved financial assurance should be codified in the NYCRR during this revision to the extent possible.

By comparison, Fort Worth, Texas requires an operator drilling 1-5 wells to provide a blanket bond or letter of credit of at least $150,000, with incremental increases of $50,000 for each additional well.[391] Therefore, under Fort Worth, Texas requirements, an operator drilling 100 wells would be required to hold a bond of $4,900,000, as compared to $150,000 in NYS.

[391] Fort Worth, Texas Ordinance No. 18449-2-2009, An Ordinance Amending the Code of Ordinances for the City of Fort Worth for Gas Drilling, 2009.

In addition to the bond amount, Fort Worth, Texas also requires the operator to carry multiple insurance policies:

1. *Standard Commercial General Liability Policy of at least $1,000,000 per occurrence. The Standard Commercial General Liability insurance must include: "premises, operations, blowout or explosion, products, completed operations, sudden and accidental pollution, blanket contractual liability, underground resources and equipment hazard damage, broad form property damage, independent contractors' protective liability and personal injury."*
2. *Excess or Umbrella Liability of $5,000,000;*
3. *Environmental Pollution Liability Coverage of at least $5,000,000 "applicable to bodily injury, property damage, including the loss of use of damaged property or of property that has not been physically injured or destroyed; cleanup costs; and defense, including costs and expenses incurred in the investigation, defense or settlement of claims…coverage shall apply to sudden and accidental, as well as gradual pollution conditions resulting from the escape or release of smoke, vapors, fumes, acids, alkalis, toxic chemicals, liquids or gases, waste material or other irritants, contaminants or pollutants."*
4. *Control of Well Policy of at least $5,000,000 per occurrence/combined single limit with a $500,000 sub-limit endorsement for damage to property for which the Operator has care, custody and control; and*
5. *Other insurance required by Texas (e.g. Workers Compensation Insurance, Auto Insurance, and other corporate insurance required to do business in the state of Texas).*[392]

Financial assurance requirements should be increased to address worst-case risk exposure. Risk assessments should include worst-case scenario financial impact models. The risk modeling should be used to set higher financial assurance requirements.

Recommendation No. 104: The financial assurance requirements at 6 NYCRR §§ 551.5 and 551.6 are insufficient to address the risks to NYS and private parties associated with oil and gas development. It is recommended that each operator provide a bond of at least $100,000 per well, with a cap of $5,000,000 for each operator. Additionally, NYSDEC should require Commercial General Liability Insurance, including Excess Insurance, Environmental Pollution Liability Coverage, and a Well Control Policy, of at least $5,000,000. If NYSDEC deviates from these financial assurance requirements, it should be justified with a rigorous economic assessment that is provided to the public for review and comment.

[392] Fort Worth, Texas Ordinance No. 18449-2-2009, An Ordinance Amending the Code of Ordinances for the City of Fort Worth for Gas Drilling, 2009.

26. Seismic Data Collection

Background: In 2009, HCLLC recommended that NYSDEC improve the DSGEIS and establish regulatory requirements for seismic data collection to reduce impacts to the environment and the public. The 2009 DSGEIS addressed naturally occurring seismic events in Chapter 4, but was silent on the impacts from industrial seismic exploration, which is used to locate subsurface gas reservoirs including shale gas targets.

This problem persists in the 2011 RDSGEIS. The 2011 RDSGEIS discusses naturally occurring seismic events, and seismically induced fractures from HVHF operations, but does not include any analysis of the potential impacts or mitigation needed for two-dimensional (2D) or three-dimensional (3D) seismic surveys used to target hydrocarbon formations for exploration and appraisal drilling. These seismic surveys are also useful to identify major fault systems to be used in HVHF design and modeling. Improved understanding of the subsurface stratigraphy and fault systems will improved 3D model simulation predictions and can aid engineers in designing HVHF treatments that do not link induced fractures with existing, conductive, natural fault systems that could move HF fluids into protected groundwater resources or water wells.

In January 2011, NYS' consultant, Alpha Geoscience provided a misguided recommendation to NYSDEC to ignore seismic data collection mitigation in the RDSGEIS, as "irrelevant."[393] Because seismic data collection is typically the first step in unexplored areas, to locate and optimize exploration drilling targets, seismic data collection mitigation when used to target Marcellus Shale wells is hardly "irrelevant."

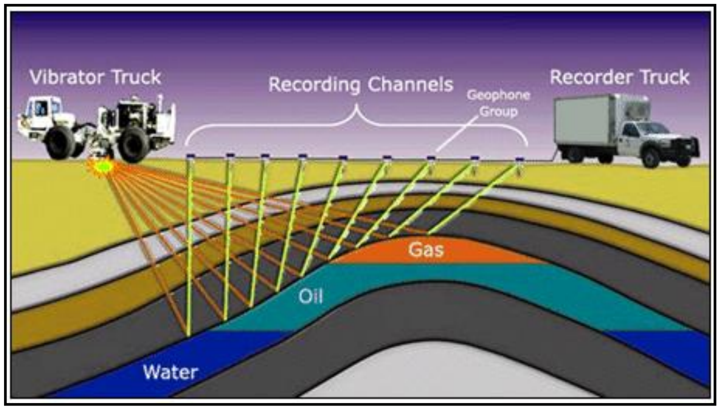
Therefore, it is unclear whether NYSDEC is not familiar with the use of seismic data collection to target hydrocarbon formations for drilling, and the mitigation measures needed because its consultants advised against study of this important mitigation, or whether shale gas operators have told NYSDEC that they don't intend to collect two-dimensional (2D) or three-dimensional (3D) seismic surveys prior to exploring in the Marcellus Shale.

If operators do not intend to collect additional 2D and 3D data, that representation should be stated in the RDSGEIS, and the 2D and 3D data collection should be precluded in NYS. Otherwise, the impacts of this work should be identified and mitigated. This is an important issue to resolve, because seismic surveys can create significant surface impacts and disruptions.

Recommendation No. 105: If 2D or 3D seismic surveys are planned, or are possible in the future, the NYCRR should codify a permitting process for these activities and institute mitigating measures in the SGEIS to minimize surface impacts and disruptions, and require rehabilitation of impacted areas.

Exploration for oil and natural gas typically begins with a geologic examination of the surface structure of the earth, to identify areas where petroleum or gas deposits might exist. Once a geologist/geophysicist has identified an area of potential interest based on surface geologic maps, seismic data collection is typically obtained to identify possible subsurface hydrocarbon traps and structures.

[393] Alpha Geoscience, Review of the dSGEIS and Identification Best Technology and Best Practices Recommendations, Harvey Consulting, LLC; December 28, 2009, prepared for NYSERDA, January 20, 2011.



Seismic exploration equipment is used to send seismic waves into the earth. Seismic waves are generated by a surface positioned source and are measured by a surface positioned receiver. The rate that seismic energy is transmitted and received through the earth crust provides information on the subsurface geology, because seismic waves reflect at different speeds and intensity off various rock strata and geologic structures. Collecting seismic data in this manner is called a Reflection Seismic Survey.[394]

A reflection seismic survey involves generating hundreds to tens of thousands of seismic source events, or shots, at various locations in the survey area. The seismic energy generated by each shot is detected and recorded by sensitive receivers ("geophones" on land and "hydrophones" under water) at a variety of distances from the source location. Geophones and hydrophones are connected by long cables to relay the collected information back to a centralized computer. The photo to the left is a geophone and cable system.[395]

For every source event, each geophone generates a seismogram or trace, which is a time series representing the earth movement at the receiver location. A record of all traces for each shot is transmitted to a computer for storage and conversion into a seamless cross-sectional representation of the subsurface for subsequent study and interpretation by a trained geophysicist.

Onland seismic operations involve generation of seismic vibrations by explosive energy sources or by mechanical sources. One type of energy source for seismic exploration is an explosive charge. Small holes ("shot-holes"), typically 4 inches in diameter are drilled into the earth surface, 10-60' deep depending on surface terrain.[396] Although, some drill holes have been drilled to 200'.[397] The photo to the right shows an example of a shot-hole drill unit.

[394] U.S. Geologic Survey, Seismic Data Acquisition.

[395] Geophone and cable photo from http://www.anr.state.vt.us/dec/geo/newbedu.htm, State of Vermont.

[396] Westlund, D., Thurber, M.W., Best Environmental Practices for Seismic Exploration in Tropical Rainforest, Society of Petroleum Engineers International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, SPE 10HSE 126844-PP, April 2010.

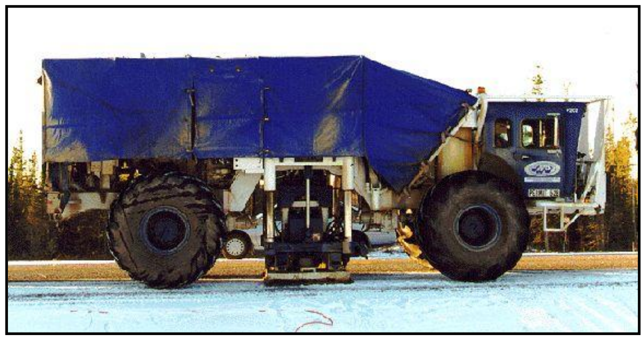
[397] US Fish and Wildlife Service, 612 FW 2, Oil and Gas, Policy Manual.

The hole must be drilled into a hard layer of soil that is sufficiently dense to carry the seismic wave.[398] Explosive charges (typically 5-50 pounds each)[399] are lowered into the hole and detonated to create a shock wave (vibration). Some states have limits on the size of charges that can be deployed near environmentally sensitive areas, human inhabitation and near roadways.

Historic use of explosives on the ground surface resulted in large craters and extensive surface damage. Explosive charges are no longer deployed at the surface. Instead, a shot-hole must be drilled and the explosive lowered into the shot-hole at a sufficient depth to prevent surface craters. Shot-holes are filled with cuttings, bentonite and rocks to minimize surface impact.

Mechanical vibrators are an alternative to the use of explosives, and are more commonly used. Mechanical vibrators provide more consistent source strength and repeatability, and they are more reliable in the case of repeat data acquisition programs or for time-lapse studies.

Mechanical vibrators can include: a pad that thumps the surface of the earth (“thumper trucks”), driven by gravity or compressed air; a truck that generates vibrations (“Vibroseis™ Truck”); and compressed air guns.[400] The photo to the right shows a Vibroseis Truck. The Vibroseis method involves a truck equipped with vibrator pads that are lowered to the ground and triggered. Depending on the subsurface target depth and the purpose of the seismic survey, two or more seismic Vibroseis Trucks (vibrating in sync) may be needed.



In cold climates, ice road construction and use of Vibroseis Trucks for seismic data acquisition is the norm. Seismic data is typically secured over the winter months along ice road routes, to reduce footprint and stress to sensitive areas of the tundra environment.

The use of thumper trucks is not considered best practice because it involves dropping a steel slab that weighs about three tons to the ground to create a seismic vibration. Thumper trucks are large, requiring extensive tree and vegetation removal, and leave land scars.

In areas where seismic data is collected in water, the energy source is usually compressed air in an airgun submerged underwater, because explosives can cause adverse impacts to aquatic life.

[398] The Pembina Institute, Seismic Exploration, www.pembina.org.

[399] US Fish and Wildlife Service, 612 FW 2, Oil and Gas, Policy Manual.

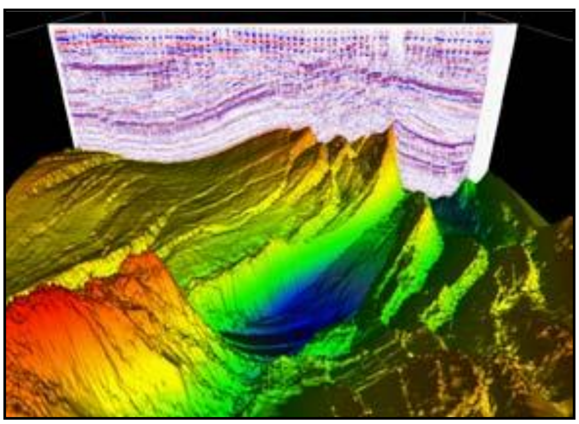
[400] Petroleum Engineering Handbook, Reservoir Engineering and Petrophysics, Volume V(A), Society of Petroleum Engineers, 2007.

Significant surface impacts can be caused by extensive tree and vegetation removal to create straight "cutlines" to run seismic equipment (as shown in the photo to the left). Lines need to be cut to run mechanical vibration equipment or set explosives to generate the seismic waves, and other seismic lines are cleared to set geophones to measure the seismic reflection. The width of each cutline depends on the seismic survey method used, but can be on the order of 20'-50' wide where large seismic equipment units are required. Best practice is to decrease the width of the cutlines to as small as possible using hand carried equipment. More recently companies have been able to reduce cutline width to 6'-10' in certain circumstances.

The spacing between each cutline is dependent on the type of seismic equipment used and depth of examination into the earth. The distance between each cutline is typically 300' apart (shallow reservoir targets) to 3,000' apart (deeper reservoir targets).[401]

Depending on existing development, infrastructure and access in the area planned for onshore seismic exploration, a seismic operator may need to build access roads, set up temporary camps and establish helicopter landings to bring in personnel and equipment. In areas where there are existing roads, housing and airports, surface disturbance can be minimized.

A basic set of seismic data can be obtained by setting a two dimensional array of seismic sources and receivers (2D seismic). Typically 2D seismic requires seismic lines tens of miles apart. Often 2D data is acquired along existing roads or access routes to minimize surface impacts. Along the 2D seismic cutlines shot-points and receivers are evenly spaced to send and receive a signal. This process produces a 2D slice of the subsurface.



If funding is available, operators generally opt to collect three dimensional seismic (3D seismic) images of the subsurface. 3D seismic data acquisition involves a much more intensive data collection effort, using multiple shot lines arranged perpendicular to multiple receiver lines of geophones, with seismic lines spaced several hundred feet apart, rather than miles apart.[402] An example of a map produced from a 3D seismic survey is shown to the left.

Seismic operations are very labor intensive and require large amounts of equipment, personnel and support systems. Depending on the size of the area under study, and the type of equipment selected, seismic operations can require dozens to hundreds of personnel. In addition to seismic exploration equipment, there is a need for housing, catering, waste management systems, water supplies, medical facilities, equipment maintenance and repair shops, and other logistical support functions. None of these impacts have been analyzed in the NYS RDSGEIS.

There are typically six different crews deployed: (1) access crews, that clear seismic lines, (2) "shooters" that drill the shot-holes and set the explosive charges or run the mechanical vibration equipment to generate seismic waves, (3) "recorders" that set the geophones and measure the seismic reflection, (4) the "pick-up" crews that move the equipment from one location to the next along the seismic lines,

[401] The Pembina Institute, Seismic Exploration, www.pembina.org.

[402] Westlund, D., Thurber, M.W., Best Environmental Practices for Seismic Exploration in Tropical Rainforest, Society of Petroleum Engineers International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, SPE 10HSE 126844-PP, April 2010.

(5) logistical support crews that provide housing, food, medical, maintenance and repair, and transportation; and (6) remediation and plugging crews that restore the area and plug shot-holes (if used).

> **Recommendation No. 106**: The increased industrial activity (e.g. economic impacts, noise, surface disturbance, wildlife impacts, etc.) associated with 2D and 3D seismic surveys should be examined in the SGEIS.

In 2011, HCLLC developed a report for NRDC and Sierra Club describing the types of impacts that occur from 2D and 3D seismic surveys, and made recommendations for best practices and model permit requirements. The recommendations in this report could be considered by NYSDEC in crafting seismic survey requirements for NYCRR.[403]

> **Recommendation No. 107**: Consider the best practices and model permit requirements proposed in Harvey Consulting, LLC., Onshore Seismic Exploration Best Practices & Model Permit Requirements Report to: Sierra Club and Natural Resources Defense Council, January 20, 2011, for inclusion as mitigation measures in the SGEIS and improvements in the NYCRR to regulate seismic survey data collection.

[403] Harvey Consulting, LLC., Onshore Seismic Exploration Best Practices & Model Permit Requirements Report to: Sierra Club and Natural Resources Defense Council, January 20, 2011.

APPENDIX A

Surface Casing Table

Appendix A - Surface Casing Table

Surface Casing Requirement	2011 RDSGEIS Appendix 8 Casing and Cementing Practices	2011 RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	2011 RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed Permit Conditions and Recommendations in 2011 RDSGEIS	NYCRR Requirements for all Wells, NYCRR Part 554	ADDITIONAL NYCRR Requirements for all HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Setting Depth	75' beyond the deepest fresh water zone encountered or 75' into competent rock (bedrock), whichever is deeper.	100' below the deepest freshwater zone and at least 100' into bedrock.	No requirement listed; assume it defaults to the Appendix 8 requirement of 75'.	The Appendix 10 HVHF surface casing setting depth requirement is less stringent than the Appendix 9 requirement; both should be 100'. NYSDEC should consider a 100' protection for all oil and gas wells. Additionally, NYSDEC needs to clarify whether the setting depth is intended to protect potable freshwater only, or include a broader definition of protected groundwater, which would result in deeper surface casing depths.	Surface casing must be run in all wells to extend below the deepest potable fresh water level. Neither the 75' nor the 100' setting depth below the deepest protected water zone is specified in the NYCRR.	No additional requirement.	NYSDEC should consider a 100' protection for all oil and gas wells. Additionally, NYSDEC needs to clarify whether this setting depth is intended to protect potable freshwater only, or include a broader definition of protected groundwater, which would result in deeper surface casing depths. This requirement should apply to all NYS wells.
Protected water depth estimate and verification	No requirement.	Estimated in drilling application and verified while drilling.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method. If the actual protected water depth extends beyond the estimated protected water depth, an additional string of intermediate casing should be required.	No requirement.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method. If the actual protected water depth extends beyond the estimated protected water depth, an additional string of intermediate casing should be required. This requirement should apply to all NYS wells.
Cement Sheath Width	No requirement.	At least 1-1/4".	No requirement.	A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed on all oil and gas wells. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells.

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Amount of Cement in Annulus	Not specified, but it is presumed that the goal is to complete annulus cementing, because the requirements include 25% excess cement; however, the conditions require a reporting of the cement top location, if cement is not returned to the surface, which indicates that NYSDEC could accept a partially cemented annulus.	Entire annulus must be cemented; cement squeeze may be required.	No requirement listed; assume it defaults to Appendix 8 requirement.	The surface casing annulus should be completely filled with cement; this should be clearly specified. There should be no void space in the annulus.	There is a requirement to circulate cement to the top of the hole.	No additional requirement.	The surface casing annulus should be completely filled with cement; this should be clearly specified. There should be no void space in the annulus. This requirement should apply to all NYS wells.
Shallow gas hazards	Surface hole drilling must stop and surface casing must be set and cemented before drilling deeper into hydrocarbon resources.	The likelihood of shallow gas hazards must be estimated in the drilling application and verified while drilling.	No requirement listed; assume it defaults to Appendix 8 requirement.	All oil and gas well designs and applications should plan for shallow gas hazards. Any shallow gas hazards encountered while drilling should be recorded. If a shallow gas hazard is encountered, surface casing should be set and cemented to protect water resources, before drilling deeper into hydrocarbon resources.	No requirement.	No requirement.	If a shallow gas hazard is encountered, surface hole drilling must stop, and surface casing must be set and cemented, before drilling deeper into hydrocarbon resources. All oil and gas well designs and applications should plan for shallow gas hazards. Any shallow gas hazards encountered while drilling should be recorded. This requirement should apply to all NYS wells.
Excess Cement Requirement	25%	50%	No requirement listed; assume it defaults to Appendix 8 requirement of 25%.	25% excess cement is standard practice, unless a caliper log is run to more accurately assess hole shape and required cement volume.	No requirement.	No requirement.	25% excess cement is standard practice, unless a caliper log is run to more accurately assess hole shape and required cement volume. This requirement should apply to all NYS wells.

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Cement Type	The cement slurry shall be prepared according to the manufacturer's or contractor's specifications to minimize free water content in the cement.	No requirement listed; assume it defaults to Appendix 8 requirement.	The cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive.	HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) is best practice. These practices should apply to all wells, not just HVHF wells.	No requirement.	The cement must conform to the industry standards specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content and contain a gas-block additive.	The cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) is best practice. These practices should apply to all wells, not just HVHF wells.
Cement Mix Water Temperature and pH Monitoring	Required.	No requirement listed; assume it defaults to Appendix 8 requirement.	No requirement listed; assume it defaults to Appendix 8 requirement.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations.	No requirement.	The cement must conform to the industry standards specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. This requirement should apply to all NYS wells, not just HVHF wells.
Lost Circulation Control	Required.	Required.	Required.	Lost circulation control is best practice.	No requirement.	No requirement.	Lost circulation control is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

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Spacer Fluids	Required.	No requirement listed; assume it defaults to Appendix 8 requirement.	Required.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells, not just HVHF wells.
Hole conditioning before cementing	Gas flows must be killed or lost circulation must be controlled and the hole be conditioned before cementing.	No requirement listed; assume it defaults to Appendix 8 requirement.	No requirement listed; assume it defaults to Appendix 8 requirement.	Hole conditioning before cementing is best practice.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.
Cement Installation and Pump Rate	No requirement.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice; this requirement should apply to all oil and gas wells, not just HVHF wells.	No requirement.	Cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice; this requirement should apply to all oil and gas wells, not just HVHF wells.
Rotating and Reciprocating Casing While Cementing	No requirement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement.	No requirement.	No additional requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.
Centralizers	At least every 120', with a minimum of two centralizers. A table of centralizer-hole size combinations is included.	At least every 120'.	At least two centralizers (one in the middle and one at the top), and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002).	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API RP 10D-2 (July 2010).	No requirement.	In addition to centralizers otherwise required by the department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed, and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill.	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API RP 10D-2 (July 2010). This requirement should apply to all NYS wells, not just HVHF wells.

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Casing quality	All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi); used casing may be approved for use, but must be pressure tested before drilling out the casing shoe.	New pipe with minimum internal yield pressure (MIYP) of 1,800 psi, or reconditioned pipe that has been tested internally to a minimum of 2,700 psi, must be used.	New pipe is required and must conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002).	New casing should be used in all wells. Once installed, surface casing remains in the well for the life of the well, and typically remains in place when the well is plugged and abandoned. It is important that the surface casing piping string (known as "the water protection piping string") is of high quality to maximize the corrosion allowance and life-cycle of the piping. The installation of older, used, thinner pipe, with less remaining corrosion allowance, may be a temporary solution, but not a long-term investment in groundwater protection. Used piping may pass an initial pressure test; however, it will not last as long as new piping, and will not be as protective of water resources in the long-term.	No requirement.	All casing must be new and conform to the industry standards specified in the permit to drill.	New casing should be used in all wells. Once installed, surface casing remains in the well for the life of the well, and typically remains in place when the well is plugged and abandoned. It is important that the surface casing piping string (known as "the water protection piping string") is of high quality to maximize the corrosion allowance and life-cycle of the piping. The installation of older, used, thinner pipe, with less remaining corrosion allowance, may be a temporary solution, but not a long-term investment in groundwater protection. Used piping may pass an initial pressure test; however, it will not last as long as new piping, and will not be as protective of water resources in the long-term.
Casing Thread Compound	No requirement.	No requirement.	Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009).	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not HVHF wells.	No requirement.	Casing thread compound and its use must conform to the industry standards specified in the permit to drill.	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not HVHF wells.

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Drilling Mud	No requirement.	Compressed air or WBM, no SMB or OBM.	Not listed in Appendix 10, but the RDSGEIS text includes a section that states compressed air or WBM should be used on HVHF wells.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells, not just those described in Appendix 9.	No requirement.	No requirement.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all NYS wells.
Cement Setting Time	Compressive strength standard of 500 psi.	No requirement listed; assume it defaults to Appendix 8 requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have surface casing strings stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi.	No requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have surface casing strings stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells.
NYSDEC Inspector	No requirement.	Required to be onsite for cementing operations.	No requirement.	Best practice is to have a state inspector on site during cementing operations, to verify surface casing cement is correctly installed, before attaching the blowout preventer and drilling deeper into the formation.	No requirement.	No additional requirement.	Best practice is to have a state inspector on site during cementing operations, to verify surface casing cement is correctly installed, before attaching the blowout preventer and drilling deeper into the formation. This requirement should apply to all NYS wells.

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Cement QA/QC - Cement Evaluation Log	NYSDEC reserves the right to require the operator run a cement bond log, but does not require one on every well.	NYSDEC reserves the right to require the operator run a cement bond log, but does not require one on every well.	No requirement listed; assume it defaults to Appendix 8 requirement.	Circulating cement to the surface is one indication of successfully cemented surface casing, but it is not the only QA/QC check that should be conducted. Cement circulation to surface can be achieved even when there are mud or gas channels, or other voids, in the cement column. Circulating cement to the surface also may not identify poor cement to casing wall bonding. These integrity problems, among others, can be further examined using a cement evaluation tool and temperature survey.	No requirement.	No additional requirement.	Circulating cement to the surface is one indication of successfully cemented surface casing, but it is not the only QA/QC check that should be conducted. Cement circulation to surface can be achieved even when there are mud or gas channels, or other voids, in the cement column. Circulating cement to the surface also may not identify poor cement to casing wall bonding. These integrity problems, among others, can be further examined using a cement evaluation tool and temperature survey.
Formation Integrity Test	No requirement.	No requirement.	No requirement.	It is best practice to complete a formation integrity test to verify the integrity of the cement in the surface casing annulus at the surface casing shoe. The test should be conducted after drilling out of the casing shoe, into at least 20 feet, but not more than 50 feet of new formation. The test results should demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the application for the Permit to Drill.	No requirement.	No requirement.	It is best practice to complete a formation integrity test to verify the integrity of the cement in the surface casing annulus at the surface casing shoe. The test should be conducted after drilling out of the casing shoe, into at least 20 feet, but not more than 50 feet of new formation. The test results should demonstrate that the integrity of the casing shoe is sufficient to contain the anticipated wellbore pressures identified in the application for the Permit to Drill. This requirement should apply to all NYS wells.

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BOP Installation	Confirmation that the surface casing is set and cemented into place, such that the BOP can be secured and effective when drilling deeper into the well.	No requirement listed; assume it defaults to Appendix 8 requirement.	No requirement listed; assume it defaults to Appendix 8 requirement.	The Appendix 8 requirement is best practice. Additionally, the surface casing should be pressure tested to ensure it can hold the required working pressure of the BOP.	No requirement.	No requirement.	The Appendix 8 requirement is best practice. Additionally, the surface casing should be pressure tested to ensure it can hold the required working pressure of the BOP. This requirement should apply to all NYS wells.
Record keeping	Not specified.	Not specified.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.	No requirement.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.
Additional Casing or Repair	Not specified.	Not specified.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the Department for environmental and/or public safety reasons, may be required at any time.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.	No requirement.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the department for environmental and/or public safety reasons, may be required at any time.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells, not just HVHF wells.

APPENDIX B

Intermediate Casing Table

Appendix B - Intermediate Casing Table

Intermediate Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Waiver Provision to Exclude Use of Intermediate Casing	Intermediate casing is required on a case-by-case basis.	Intermediate casing is required on a case-by-case basis.	Intermediate casing is required on all wells unless a waiver is granted.	It is best practice to install intermediate casing on a case-by-case basis for most wells; however, it is best practice to install it on all HVHF wells. The waiver provision proposed in the RDSGEIS to exclude intermediate casing on HVHF wells is not technically justified.	No requirement.	Intermediate casing is required on all wells unless a waiver is granted.	It is best practice to install intermediate casing on a case-by-case basis for most wells; however, it is best practice to install it on all HVHF wells. The waiver provision proposed in the RDSGEIS to exclude intermediate casing on HVHF wells is not technically justified.
Setting Depth	No requirement.	No requirement.	The setting depth and design of the casing must consider all applicable drilling, geologic, and well control factors.	Best practice is to set intermediate casing at least 100' below the deepest protected groundwater, to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. Although intermediate casing setting depth is site specific, there should be criteria for determining that depth.	No requirement.	The setting depth and design of the casing must consider all applicable drilling, geologic, and well control factors.	Best practice is to set intermediate casing at least 100' below the deepest protected groundwater, to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. Although intermediate casing setting depth is site specific, there should be criteria for determining that depth. This requirement should apply to all NYS wells.
Protected Water Depth Estimate and Verification	No requirement.	No requirement.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method during drilling, ensuring intermediate casing protects that groundwater.	No requirement.	No requirement.	The freshwater depth should be estimated in the drilling application to aid in well construction design. The actual protected water depth should be verified with a resistivity log or other sampling method during drilling, ensuring intermediate casing protects that groundwater. This requirement should apply to all NYS wells where intermediate casing is set.
Cement Sheath Width	No requirement.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells where intermediate casing is set.
Amount of Cement in Annulus	No requirement.	No requirement.	Intermediate casing must be fully cemented to surface with excess cement.	It is best practice to fully cement intermediate casing if technically feasible to isolate protected water zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. If the casing can not be fully cemented most states require cement to be placed from the casing shoe to a point at least 500-600' above the shoe.	No requirement.	Intermediate casing must be fully cemented to surface with excess cement.	It is best practice to fully cement intermediate casing if technically feasible to isolate protected water zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. If the casing can not be fully cemented most states require cement to be placed from the casing shoe to a point at least 500-600' above the shoe. This requirement should apply to all wells where intermediate casing is set.
Excess Cement Requirement	No requirement.	No requirement.	25% unless a caliper log is run; if a caliper log is run, the excess cement requirement is 10%.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume.	No requirement.	25% unless a caliper log is run; if a caliper log is run, the excess cement requirement is 10%.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where intermediate casing is set.

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Intermediate Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Cement Type	No requirement.	No requirement.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). The cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive.	HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where intermediate casing is installed, not just HVHF wells.	No requirement.	Cement must conform to industry standards, specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content, in accordance with the industry standards, and contain a gas-block additive.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). The cement slurry must be prepared to minimize its free water content, in accordance with the same API specification, and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where intermediate casing is installed, not just HVHF wells.
Cement Mix Water Temperature and pH Monitoring	No requirement.	No requirement.	Cement slurry must be prepared to minimize its free water content, in accordance with industry standards and specifications.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations.	No requirement.	Cement must conform to industry standards, specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content, in accordance with the industry standards.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where intermediate casing is required, not just HVHF wells.
Lost Circulation Control	No requirement.	No requirement.	No requirement.	Lost circulation control is best practice.	No requirement.	No requirement.	Lost circulation control is best practice. This requirement should apply to all NYS wells where intermediate casing is required.
Spacer Fluids	No requirement.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where intermediate casing is used , not just HVHF wells.
Hole conditioning before cementing	No requirement.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.
Cement Installation and Pump Rate	No requirement.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not HVHF wells.

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Intermediate Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Rotating and Reciprocating Casing While Cementing	No requirement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This requirement should apply to all NYS wells.
Centralizers	No requirement.	No requirement.	At least two centralizers (one in the middle and one at the top), and all bow-spring style centralizers, must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002).	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010).	No requirement.	In addition to centralizers otherwise required by the Department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed, and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill.	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where intermediate casing is installed.
Casing quality	No requirement.	No requirement.	New pipe is required and must conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002).	The use of new pipe conforming to API Specification 5CT is best practice.	No requirement.	All casings must be new and conform to industry standards specified in the permit to drill.	The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where intermediate casing is set.
Casing Thread Compound	No requirement.	No requirement.	Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009).	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.	No requirement.	Casing thread compound and its use must conform to industry standards specified in the permit to drill.	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.
Drilling Mud	No requirement.	No requirement.	No requirement.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells during the period when drilling occurs through protected water zones.	No requirement.	No requirement.	The use of compressed air or WBM (with no toxic additives) is best practice when drilling through protected water zones. This should be a requirement for all wells during the period when drilling occurs through protected water zones.
Cement Setting Time	No requirement.	No requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi.	No requirement.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. Additionally, the cement mixture in the zone of critical cement should have a 72-hour compressive strength of at least 1,200 psi. This requirement should apply to all NYS wells, not just HVHF wells.

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NYSDEC Inspector	No requirement.	No requirement.	Required to be onsite for cementing operations.	Best practice is to have a state inspector onsite during cementing operations.	No requirement.	No requirement.	Best practice is to have a state inspector onsite during cementing operations. This requirement should apply to all NYS wells where intermediate casing is installed.
Cement QA/QC - Cement Evaluation Log	No requirement.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the intermediate casing.	The use of a cement evaluation logging tool is best practice.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the intermediate casing.	The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where intermediate casing is set.
Record keeping	Not specified.	Not specified.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.	No requirement.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.
Additional Casing or Repair	No requirement.	No requirement.	No requirement.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the department for environmental and/or public safety reasons, may be required at any time.	No additional requirement.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.

APPENDIX C

Production Casing Table

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Casing Design	No requirement.	No requirement.	Full string of production casing be set across the production zone and be run to surface, and that the production casing be cemented in place.	For all wells, it is best practice for the productive horizon(s) to be determined by coring, electric log, mud-logging,and/or testing to aide in optimizing final production string design and placement. It is best practice to install production casing on a case-by-case basis for most wells; however, it is best practice to install a full string of production casing on HVHF wells to provide a conduit for the HVHF job and provide an extra layer of casing and cement.	The drilling, casing and completion program adopted for any well shall be such as to prevent the migration of oil, gas or other fluids from one pool or stratum to another.	Full string of production casing be set across the production zone and be run to surface, and that the production casing be cemented in place.	For all wells, it is best practice for the productive horizon(s) to be determined by coring, electric log, mud-logging,and/or testing to aide in optimizing final production string design and placement. It is best practice to install production casing on a case-by-case basis for most wells; however, it is best practice to install a full string of production casing on HVHF wells to provide a conduit for the HVHF job and provide an extra layer of casing and cement.
Cement Sheath Width	No requirement.	No requirement.	No requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged.	No requirement.	No additional requirement.	A cement sheath of at least 1-1/4" should be installed. Thin cement sheaths are easily cracked and damaged. This requirement should apply to all NYS wells where production casing is set.
Amount of Cement in Annulus	The production casing cement shall extend at least 500 feet above the casing shoe or tie into the previous casing string, whichever is less. If any oil or gas shows are encountered or known to be present in the area, as determined by the Department at the time of permit application, or subsequently encountered during drilling, the production casing cement shall extend at least 100 feet above any such shows. The Department may allow the use of a weighted fluid in the annulus to prevent gas migration in specific instances when the weight of the cement column could be a problem.	No additional requirement. Appendix 8 requirement would apply.	If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).	Cementing production casing to surface if technically feasible (becomes more difficult with increasing depth), or at least 500' into the intermediate casing string is best practice.	If it is elected to complete a rotary-drilled well and production casing is run, it shall be cemented by a pump and plug or displacement method with sufficient cement to circulate above the top of the completion zone to a height sufficient to prevent any movement of oil or gas or other fluids around the exterior of the production casing.	If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD).	Cementing production casing to surface if technically feasible (becomes more difficult with increasing depth), or at least 500' into the intermediate casing string is best practice. This requirement should apply to all NYS wells where production casing is set.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Excess Cement Requirement	A minimum of 25% excess cement shall be used. When caliper logs are run, a 10% excess will suffice. Additional excesses may be required by the Department in certain areas.	No additional requirement. Appendix 8 requirement would apply.	No additional requirement. Appendix 8 requirement would apply.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume.	No requirement.	No additional requirement.	25% excess cement is standard practice, unless a caliper log is run to assess the hole shape and required cement volume. This requirement should apply to all wells where production casing is set.
Cement Type	No requirement.	No requirement.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive.	HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where production casing is installed, not just HVHF wells.	No requirement.	Cement must conform to industry standards, specified in the permit to drill, and the cement slurry must be prepared to minimize its free water content, in accordance with the industry standards, and contain a gas-block additive.	Cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive. HVHF cement quality requirements (including API specifications and the use of gas-blocking additives) are best practice. However, these practices should apply to all wells where production casing is installed, not just HVHF wells.
Cement Mix Water Temperature and pH Monitoring	The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing tickets and/or the drilling log. WOC time shall be adjusted based on the results of the test.	No additional requirement. Appendix 8 requirement would apply.	No additional requirement. Appendix 8 requirement would apply.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations.	No requirement.	No additional requirement.	Best practice is for the free water separation to average no more than six milliliters per 250 milliliters of tested cement, in accordance with the current API RP 10B. Best practice is to test for pH to evaluate water chemistry and ensure cement is mixed to manufacturer's recommendations. These requirements should apply to all NYS wells where production casing is required, not just HVHF wells.
Lost Circulation Control	No requirement.	No requirement.	No requirement.	Lost circulation control is best practice.	No requirement.	No additional requirement.	Lost circulation control is best practice. This requirement should apply to all NYS wells where production casing is required.
Spacer Fluids	No requirement.	No requirement.	A spacer of adequate volume, makeup and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice.	No requirement.	A spacer of adequate volume, makeup, and consistency must be pumped ahead of the cement.	The use of spacer fluids to separate mud and cement, to avoid mud contamination of the cement, is best practice. This requirement should apply to all NYS wells where production casing is used, not just HVHF wells.
Hole conditioning before cementing	No requirement.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice.	No requirement.	Prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond.	Hole conditioning before cementing is best practice. This requirement should apply to all NYS wells, not just HVHF wells.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Cement Installation and Pump Rate	The pump and plug method shall be used for all production casing cement jobs deeper than 1500 feet. If the pump and plug technique is not used (less than 1500 feet), the operator shall not displace the cement closer than 35 feet above the bottom of the casing. If plugs are used, the plug catcher shall be placed at the top of the lowest (deepest) full joint of casing.	No additional requirement. Appendix 8 requirement would apply.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. The pump and plug installation method is a best practice.	No requirement.	The cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus.	The requirement for cement to be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.
Rotating and Reciprocating Casing While Cementing	No requirement.	No requirement.	No requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This will be come more difficult with a deviated wellbore, but should be attempted if achievable.	No requirement.	No additional requirement.	Rotating and reciprocating casing while cementing is a best practice to improve cement placement. This will become more difficult with a deviated wellbore, but should be attempted if achievable. This requirement should apply to all NYS oil and gas wells, not just HVHF wells.
Centralizers	Centralizers shall be placed at the base and at the top of the production interval if casing is run and extends through that interval, with one additional centralizer every 300 feet of the cemented interval.	No additional requirement. Appendix 8 requirement would apply.	At least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002)	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010).	No requirement.	In addition to centralizers otherwise required by the Department, at least two centralizers, one in the middle and one at the top of the first joint of casing, must be installed, and all bow-spring style centralizers must conform to the industry standards specified in the permit to drill.	The proposed conditions reference an outdated API casing centralizer standard. Best practice is to use at least two centralizers and follow API Recommended Practice for Centralizer Placement, API RP 10D-2 (July 2010). This requirement should apply to all NYS wells where production casing is installed.
Casing quality	The casing shall be of sufficient strength to contain any expected formation or stimulation pressures.	No additional requirement. Appendix 8 requirement would apply.	Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited.	The use of new pipe conforming to API Specification 5CT is best practice.	No requirement.	All casings must be new and conform to industry standards specified in the permit to drill.	The use of new pipe conforming to API Specification 5CT is best practice. This requirement should apply to all NYS wells where production casing is set.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Casing Thread Compound	No requirement.	No requirement.	Casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009).	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.	No requirement.	Casing thread compound and its use must conform to industry standards specified in the permit to drill.	The requirement to use casing thread compound that conforms to API RP 5A3 (November 2009) is a good practice. This requirement should apply to all oil and gas wells, not just HVHF wells.
Cement Setting Time	Following cementing and removal of cementing equipment, the operator shall wait until a compressive strength of 500 psi is achieved before the casing is disturbed in any way.	No additional requirement. Appendix 8 requirement would apply.	After the cement is pumped, the operator must wait on cement (WOC): 1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psi, and 2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test.	Operations shall be suspended until the cement has been permitted to set in accordance with prudent current industry practices.	8 hours Wait on Cement (WOC) and compressive strength standard of 500 psi.	Best practice is to have casing strings stand under pressure until cement reaches a compressive strength of at least 500 psi in the zone of critical cement, before drilling out the cement plug or initiating a test. This requirement should apply to all NYS wells, not just HVHF wells.
NYSDEC Inspector	No requirement.	No requirement.	This office must be notified _______ hours prior to production casing cementing operations.	Best practice is to have a state inspector onsite during cementing operations. This is more typical for surface and intermediate casing, but can be considered for production casing as well.	No requirement.	No additional requirement.	Best practice is to have a state inspector onsite during cementing operations. This is more typical for surface and intermediate casing, but can be considered for production casing as well.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Cement QA/QC - Cement Evaluation Log	No requirement.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the production casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 “Other Testing and Information” under the heading of “Well Logging and Other Testing” of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009).	The use of a cement evaluation logging tool is best practice.	No requirement.	The operator must run a radial cement bond evaluation log or other evaluation tool approved by the Department to verify the cement bond on the production casing.	The use of a cement evaluation logging tool is best practice. This requirement should apply to all wells where production casing is set.
Record keeping	No requirement.	No requirement.	A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.	No requirement.	Records must be kept for five years after the well is P&A'd, and be available for review upon NYSDEC's request.	Best practice is to keep permanent records for each well, even after the well is P&A'd. This information will be needed by NYSDEC and industry during the well's operating life, will be critical for designing the P&A, and may be required if the well leaks post P&A. This requirement should apply to all NYS wells, not just HVHF wells. P&A'd wells do occasionally leak, and well information is may be needed to develop a re-entry, repair, re-P&A plan.

Appendix C - Production Casing Table

Production Casing Requirement	NYS RDSGEIS Appendix 8 Casing and Cementing Practices	NYS RDSGEIS Appendix 9 Existing Fresh Water Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers	NYS RDSGEIS Appendix 10 Proposed Supplementary Permit Conditions for HVHF	Analysis of Proposed NYS RDSGEIS, Permit Conditions and Recommendations	NYCRR Requirement for all NYS Wells, NYCRR Part 554	Additional NYCRR Requirement for HVHF Wells, NYCRR Part 560	Analysis of Proposed NYCRR Requirements and Recommendations
Additional Casing or Repair	No requirement.	No requirement.	Remedial cementing is required if the cement bond is not adequate to effectively isolate hydraulic fracturing operations.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.	No requirement.	The installation of an additional cemented casing string or strings in the well, as deemed necessary by the department for environmental and/or public safety reasons, may be required at any time.	NYSDEC should reserve the right to require industry to install additional cemented casing strings in wells, and repair defective casing or cementing, as deemed necessary for environmental and/or public safety reasons. This requirement should apply to all wells.

Appendix D: List of Acronyms

^{210}Po .... Polonium 210
2D..................... two-dimensional
3D..................... three-dimensional
API .... American Petroleum Institute
API RP .... American Petroleum Institute Recommended Practice
AQ.................... Air Quality
AMD .... Acid mine discharge
ARD .... Acid Rock Drainage
Bcf.................... billion cubic feet
BOP.................. Blow-out preventer
BTEX .... benzene, toluene, ethylbenzene, and xylenes
BUD .... Beneficial Use Determination
C-NLOPB .... Canada-Newfoundland and Labrador Offshore Petroleum Board
CDA .... Concentrated Development Area
CRI................... Cuttings reinjection technology
CRA .... Corrosion-resistant alloys
CRDPF............. Continuously Regenerating Diesel Particulate Filters
DOI .... United States Department of the Interior
DMM .... Division of Materials Management
EAF .... Environmental Assessment Form
EPA .... Environmental Protection Agency
ERP .... Emergency Response Plan
GHG................. Greenhouse Gases
H2S .... Hydrogen Sulfide
HAP .... Hazardous Air Pollutants
HVHF............... High Volume Hydraulic Fracturing
JPAD................ Jonah-Pinedale Anticline Development Area
LDAR............... Leak Detection and Repair
MACT .... Maximum Achievable Control Technology
MFN................. Microseismic Fracture Network
MMscf.............. Million standard cubic feet
MSDS............... Material Safety Data Sheet
MSW................ Municipal solid waste
NAAQS............ National Ambient Air Quality Standards
NACE............... National Association of Corrosion Engineers
NO_X.................. Nitrogen Oxide
NORM .... Naturally Occurring Radioactive Material
NRDC .... Natural Resources Defense Council
NYCRR............ New York Code of Rules and Regulations
NYS .... New York State
NYSDEC .... New York State Department of Environmental Conservation
NYSERDA....... New York State Energy Research and Development Authority
NYSDOH......... New York State Department of Health
OBM .... Oil-Based Mud
OSHA............... Occupational Safety and Health Administration
OSPAR............. Oslo-Paris Convention

P&A ....Plug & Abandonment
PA ....Pennsylvania
PADEP.............Pennsylvania Department of Environmental Protection
PLONOR ....Pose Little Or No Risk
$PM_{2.5}$................Particulate Matter, 2.5 microns or smaller in diameter
POTW..............Publically Owned Treatment Works
ppm ....parts per million
psi.....................pounds per square inch
QC/QA.............Quality Control/Quality Assurance
Ra.....................Radium
RDSGEIS.........Revised Draft Supplemental Generic Environmental Impact Statement
REC..................Reduced Emission Completions
RP.....................Recommended Practice
RCRA...............Resource Conservation and Recovery Act
SBM.................Synthetic-Based Muds
SCR..................Selective Catalytic Reduction
SDWA..............Safe Drinking Water Act
SEQRA ....State Environmental Quality Review Act
SPDES ....State Pollutant Discharge Elimination System
SO_2 ....Sulfur Dioxide
SPCC................Spill Prevention Control and Countermeasures
SPOTS ....Spill Prevention Operations Technology Series
SRB..................Sulfate-reducing bacteria
STEL................Short-term exposure limit
STI ....Steel Tank Institute
SWPPP.............Storm Water Pollution Prevention Plan
TDS..................Total Dissolved Solids
TEG..................Triethylene Glycol
TENORM.........Technologically Enhanced Naturally Occurring Radioactive Material
TVD ....True Vertical Depth
USDW..............Underground Sources of Drinking Water
USEPA.............United States Environmental Protection Agency
USGS ....United States Geological Survey
VOC.................Volatile Organic Compound
WBM ....Water-based muds
WOC................Wait on Concrete

Attachment 2

Tom Myers, Ph. D.

Technical Memorandum

Review and Analysis

Revised Draft

Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program

Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

September 2011

January 5, 2011

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Natural Resources Defense Council

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Contents

INTRODUCTION

This technical memorandum reviews aspects of the *Revised Draft Supplemental Generic Environmental Impact Statement* (RDSGEIS) on the *Oil, Gas and Solution Mining Regulatory Program regarding Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoir*. The New York State Department of Environmental Conservation (NYSDEC) is the lead agency. Throughout this review, I refer to the document as the RDSGEIS. The document was "revised" since its initial publication in 2009. I had prepared a review of the 2009 DSGEIS as Myers (2009).

Appendix A to this technical memorandum is my specific review of Appendix 11 in the RDSGEIS, which has been excerpted from the 2009 DSGEIS without change. Appendix B to this technical memorandum is a paper I wrote which is currently undergoing peer review for a journal; this paper concerns vertical transport of contaminants from the shale to freshwater groundwater.

Since the 2009 DSGEIS, the New York State Energy Research and Development Authority (NYSERDA) contracted with Alpha Geoscience (Alpha) to review the comments I prepared on the 2009 DSGEIS (Myers, 2009). Alpha produced a report titled: *Review of dSGEIS and Identification of Best Technology and Best Practices Recommendations, Tom Myers: December 28, 2009*, prepared by Alpha. The RDSGEIS does not reference, or apparently rely, on this Alpha review in any meaningful way; the bibliography includes a list of 2011 reports by Alpha, but the apparent reference to this review (Alpha 2011) does not include my name. The consultants bibliography includes a subheading with Alpha's report, with "Myers" misspelled, but no apparent use of this reference either. Alpha's reviews prepared for NYSERDA were not available directly on the RDSGEIS web page other than through an obscure link. Appendix C to this technical memorandum is my response to Alpha (2011).

This technical memorandum also reviews the water resources/hydrogeology aspects of the revised regulations, published as *Proposed Express Terms 6 NYCRR Parts 550 through 556 and 560, Subchapter B: Mineral Resources*, referred to throughout as the proposed regulations. This technical memorandum proposes additional regulations throughout the review, and then includes a separate section regarding specific proposed regulations.

The report focuses on three main aspects of the RDSGEIS: (1) hydrogeology, including the hydraulic fracturing (fracking) process, (2) low flow surface water resources, and (3) water-resource-related setbacks. Hydrogeology includes review of the geology, contaminant transport, shale hydrogeology, groundwater quality, and induced seismicity analyses. Low flow surface water resources include an assessment of the analysis required to determine passby flows and the requirements/restrictions on pumping from aquifers. Consideration of the proposed setbacks includes whether the proposed setback is based on facts or analysis. Specific setbacks considered include those proposed to protect aquifers, wells, springs, and other water-related resources.

The RDSGEIS provides data and analysis almost exclusive to the Marcellus shale, although the regulations purport to govern all low-permeability formations, including the Utica shale (which is mentioned in the RDSGEIS). Developing different low-permeability formations would have different effects than would development of the Marcellus shale, which is the focus of the RDSGEIS. Deeper shale, such as the Utica shale, would generate far more cuttings and use more drilling mud, which present different disposal issues. The amount of water used for fracking could be different, as well. Development of shallower shales would increase the regional hydrogeology impacts and increase the potential vertical contaminant transport and the prevalence of improperly plugged abandoned wells. Additionally, the RDSGEIS focused its analysis from the total amount of surface water withdrawals to wastewater disposal on the wells expected in the Marcellus shale. Additional shale development would vastly increase the impacts beyond those revealed in this RDSGEIS

- *The RDSGEIS and proposed regulations should acknowledge that they apply only to the Marcellus shale.*
- *Additional low-permeability gas plays require additional supplemental GEIS analyses as suggested in RDSGEIS 3.2.1*.

The focus on this review is on development of the Marcellus shale, because except for Chapter 4, the RDSGEIS discussion is limited to the Marcellus shale.

SUMMARY OF FINDINGS

The RDSGEIS only poorly describes the hydrogeology of the Marcellus shale area and of the shale in particular. It does not provide a description of what fracking does to the shale or how it affects the regional hydrogeology. There is no description provided of the geologic formations between the shale and the surface beyond the general stratigraphy and stating that it would be nonconductive to upward flow, a point not supported with data or by the literature. The fault mapping is outdated.

Industry should be required to complete geophysical logging, including conductivity, to determine the lower extent of freshwater (Williams 2010). The definition of freshwater should be as protective as federal standards, meaning that surface casing should extend to TDS at 10,000 ppm.

The description of fracking is incomplete and incorrect from a hydrogeologic perspective. The contention that out of formation fracking is rare is incorrect based on industry data which has documented fractures as much as 2000 feet above the top of the shale in other states. Also, the contention that fracking pressure dissipates immediately upon cessation of injection is also incorrect, except right at the well. Model simulations show that pressure in the shale remains elevated for more than three months and that that prevents some of the injected fluid from flowing back to the gas well. The injected fluid displaces substantial amounts of formation fluid from the shale into surrounding formations; existing and new fractures allows that fluid to move much further from the shale than expected due simply to the volume injected.

The RDSGEIS dismisses the concept of contaminant transport from the shale to the near-surface aquifers, but there is overwhelming evidence that it is at least possible. Fracking fluids and methane have been found in water wells from fracking in different areas. Simulations indicate it could occur much more in the future. Fracking displaces large quantities of brine, and fractures provide pathways to the surface; fracking may also widen those existing pathways. Areas of natural artesian pressure would allow advection to move fluids and contaminants vertically upward. Mapping areas of artesian pressure, improved regional fault mapping, and site-specific project by project fault mapping should be employed to avoid areas of enhanced vertical transport potential. Long-term multilevel monitoring is also needed to track the future potential of vertical contaminant movement.

NYSDEC proposes setbacks that are not obviously based on observed data. If the setback from fracking in a protected watershed is 4000 feet, the setback from primary or principal aquifers or from public water supply wells should be no less, unless justified by site-specific analyses. Wells located in a 100-year floodplain have a greater than 1 in 4 chance of being flooded in a 30-year project life, therefore wells should be setback further from streams.

The proposed monitoring plans are paltry and insufficient. Simply monitoring existing water wells only shows when that user is affected, it does not protect the aquifer. Water wells are not designed for monitoring. The industry should establish a dedicated groundwater monitoring system downgradient from every well pad, out to at least the distance that a contaminant would travel in five years. Monitoring should continue for at least five years after the cessation of production.

The required passby flows have improved since 2009, as has the method for determining them. In general requiring the Q60 and Q75 monthly flow avoids diversions at all when flows are in the bottom 40 or 25 percent of their normal monthly flow regime, depending on area and month. Q75 only applies to larger streams (> 50 square mile watershed) during the winter months when flow is generally higher. The RDSGEIS should provide some data to show the estimation methods for ungaged sites is accurate.

HYDROGEOLOGY

This section considers all aspects of the RDSGEIS that concern underground resources, including aspects of geology, shale hydrogeology, contaminant transport, the descriptions of fracking and the potential for fracking-induced seismicity. The toxicity of fracking fluid additives was considered was considered by Dr. Glenn Miller.

General Hydrogeology

The distinction between primary and principal aquifers and other sources (RDSGEIS, p. 2-20) ignores the connections between surface and groundwater. Groundwater from principal aquifers may seep into streams, especially during periods of low flow. Because those aquifers are also used by New Yorkers for water supply, the assertion in the RDSGEIS that "one quarter of New Yorkers … rely on groundwater as a source of potable water" (Id.) understates the number of people who may be affected by groundwater contamination

RDSGEIS Figure 2.1 shows that the north end of the shale parallels a large principal aquifer north of Syracuse. This coincidence deserves explanation at some point in the document.

The RDSGEIS mentions that one quarter of New Yorkers rely on groundwater as a source of potable water (RDSGEIS, p. 2-20). This downplays the connection of groundwater with surface water; many aquifers support stream flow, especially during low flow period, therefore aquifer contamination potentially affects many more people.

Safe yield (RDSGEIS, p. 2-29) is an outdated and flawed concept which should not be repeated in the RDSGEIS. It is flawed because all pumping depletes the aquifer, which contradicts the definition of the phrase (Id.). The preferable concept is sustainable yield which is the amount of water that can be pumped without having significant negative effects on the aquifer and on resources connected to that aquifer; what is significant is a societal question related to the values that depend on the aquifer (Alley et al, 1999).

Presence of Fresh and Salt Water

The federal Safe Drinking Water Act (SDWA) defines an underground source of drinking water (USDW) as "[a]n aquifer or portion of an aquifer that supplies any public water system or that contains a sufficient quantity of ground water to supply a public water system, and currently supplies drinking water for human consumption, or that contains fewer than 10,000 mg/l total dissolved solids and is not an exempted aquifer" (http://water.epa.gov/type/groundwater/uic/glossary.cfm). However, NYSDEC apparently ignores this federal requirement where it specifies that surface casings be extended to 75 feet below the transition from fresh- to saltwater but also specifies 850 feet below ground surface (bgs) as a "practical generalization for the depth to potable water", the point at which near-surface freshwater transitions to saline water, which corresponds to 1000 ppm total dissolved solids (TDS) and 250 mg/l chlorides (RDSGEIS, p. 2-23, 6NYCRR §550(at)). The NYSDEC regulations, by only protecting water to a 1000 ppm cutoff for TDS may not provide protections that for some waters that could apparently meet the definition under the SDWA.

The hydrogeology of southern New York over the Marcellus gas play does suggest that there may be very little water with a TDS higher than the threshold that could actually be developed. Williams (2010) found that freshwater transitions to salt water at about 200 feet bgs in valley areas and about 800 ft bgs in upland areas in three counties in the middle of the Marcellus shale gas play. There was uncertainty around the depth estimates with some freshwater observations at deeper depths. Also the distinction between fresh- and saltwater in his survey of both water and gas wells was based on taste tests rather than any scientific measurement. Williams et al (1998) found similar results in similar geology just across the border in Pennsylvania. Many electric conductivity logs for bedrock water wells in the north Catskill Mountains (Heisig and Knutson 1997) showed that EC would jump from low values representing freshwater to high values representing salt water in a short transition zone or threshold. This suggests that many of the bedrock areas over the Marcellus shale gas play have either high-quality, low-TDS water, or very poor-quality high-TDS water; few wells apparently have water quality near the actual cut-off value. Considering the geology of the area, the zones that have high TDS are also mostly very low hydraulic conductivity zones, so they would not be considered an aquifer because they would not produce sufficient water to support a water supply.

However, the presence of salt water welling up under the alluvial aquifers, which often coincides with fault zones, suggests that salt water does move upward in fractured areas. Water with TDS up to 10,000 ppm may be developable in these higher conductivity fracture zones. In these areas, the NYSDEC regulations may be violating the SDWA requirements to protect USDWs, although the regulations regarding development in primary and principal aquifer may limit drilling in the areas underlain by fractured rock which could have developable high TDS water. Regardless of those aquifer regulations, the threshold for protection should include all areas that qualify as underground sources of water as defined under the Safe Drinking Water Act. These would include waters with TDS up to 10,000 ppm where they exist in an aquifer, and to 1000 ppm or

250 mg/l Cl- in areas underlain by unconductive bedrock. See the separate technical review submitted by Harvey Consulting LLC, for further discussion of the requirements on the SDWA.

- The operator should extend the surface casing to below the 10,000 ppm TDS threshold, unless the operator can show that the formation containing groundwater between 1000 and 10,000 ppm could not produce water in usable quantities. In this case, the operator should extend the surface casing to below the 1000 ppm TDS threshold.

The RDSGEIS does not indicate that the regulations will require the driller to actually locate the transition depth, which would define the depth below which the surface casing would extend a minimum of 75 feet (RDSGEIS, p. 7-50).

- *The regulations should require the operator to complete geophysical logging, including specific conductance logging, prior to casing the well, to determine the actual depth of protected water to which to apply the casing regulations.*

Hydrogeology of the Shale

RDSGEIS Section 4.0 covers Geology, but leaves out most of the important aspects of the Marcellus shale. There is no discussion of hydrogeology of the formations between the targeted shales and the surface, including no discussion of the hydrogeology of the shale itself beyond mention of the permeability. This failure means there is no baseline against which to compare the hydrogeologic changes caused by fracking. There is no hydrogeologic description of the sedimentary layers between the shale and the surface other than very cursory mentions of how it has low permeability. The lack of data on the hydrogeology of formations between the target shale and ground surface is important because NYSDEC relies on geology to “limit or avoid the potential for groundwater contamination” (RDSGEIS, p. 6-2).

Formations that lie between the shale and the surface are generally considered a natural control on fracture propagation and contaminant transport vertically from the shale (RDSGEIS, p. 6-54). RDSGEIS Figure 4-2 does not support the statement that overlying formations will prevent vertical movement of contaminants (RDSGEIS, p. 6-54) because it shows that layers above the Marcellus are primarily sand, limestone, and shale, with no indication of the proportion of each, which controls their conductivity and their propensity to propagate fractures. Most important from the perspective of contaminant transport from the shale to the surface is the prevalence of fractures, both due to faults and otherwise. Faults could be a pathway for vertical contaminant transport (Osborn et al 2011; Myers in review) and could also allow fractures to propagate further from the shale. The RDSGEIS discusses faults only with regard to present day seismicity and the potential for induced seismicity and presents an outdated map (Isachsen and McKendree 1977). A more detailed an integrated analysis of faults and fractures revealed there are many more faults in New York’s Appalachian Basin than previously suspected (Jacobi 2002). The RDSGEIS should include up-to-date information and acknowledge that more faults are probably yet to be found.

There is little information provided in the geology or hydrogeology sections about the make-up of the shale, beyond the amount of organic carbon. The geology chapter does not even mention the presence of pyrite in the Marcellus shale, although there is a brief reference to it for the Utica shale. The sections on "Solids Disposal" mentions pyrite and acid rock drainage of cuttings derived from the Marcellus shale. "As the basal portion of the Marcellus has been reported to contain abundant pyrite (an iron sulfide mineral), there exists the potential that cuttings derived from this interval and placed in reserve pit may oxidize and leach, resulting in an acidic discharge to groundwater, commonly referred to as acid rock drainage (ARD)" (RDSGEIS, p 7-67). ARD will be discussed more below in the Regulations section.

Most industry references state the Marcellus shale is "low-permeability" (RDSGEIS, p. 2), and the proposed regulations apparently rely on this categorization, although not all sources agree with it. Soeder (1988) described Marcellus shale as "surprisingly permeable" and presented data showing the permeability ranges up to 60 microdarcies, as compared to the Huron shale with permeability two orders of magnitude lower. Most reported permeability values are estimated from core samples, but, in a hydrogeologic sense, these estimates do not represent the formation-wide conductivity; point estimates due to scaling effects can be several orders of magnitude less conductive than the formation as a whole due to preferential flow through fractures (Schulze-Makuch et al, 1999), which are prevalent in this area. RDSGEIS Figure 4-2 also does not show the fractures in the overlying formations which prevail throughout New York including in the Marcellus shale zone (Myers in review).

The assertion that the shale requires fracturing "to produce fluids" (Id.) does not prove that the shale above the Marcellus is equally poorly transmissive. Shales above the Marcellus have not apparently trapped gas or fluids for significant time periods, a fact which undercuts the claim they are not transmissive or there is a lack of vertical flow. Fractures that go out-of-formation above the shale connect the shale with the much more transmissive formations above the shale.

The Geology section should also discuss general groundwater flow paths in the formations above the shale; this should include vertical gradients and recharge zones.

- *The RDSGEIS should discuss the hydrogeology of the formations between the targeted shale and ground surface, including data on the hydraulic conductivity of the formations.*

- *The RDSGEIS should also map the groundwater gradients for the formations just above the targeted shale using water level data obtained from geothermal applications and previous deep wells.*
- *The NYSDEC should require the industry to do a seismic survey to locate faults near proposed drilling, within half a mile of the center of the well pad or 1000 feet beyond the projected end of the horizontal wells, whichever is further from the well pad.*
- *The RDSGEIS should include up-to-date fault mapping.*
- *Industry should be required to complete and provide to the NYSDEC geophysical logging of the formations above the targeted shale showing fractures, lithology, and groundwater characteristics.*

Description of Hydraulic Fracturing

RDSGEIS Chapter 5 describes the fracking process, but it does not describe what actually happens to the shale – what does it look like after fracking and what are its properties. It is much more permeable to gas flow, perhaps substantially so, therefore it must also be much more transmissive to water flow. With up to an expected 40,000 horizontal wells over the next 30 years in New York (RDSGEIS, p. 6-6), the properties of the shale, which currently is an aquitard, will change substantially. The RDSGEIS completely fails to address these changes.

Industry designs fracking jobs to keep the fractures in the shale, but data show that the results of the fracking do not always or even often verify the design. The industry rarely monitors or measures the actual extent of fractures (RDSGEIS, p. 5-88), beyond monitoring pressure and injected fluid during fracking. The RDSGEIS references Fisher (2010) as being proof that fractures do not extend into the aquifer zone, but his data actually show that fractures commonly go out of formation (Figure 1). His data show many instances of the top of the fracture zone being more than 1000 feet above the centerline of the shale. As the depth to the centerline of the shale decreases from 8000 to 5000 feet, the vertical fracture growth also appears to decrease from 2000 feet above to 500 feet above the centerline of the shale. The apparent trend to fracture growth above the formation decreasing with decreasing depth may relate to the pressure on the rock or its hardness. The data were not sorted according to formation type and there is no data concerning shale thickness, therefore it is unknown whether fractures extend further in some types of rock or whether out-of-formation fractures are more common with thinner shales.

- *The RDSGEIS should not rely on industry's alleged intent to avoid out-of-formation fracking as a means of preventing the consequences of out-of-formation fracking.*

- *The RDSGEIS and regulations should require geophysical logging and microseismic tests to map how far fractures extend out of formation, and the density of the fractures in different formation. This information should be publically available so that all companies can benefit from experience and so that the public can better understand the process.*

FIGURE 2

Marcellus Shale Mapped Fracture Treatments (TVD)

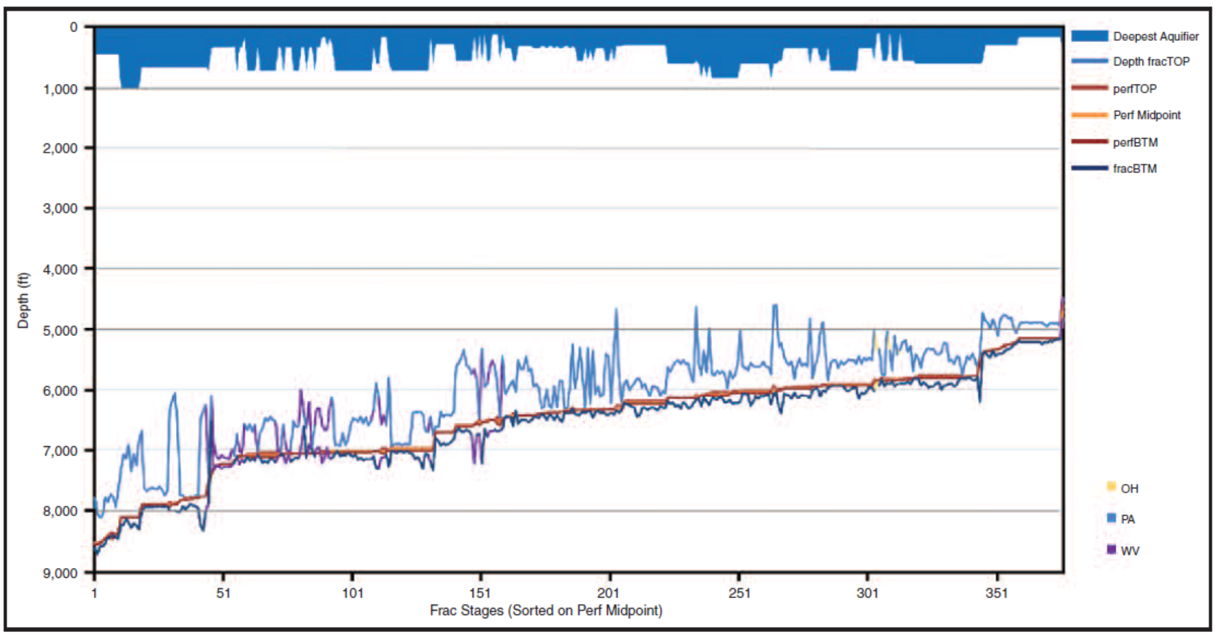

Figure 1: Figure 2 from Fisher (2010) showing the well centerline and a depth to the top of the fracture zone.

It is common practice to compare pressure and flow rate monitoring results from fracking operations to expected values from pre-fracking modeling as a method for evaluating the results of a fracking procedure (RDSGEIS, p. 5-88). Considering that many things affect the pumping flow rate, including pores between the well and the leading extent of the fluid moving away from the well, hydraulically it is difficult to imagine that a significant pressure drop would accompany the leading edge of the fluid reaching surrounding formations. Fracturing into surrounding formations would not bring additional water into the shale, as suggested (Id.), because of the pressures as described elsewhere (Myers in review). The increased porosity in the shale would release substantial brine bound in the shale.

Fracking injects up to 7.2 million gallons of frack fluid into the shale over a well bore up to 4000 ft long – the RDSGEIS suggests these are general upper limits based on fracking in the Marcellus shale in other states. Fractures form or widen as the injection pressure exceeds the normal stress in the shale (RDSGEIS, p. 5-95). The injection would slowly displace any water and gas that exists in the (extremely small) pore spaces near the well; it would push the natural fluid away from the well bore. Because less than 35% of the injected fluid returns to the well as flowback, a significant proportion of the injected fluid remains underground, presumably occupying pores extending out from the well bore. Assuming a job injects 5 million gallons and there is 20% flowback, approximate average values, and 10% effective porosity resulting from the fracking, the fluid could occupy all pore spaces in a 21-ft diameter cylinder centered on the well. Assuming a more realistic resulting effective porosity of 1%, the fluid could fully occupy the pores out to 62 feet in all directions from the well. Fluids that existed there prior to fracking would be pushed further from the wellbore, likely into surrounding formations. Thus, simple consideration of the volume of fracking fluid injected shows that fluid would move far from the well bore and displace formation fluids even further The calculation does not account for pre-existing preferential flow paths or heterogeneities in the direction that fractures develop, so the fluid would likely move further from the well bore in some directions. The fluid would also follow pathways created by the fractures above the shale, thus fluids could end up much further from the well bore than simple considerations would indicate. .

Shale NG development will affect a large proportion of the shale in New York with fracking fluid, as can be shown by comparing expected fracking fluid volumes with shale volume. The RDSGEIS does not indicate the total area of Marcellus shale within New York. However, Figure 2 in Myers (in review) shows the extent of shale within New York to be 18,680 sq miles. Assuming an average thickness of 100 ft, the total volume is 5.2×10^{13} ft^3. If the expected 40,000 wells are all developed in the Marcellus shale, the injected water volume will approximate 2.1×10^{10} ft^3, which at porosity of 0.01 means that fracking fluid would occupy all of the pores in about 4% of the total Marcellus shale volume[1]. This assumes that none of the fluid reaches surrounding formations, which as shown above is unlikely. It is also unlikely that development will be evenly spaced over the shale as supposed in this calculation, therefore the effect in areas of concentrated development could be underestimated.

Fracking efficiency does not improve if the well spacing is significantly less than 300 m, or about 1000 ft (Krissane and Weisset 2011). It is therefore appropriate to assume that fracking changes the shale over the entire spacing unit, or an area of 660 by 4000 ft. The total area affected by 40,000 wells would be about 3800 square miles, which is about 20% of the total shale area in New York. Based on the extent that injected fluid reaches from the well and the frequency of out-of-formation fracturing (Fisher 2010), it is reasonable to conclude that most fracking affects the shale to its edge. Fracking, based on these assumptions, will significantly change the hydrogeology over at least 20 % of a shale aquitard that extends over 18,680 square miles of New York. Because not all of the total area will be developed, it is a good assumption

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[1] This calculation assumes 5,000,000 gallons injected per well and 20% flowback for each of 40,000 wells.

that where development actually occurs, fracking will substantially change the shale hydrogeology.

The statement, that "the volume of fluid used to fracture a well could only fill a small percentage of the void space between the shale and the aquifer" (RDSGEIS, p. 6-53), is also misleading. The total proportion of pores actually filled by injected fluid may be relatively small, but combined with displaced existing brines the injection will affect groundwater over a much larger proportion of the pores. The boundary between salt and freshwater may be displaced or disrupted by advection and dispersion of and by fluids associated with fracking. Additionally the changed properties of the shale over a large area will affect the upward movement of the natural brines. Simple consideration of advection and dispersion shows that the current balance between fresh and salt water could be substantially upset by fracking.

The RDSGEIS also erroneously claims that the pressure applied for injection will dissipate immediately upon cessation of pumping; in the well bore that may be correct, but the fact that pressure exists to push fluid back into the well bore proves that residual pressure remains in the shale and possibly beyond. The statement that "the amount of time that fluids are pumped under pressure into the target formation is orders of magnitude less than the time that would be required for fluids to travel through 1,000 feet of low-permeability rock" (RDSGEIS, p. 5-94, p. 6-53) is technically correct but highly misleading because pressures and conditions for transport from the shale to the near surface will exist long after fracking has finished. Fluids can move away from the well bore at distances from the well bore after the injection ends until the pressure has dissipated; the contrary statement (RDSGEIS, p. 5-94) is wrong in that respect. Myers (in review) describes the modeling of injection and its effect on the pressure distribution in detail. The following is a simpler and more accurate description that should be what appears in the RDSGEIS:

> Hydraulic fracturing involves high pressure injection of fracking fluid into the shale from a horizontal well. This injection fractures the shale and increases the size and connectivity of existing pores. The high pressure creates a pressure gradient from the well to a point in the shale just beyond the expanding volume of injecting fluid where the pressure remains equal to background. If the fluid disperses from the well evenly, the volume will be a cylinder. As injection continues, the radius of the cylinder increases and pressure gradient is from the well to the edge of the cylinder. Offsetting the decreased pressure gradient is an increased effective cross-sectional area for the fluid to cross. The flow away from the well fractures the shale, creating new fractures and increasing the size of the existing fractures. When injection ceases the pressure in the well drops immediately to atmospheric pressure coincident with the well-bottom depth. However, the pressure in the shale begins to drop more slowly, initially equals that caused by injection. Flow away from the well continues as the pressure in the reservoir

created by the HVHF treatment moves fluids towards the well and away from the well both but since there is no more pressure being applied at the well the pressure in the shale near the well begins to drop.

Descriptions in the RDSGEIS (p 5-94) are therefore wrong. Fracking is a transient situation wherein a pressure divide, where the pressure is higher between the well and the end of the fluid, sets up with some fluid movement toward the well and some away from the bore continues. The modeling (Myers in review) shows that this requires about 90 days to effectively dissipate. This counters several statements in the RDSGEIS implying that all fracturing and flow from the well bore ceases at the end of fracking, in about five days.

The claim that the flow direction away from the wellbore would be reversed during flowback (RDSGEIS, p. 6-54) also cannot be correct if only 10 to 30% of the injected fluid actually returns to the well. Some must continue to flow away from, or at least not toward, the well.

NYSDEC makes an unreasonable assumption regarding the flow around the shale after fracking, regarding a discussion of the period between fracking operations if refracking would occur. "It is important to note, however, that between fracturing operations, while the well is producing, flow direction is towards the fracture zone and the wellbore" (RDSGEIS, p. 5-99). Because the goal is to attract gas from the shale, any such low pressure would likely affect just the fracked shale, not formations away from the shale in which fluids would flow according to the background hydraulic gradient. That a small amount of formation water may be produced with time indicates that water from only a small portion of the shale near the well flows toward the well. If the natural gradient in formations above the shale has a vertical component, there will be upward advection of water and contaminants away from the shale.

- *Measurements of the water pressure profile should be made in each well prior to fracking, as it is drilled and before it is cased. This could be a part of the geophysical logging process*.

NYSDEC assumes that it will be rare for a well to be refracked, that is, to repeat the fracking operation years after initially completing it, inappropriately relying on "Marcellus operators'" assurances without reference to a source (RDSGEIS, p. 5-98).

Contaminant Transport from the Shale

The RDSGEIS completely dismisses the concept of vertical contaminant migration from the shale to fresh-water aquifers. Statements suggesting that the only way for the public to be exposed to fracking fluid would be through an accident or spill (RDSGEIS, 5-74) reflect the dismissal of the potential long-term transport from the shale. This section reviews the evidence and potential for contaminant transport from the shale.

Claiming that regulatory officials from 15 states have "testified that groundwater contamination as a result of the hydraulic fracturing process … has not occurred" (RDSGEIS, p. 6-41 & 6-52) is misleading because they have simply never looked for contamination beyond reports from water well owners. There are no monitoring well networks designed to monitor contaminant transport upward from the fracked shale. The upward transport could also take years, decades, or centuries, not just the few days considered in the RDSGEIS. They are wrong to suggest there is no evidence for such transport.

Two reports have documented or suggested the movement of fracking fluid from the target formation to water wells (EPA 1987; Thyne 2008) linked to fracking in wells. Thyne (2008) had found bromide in wells 100s of feet above the fracked zone. The EPA (1987) documented fracking fluid moving into a 416-foot deep water well in West Virginia; the gas well was less than 1000 feet horizontally from the water well, but the report does not indicate the gas-bearing formation. There is also recent evidence of fracking fluid reaching several domestic drinking water wells near Pavillon, WY from a deep source in a sedimentary sandstone and shale formation Diquilio et al 2011). Deep monitoring wells (depth not specified) have detected synthetic organic compounds including glycols, alcohols, and 2-butoxyethanol, BTEX (including benzene at 50 times the MCL), phenols, trimethylbenzenes, and DRO. Dissolved methane was found at near-saturation levels with an isotopic signature similar to production gas. The EPA identified three pathways for fluid movement. One was nearby wellbores. The second was fluid movement from low permeability sandstone into more conductive sandstone nearby. Third was out-of-formation fractures forcing fracking fluid into overlying formations. NYSDEC should consider this example as a cautionary tale of the potential for vertical movement of fracking fluid to near-surface aquifers.

Methane contamination has been observed to occur in many areas near fracking operations. The RDSGEIS acknowledges that gas migration occurs (RDSGEIS, p. 6-42), but suggests it is limited to well construction problems. This assumption ignores the studies which link the source to much deeper formations (Osborn et al 2011, Thyne 2008). Myers (in review) and Osborn et al (2011) indicate that gas transport could indicate pathways which could also be longer-term fluid pathways; if there is a pathway for gas, there is also a pathway for water.

The RDSGEIS dismisses diffusion of chemicals from the shale to the surface because this would dilute their concentrations; this is correct, but diffusion is only a minor process in the movement of chemicals to the surface and is the wrong process to analyze for consideration of whether vertical transport could occur. Contaminants move by advection, dispersion, and diffusion, with the later being a minor component. Advection would be the most likely transport process (Myers in review). Upward movement of chemicals could occur by advection wherever there is an upward vertical component to the hydraulic gradient; fractures and faults would enhance that flow. Myers (in review) simulated transport through the bulk media as requiring from 100s to 1000s of years, depending on hydraulic properties and gradient; fractures substantially decreased that simulated time.

The RDSGEIS relies on an analysis by ICF (2009), included in the RDSGEIS as Appendix 11, for its dismissal of potential vertical contaminant transport. Dismissing the potential for such transport based on the gradient occurring just for the time of fracking simply illustrates a lack of understanding of the process and associated groundwater and contaminant flow. ICF (2009) had been part of the 2009 version of the DSGEIS. Appendix A of this technical memorandum reviews ICF (2009) again in detail and Appendix B presents a copy of a journal article (Myers in review), which analyzes in detail the potential for transport from the shale to the surface.

The RDSGEIS should reconsider some of its assumptions and implement several regulatory changes, as specified here:

- *ICF (2009) should be removed in its entirety and substituted with an analysis that at least acknowledges the potential risk for long-term contaminant transport from the shale to the surface. All citations to and conclusions based on ICF (2009) should also be removed from the RDSGEIS.*
- *The RDSGEIS should include the foregoing recommendations concerning hydrogeology, and regulations should be promulgated specifically requiring the delineation of properties of the geologic formations above the shale, the locations of fractures, and mapping of the hydraulic gradients near the proposed drillsites.*
- *The RDSGEIS and regulations should require driller to implement a long-term monitoring plan with wells established to monitor for long-term upward contaminant transport, as described below in the section concerning groundwater monitoring.*

Other Pathways for Groundwater Contamination

Section 2.4.5 incorrectly claims that "[i]mproperly constructed water wells can allow for easy transport of contaminants to the well…" (RDSGEIS, p. 2-22). Transport "to the well" depends on flowpaths and gradients near the well which would only marginally be affected by well construction. Improper water well construction does allow transport of contaminants along the casing which could allow contaminants to move among aquifers, once the contaminants reach the well. Improperly constructed wells can allow contaminants from aquifer layers which were not intended to be screened to transport to the producing layers.

Flowback and produced water are important potential contaminants, primarily in the potential for blowouts or spills just after fracking and in the potential for leaks from the well bore. Estimates are that from 9 to 35% of the injected fracking fluid, expected to vary from 2.4 to 7.8 million gallons per well, would return as flowback (RDSGEIS, p. 5-99). This is a total flowback of 216,000 to 2.7 million gallons per well (Id.). Estimates also indicate that up 60 percent of the flowback would return within the first four days after fracking ceases (RDSGEIS, p. 5-100). The upper estimate based on these ranges is that 60 percent of 2.7 million gallons, or 1.62 million gallons of flowback will occur within four days of the cessation of fracking. Modeling in Myers (in review) confirms both the relative proportion of injected fluid that becomes flowback and the rapid rate.

Flowback is a mixture of returning fracking fluid and formation fluid, but the limited chemistry data presented in the RDSGEIS suffers from being a single sample per well (RDSGEIS, p. 5-105). The RDSGEIS states that some of the data was provided by the Marcellus Shale Coalition, an industry group, but without reference or actually providing the data; it is not possible for the reader to assess or draw independent conclusions that might differ from the statements in the RDSGEIS. The available data does not apparently allow an assessment of the proportion of shale to injected water. For example, samples with very high salt content probably consist more of shale brine than fracking fluid. RDSGEIS Table 5.10 demonstrates, by its illustration of poor water quality, that the water must be contained. The minimum, median, and maximum for TDS, at 1530, 63,800, and 337,000 mg/l, respectively, suggests the proportions vary widely but that more than half of them are saltier than ocean water. The range in chemicals such as benzene, at 15.7, 479.5, and 1950 ug/l, shows that some flowback could be extremely toxic; the NY MCL for benzene is 5 ug/l, thus most of the samples above detect exceed the standard for this contaminant. Because of the toxic chemistry of flowback water, much more data is necessary, as specified here:

- *The RDSGEIS should present temporal flowback data from specific wells, in tabular or graphical form.*
- *The RDSGEIS should present an appendix with raw data provided by the Marcellus Shale Coalition or link to the data on the internet*.
- *Table 5.10 could be made more understandable by including the detect and MCL levels.*

The RDSGEIS promises that flowback would be contained in “water-tight tanks” for onsite handling (Id.), but the document does not discuss the sizing of the tanks. The proposed regulations address flowback and requirements for capturing it at many points (6 NYCRR §560), but also fails to specify a size. For example, the operator must include “ the number and total capacity of receiving tanks for flowback water” (6 NYCRR § 560.3(a)(12)), and must have secondary containment, “as deemed appropriate by the department”…”sufficient to contain 110 percent of the total capacity of the single largest container or tank within a common containment area” (6 NYCRR § 560.6(x)(26)(i)). Because there are no specifications for the size of the “single largest container”, the required secondary containment sizing is not useful.

- *The RDSGEIS and proposed regulations must specify the necessary total capacity for tanks to contain flowback. The required capacity must reasonably exceed the expected flowback as discussed above. It must be able to capture within four days, 60 percent of the 35 percent of the maximum amount of fluid to be injected for fracking.*

RDSGEIS Chapter 5 lists many chemicals that could be used in fracking fluid, but does not list any properties of these chemicals which could affect their flow through soils or through groundwater. The RDSGEIS does not provide data regarding whether and how much they will be attenuated. However, the RDSGEIS inappropriately relies on attenuation (p. 6-53) to mitigate against the potential for long-distance transport.

- *The RDSGEIS should either provide data concerning the transport properties of the various chemicals or not rely on attenuation as a means of mitigating the transport which could results from spills and leaks.*

Groundwater Quality Monitoring

The previous sections of this report have highlighted the poor water quality of fluids associated with fracking operations – the fracking fluid itself and the produced shale-bed water – and the various pathways for aquifers to be contaminated. Small quantities of either of these fluids can significantly pollute groundwater and surface water. The RDSGEIS provides some setbacks in an attempt to protect various receptors – wells, aquifers, or streams – and the adequacy of these is discussed below. With the potential for spills and leaks from multiple sources associated with these operations, the requirements for groundwater quality monitoring in the RDSGEIS and the regulations is paltry and insufficient, as described here.

The proposed monitoring consists only of testing existing private water wells within 1000 ft of the drill site, or to 2000 ft if none are located within 1000 ft (RDSGEIS, p. 1-10, 7-44). While this is necessary for the protection of the well owner, it is insufficient for the long-term protection of the aquifer. Domestic wells have not been designed to function as water quality monitoring wells which causes many problems in sampling and interpreting the data. Thyne explains clearly why domestic wells are poor monitoring wells:

> First, the number of domestic well sample points is far exceeded by the potential point sources (gas wells). Domestic wells are much less than ideal for sampling purposes. Domestic wells are not placed to determine sources of contamination in groundwater. They are not evenly spaced around gas wells or within close enough proximity to determine the presence of chemicals associated with methane that degrade rapidly. Domestic wells are generally screened over large intervals making vertical spatial resolution for samples difficult nor are the wells are not constructed to facilitate measurement of water table elevation or downhole sampling. This forces sampling to occur at the surface after pumping raising the possibility of sampling artifacts. In addition, since domestic wells are the sole source of drinking water for individual properties, it is difficult to arrange access to take samples due to privacy issues, and the County may bear potential liability for damage during sampling and interruption of water supply. (Thyne 2008, p 10-11)

A monitoring well system should be designed so that a contaminant plume will neither pass horizontally between the monitoring wells nor above or below the screened interval. The best way to be certain of intercepting a contaminant passing a point in an aquifer is to span the entire aquifer with well screen. A long screen may increase the chances of detecting the presence of a potential contaminant which may indicate the site being monitored has developed a leak, but will dilute the concentration by mixing contaminated water with cleaner water. A sample extracted from such a well will be a conglomerate of the chemistry of the entire screen thickness; if the screen spans multiple lithologies, the water within the well bore will not be representative of any lithology (Shosky, 1987). It can only be effective only for substances which do NOT naturally exist in the region of the aquifer. Monitoring with long screens is good only for presence/absence determinations.

Concentrations vary throughout an aquifer, both vertically and horizontally. The concentration determined from any well will represent an average over the entire screen length. Therefore, to monitor trends in concentration, screens should span representative vertical sections

The spatial layout of the monitoring well system should be based on the conceptual flow and transport model for flow from the gas well through the aquifer, which includes flow pathways and possible contaminant dispersion. Monitoring wells should be placed as close to the expected flow path as possible, where the concentration will be highest. However, because of uncertainty in the prediction of the flow path, monitoring wells should also be spaced laterally away from the expected flow path. These lateral wells should detect lower concentrations than the one in the predicted flow path. If the lateral wells actually have higher concentration, the predicted flow path may be incorrect and monitoring wells should be added further from the predicted flow path to improve the understanding of the flow and movement of the contaminant plume.

Monitoring wells or piezometers should be placed close to the potential source for early detection, but also at a distance from the source to increase the chances that they will intercept the contaminant and to assess the rate of contaminant movement. If many wells detect the contaminant, the concentration variation would indicate the degree of dispersion. Denser well networks will have a better chance of detecting the contaminant and providing accurate description of it dispersal.

Considering the above fundamentals of a monitoring system, the following recommendations, in addition to sampling the existing private wells, should be added to the RDSGEIS and partly replace proposed regulations in 6 NYCCR §560.5(d)

- *The operator should prepare a conceptual flow path model for groundwater and contaminant transport from the drill pad to and through nearby aquifers.*
- *As part of the conceptual model, the operator should estimate the distance that a contaminant would travel from the well pad in various time periods, including one month, six months, one year, and five years.*
- *Dedicated groundwater monitoring wells should be reasonably located along and perpendicular to the projected flow path out to the five-year travel distance. At a minimum, there should be a transect of monitoring wells/piezometers at the one-month travel distance from the well and halfway between the well and important receptors, meaning wells or discharge points such as springs or streams.*
- *Monitor wells should span the surface aquifer and piezometers should have multiport sampling capabilities for twenty foot intervals at the top of the saturated zone and every 100 feet to the bottom of the freshwater zone. This will help establish vertical concentration and hydraulic gradients.*
- *The monitoring system should be established to establish baseline data including seasonal variability for at least one year prior to drilling and fracking.*

Monitoring transport from the deep shale is more difficult because a substantial flux of contaminants could be released from most anywhere in the fractured shale as a result of oil and gas development. Time intervals for transport could be more than 100 years, but fractures could decrease the time frame to as short a time as a few years. Fracture zones therefore could be monitored, but if they are known the industry should avoid fracking near them, both to avoid vertical transport and induced seismicity. It is therefore reasonable to require a dedicated monitoring well in the middle of each well pad wherever there is an upward flow gradient.

- *Industry should establish a multiport piezometer system from the shale to the bottom of the freshwater zone in the center of all well pads.*

- *The industry should provide the funding to maintain the piezometers system for at least 100 years beyond the end of gas production, to account for the long potential travel times.*

WATER RESOURCES

This section concerns primarily the controls on making water withdrawals for fracking. The section focuses on surface water diversions but also considers diversions from aquifers.

The RDSGEIS notes correctly that without proper controls, the withdrawals of water from streams and aquifers to use in fracking could have significant ecologic and hydrologic impacts (RDSGEIS, p. 6-2). The "natural flow paradigm" is a good description of the interdependencies of the stream ecology with all of the hydrologic regimes (RDSGEIS, p. 6-4). The description of the depletion to an aquifer and the interconnection of aquifers with surface water (RDSGEIS, p. 6-5) is also good. Treating the withdrawals as consumptively lost to the system (RDSGEIS, p. 6-9) is appropriate because in essence, with recycling of flowback, the water will not return to the system. These are acknowledgements which should lead to good regulation of withdrawals, if properly considered in the rulemaking.

The discussion and comparison of the withdrawals for fracking with statewide water uses (Withdrawals for High-Volume Hydraulic Fracturing, RDSGEIS, p 6-9 thru 6-13) are scientifically unsupported and irrelevant;. The potential impacts of withdrawals are a matter of scale and depend on their size, the size of the stream, and antecedent moisture conditions.

Much of the regulation of withdrawals from streams focuses on passby flows. The RDSGEIS defines a passby flow as "a prescribed quantity of flow that must be allowed to pass an intake when withdrawal is occurring" (RDSGEIS, p 2-30) which also specifies a low flow condition "during which no water can be withdrawn" (Id.). Specific definitions will be discussed below, but in reality the lower specified values can allow significant damage to occur to streams, especially smaller ones. If the required passby flow is small compared to the average, meaning it has a long return interval, it will only rarely restrict water withdrawals. If flows on the river can be reduced to a low passby flow, then diversions can reduce the flow to low, long return interval rates much more frequently; this is tantamount to imposing low-frequency, high-damaging, drought on the streams much more frequently.

The Delaware River Basin Commission (DRBC) does not have a specific passby flow requirement and usually uses the 7Q10 flow, the seven-day low flow with a ten-year return interval, for water resources evaluation (RDSGEIS, p. 7-13). The RDSGEIS indicates this is not protective (Id.) and as described in the previous paragraph, it would allow the 10-year low flow to manifest much more frequently. The Susquehanna River Basin Commission (SRBC) regulations are more complicated, but generally use the 7Q10 or from 15 to 25 percent of the average daily flow (RDSGEIS, p 7-15, 16). Neither is protective and the NYSDEC proposes to use the natural flow regime method (NFRM) method for all regions (RDSGEIS, p 7-16).

The RDSGEIS expresses the intent to use the NFRM only in permit conditions, however, as the document acknowledges that guidance has not yet been completed (RDSGEIS, p. 7-3). As authority, the RDSGEIS cites 6 NYCRR § 703.2, which states that "[n]o alteration that will impair the waters for their best usages" will be allowed. "For the purpose of this revised draft SGEIS only, the Department proposes to employ the NFRM via permit conditions as a protection measure pending completion of guidance." (Id.). NYSDEC also indicates that the requirement could be "imposed via permit condition and/or regulation" (RDSGEIS, p. 7-22).

- *NYSDEC must include the requirement for using the NFRM in the regulations if it is to be consistently enforceable; the proposed regulations do not currently require use of the NFRM to establish the requisite passby flow in a stream.*

The NFRM attempts to protect the distinctive flow patterns for each stream, including the "variable magnitude, duration, timing, and rate of change of flow rates and water levels" (RDSGEIS, p 7-18).   The RDSGEIS proposes to use the "Q75 and/or Q60 monthly exceedence values for establishing passby flows" (Id.). An Qx exceedence value is the flow rate which is exceeded x percent of the time. Another way of considering the Q75 and Q60 exceedance values is that the passby flow would be greater than the flow which the stream exceeds 25 or 40 percent of the time. This is much higher than a 7Q10 flow. However, in a small stream, diversions could change a flow regime from wet (higher than average) to significantly below average.

NYSDEC appears to intend that if the watershed exceeds 50 square miles, the passby flow will be Q75 for the winter/spring months of October through June and Q60 for the summer months of July through September, whereas for smaller watersheds (Area<50 sq miles), the Q60 value applies all year (RDSGEIS, p 7-19). NYSDEC at least recognizes that small streams need more protection and that low flows can be more critical during the summer when temperatures are higher. This means that at least 40 percent of the time, withdrawals will not be allowed. For another short time period (up to the time for which the actual streamflow and the required passby flow is less than the preferred withdrawal rate), withdrawals will be limited to prevent the streamflow from being reduced to below the passby flow.

The RDSGEIS does not discuss how the recommended passby flows were chosen, in terms of habitat protected. There is an implication that Q60 and/or Q75 mean the same amount of habitat would be protected; this may simply be incorrect because streams are not created equal. The NYSDEC should apply a second filter and actually require a determination of the habitat at Q60 and limit the change in habitat. This is one advantage of the Susquehanna River Basin Commission method (RDSGEIS, p 7-15, -16).

The flow estimation method assumes a linear relation between baseflow and drainage area (RDSGEIS, p 7-19). The assumption is that streamflow increases consistently in a downstream direction in proportion to the contributing drainage area. Because it is essential to the method, the RDSGEIS should present data to justify their assumptions. Analyzing streams with two or more gages, the Qx flow at one would be calculated according to the area proportionality relationship with the other gage; the RDSGEIS should present this type of verification to prove the method is suitable.

On streams without gages, the RDSGEIS indicates that NYSDEC will use factors developed from regression equations based on their location in New York (RDSGEIS, Fig 7.1, Table 7.2). The table provides coefficients in cfs/sq mi for the passby flow for the different geographic zone by month. Presumably, they are based on basin areas as discussed above, with different requirements for greater than and less than 50 sq miles. The RDSGEIS should compare values determined with Table 7.2 with the actual value determined for gaged streams to verify the table. Statements such as "[t]he passby flow requirement … would fully mitigate any significant adverse impact from water withdrawals" (RDSGEIS, p 7-22) are unsubstantiated and unjustified.

The passby flow requirements effectively ignore the potential cumulative impacts, irrespective of the following sentence: "The application of the NFRM to all water withdrawals to support the subject hydraulic fracturing operations would comprehensively address cumulative impacts on stream flows because it will ensure a specified minimum passby flow, regardless of the number of water withdrawals taking place at one time" (RDSGEIS, p. 7-25). The RDSGEIS continues by indicating that "significant adverse cumulative impacts would be addressed by the NFRM … because each operator … would be required, via permit condition and/or regulation, to estimate or report the maximum withdrawal rate and measure the actual passby flow for any period of withdrawal" (RDSGEIS, p. 7-25, -26). The RDSGEIS analysis of the prevention of cumulative flow impacts appears limited to these statements. Clearly, several concurrent withdrawals along a stream reach could cumulatively decrease the flow at the more downstream sites to less than the passby flow, if the timing of withdrawals is not controlled and if there are not adequate measurements ongoing at the site which compare the actual flow to the required passby flow. Short of establishing a gaging station with flow/stage relationship, it is difficult to measure flows frequently enough to monitor short-term flow changes, therefore it is unlikely that an operator would be able to react sufficiently to preserve the passby flow.

The following are recommendations for improving the passby flow requirement to be used by NYSDEC

- *The program must be codified into regulations.*
- *The methods for estimating passby flows at ungaged sites must be verified as to their accuracy.*
- *NYSDEC should coordinate operators so their withdrawals do not cumulatively cause flows to drop below the required passby flows at any point along the stream.*
- *The operator should establish a temporary flow/stage relationship with at least a staff gage that should be monitored.*
- *Passby flows should be maintained with consideration to the measurement error inherent in the technique. The operator should assume that the measurement method is overestimating flow and therefore maintain a flow greater than the passby flow by as much as the error estimate.*

NYSDEC recognizes that groundwater pumping could deplete streams and also recognizes that pumping effects on the aquifers must be limited (RDSGEIS, pp 6-5, -6). Regarding groundwater pumping, the "Department proposes to impose requirements regarding passby flows as stated in this document" (RDSGEIS, p 7-25). The RDSGEIS does not discuss how the potential impacts to a stream will be estimated or how passby flows will be maintained, especially considering the lag time between groundwater pumping and the time for effects to manifest in the streams.

- *NYSDEC should prohibit groundwater pumping in tributary watersheds when analysis indicates that the time for a pumping effect to reach the stream is less than 30 days.*
- *NYSDEC should require a suitable groundwater analysis to estimate the effect on groundwater discharge to streams.*

The RDSGEIS indicates that industry has begun recycling more of its wastewater (RDSGEIS, p. 1-2). Recycling flowback water is good for reducing the amount of water to be disposed of, but it will not significantly decrease the water volume needed for fracking because the amount recovered as flowback is just 10 to 30 percent of the amount originally injected. Tracking the flowback to be recycled should be part of the new "Drilling and Production Waste Tracking" process (RDSGEIS, p. 1-13).

PROJECT MITIGATION MEASURES

The primary mitigation schemes proposed in the RDSGEIS are setbacks, which the RDSGEIS treats as additional precautionary measures (RDSGEIS, p. 1-11). This section considers whether the setbacks are sufficient or arbitrary. A list in section 1.8 introduces additional precautionary measures; they are repeated in section 3.2.4. The following lists the proposed mitigation setbacks from the RDSGEIS and provides brief comment:

> "Well pads for high-volume hydraulic fracturing would be prohibited in the NYC and Syracuse watersheds, and within a 4,000-foot buffer around those watersheds."

The primary pathway if wells are prohibited within 4000 feet of the watershed boundary would be underground, since topography would cause contaminants to flow away from the watershed boundary, assuming this coincides with a topographic divide. In general, 4000 feet is probably sufficient, but a site specific consideration of the geology should be included to ascertain that the groundwater divide would not place the well within the watershed and that geologic formations are not dipping in the direction of the watershed.

- *This setback is not specified in the regulations, but should be.*
- *The operator should be required to analyze the local geology to determine whether the groundwater divide would allow transport into the prohibited watershed.*

> "Well pads for high-volume hydraulic fracturing would be prohibited within 500 feet of primary aquifers (6 NYCCR §560.4(a)(2),(subject to reconsideration 2 years after issuance of the first permit for high-volume hydraulic fracturing)"

The implication of only a 500 –ft setback is that there is no groundwater connection, but if groundwater in the bedrock connects with the aquifer, there is a potential for a rapid transport of contaminants from a spill through fractures to the aquifer. Contamination will easily spread through the highly conductive aquifer (RDSGEIS, p. 6-37). The risk to the aquifer would be the same as to the prohibited watersheds, so there is no reason the distance should be different. If the ground surface slopes from the well to the primary aquifer, there is a significant risk of a spill reaching the aquifer through surface channels.

- *The prohibition in* 6 NYCCR §560.4(a)(2) *should be increased to 4000 feet, unless a site specific analysis demonstrates there are no fractures connecting the bedrock with the aquifer and there are no obvious surface water pathways.*
- *Additionally, the RDSGEIS should publish the area the Marcellus shale zone overlapped by primary aquifers and the area that would be included as buffer; this would help the public to understand how much land the prohibition affects.*

> "Well pads for high-volume hydraulic fracturing would be prohibited within 2,000 feet of public water supply wells, river or stream intakes and reservoirs (6 NYCCR

§560.4(a)(4)) (subject to reconsideration 3 years after issuance of the first permit for high-volume hydraulic fracturing)"

Essentially, there is no reason for this offset to be less than the offset from a primary aquifer. Considering a public water supply well, the operator should be required to perform a capture zone analysis for the well, and if the well could draw contaminants from a spill to the well, the gas well should not be permitted in that location.

- *The setback for public water supply wells should also be 4000 feet.*
- *Additionally, the operator should identify the capture zone for flow to the well and identify the five year transport distance contour.*

"The Department would not issue permits for proposed high-volume hydraulic fracturing at any well pad in 100-year floodplains". (6 NYCCR §560.4(a)(4))

For wells that might operate for 30 years, there is a 26% chance[2] of a 100-year flood occurring during the period the well would be operated.

- *Wells should be prohibited within at least the 500 year return interval floodplain, because the damages from significant flooding could be very substantial.*

"The Department would not issue permits for proposed high-volume hydraulic fracturing at any proposed well pad within 500 feet of a private water well or domestic use spring, *unless waived by the owner*." (6 NYCCR §560.4(a)(4)), emphasis added.)

NYSDEC should not allow the owner to waive this requirement because health and safety are at risk. More than just the "owner" may use the source, and the owner could sell to someone who does not understand the situation.

- *6 NYCCR §560.4(a)(1) should be changed to remove the waiver from the water well owner unless the owner is required to disclose the waiver to a future buyer in perpetuity.*

In general, some of the points discussed above mention that NYSDEC will revisit the need for the setback in the future. These reconsiderations are not part of the regulations. If so, the NYSDEC should specify in detail the performance standards that must be met in order for the setback requirement to be relaxed, and should acknowledge that a supplemental EIS would be completed to consider those changes.

[2] The probability that a event with a p probability will occur during n observations (years) may be determined with a binomial distribution.

The RDSGEIS also specified the following factors which would require site-specific SEQRA analysis.

1) Any proposed high-volume hydraulic fracturing where the top of the target fracture zone is shallower than 2,000 feet along any part of the proposed length of the wellbore.
2) Any proposed high-volume hydraulic fracturing where the top of the target fracture zone at any point along any part of the proposed length of the wellbore is less than 1,000 feet below the base of a known fresh water supply.
These requirements should be considered together – if the top of the shale is less than 2000 feet bgs or 1000 feet below the bottom of the aquifer, a site-specific SEQRA review will be required. The depths seem arbitrary, and must be based on a perceived potential for vertical transport from the shale to the receptor.

3) Any proposed well pad within 500 feet of a principal aquifer:
The only difference between a primary and principal aquifer is the number of people potentially using the aquifer. Principal aquifers are thought to be productive enough to be an important source and contamination with fracking fluid or flowback could render them unusable without substantial remediation. Wells near principal aquifers should be subject to the same setback as well near a primary aquifer.

4) Any proposed well pad within 150 feet of a perennial or intermittent stream, storm drain, lake or pond:
Again, rather than allowing development subject toa site-specific study, development within 150 feet of these streams should be prohibited. It is difficult to imagine how study will prevent a spill which is, by its nature, unexpected.

5) A proposed surface water withdrawal that is found not to be consistent with the Department's preferred passby flow methodology as described in Chapter 7;
Revised Draft SGEIS 2011, Page 3-16
6) Any proposed water withdrawal from a pond or lake;
7) Any proposed ground water withdrawal within 500 feet of a private well;
8) Any proposed ground water withdrawal within 500 feet of a wetland that pump test data shows would have an influence on the wetland:
Requirements 5 through 8 are acceptable limits for requiring site-specific study.

9) Any proposed well location determined by NYCDEP to be within 1,000 feet of its subsurface water supply infrastructure

This applies to areas outside the NYC watershed that contain NYC infrastructure (RDSGEIS, p 6-1). It is unclear whether there is any infrastructure that would actually be affected by fracking outside of the watershed. Fracking should not be allowed within 1000 feet of any NYC water supply infrastructure to prevent damage.

Acid Rock Drainage

The RDSGEIS refers in several locations to an acid rock drainage (ARD) mitigation plan which would be required for the on-site burial of Marcellus Shale cuttings (RDSGEIS, p 7-67). In general, our recommendation is that on-site burial not be allowed (see the report by Harvey Consulting, LLC). NYSDEC does not describe an adequate mitigation plan to prevent the leaching of ARD into groundwater. It does not specify testing which is essential to know how much neutralizing rock must be supplied.

For each well, prior to disposal of the cuttings, an adequate set of samples should be collected from the cuttings to test for acid generation. Adequate sampling would be representatively spaced along the horizontal well bore; initially, many samples would be needed to determine the variability among samples; samples every 100 feet would be desirable until sufficient data is collected from New York shales to characterize the variability along the horizontal well bore.

At least three types of testing should be completed:

- Acid base accounting – Modified Sobek procedure
- Net acid/alkaline production
- Meteoric water mobility testing – ASTM E-2242-02

These tests should provide adequate information to determine the amount of neutralizing rock which should be added to the cuttings to prevent ARD from leaching through the waste. Ideally, if the rock is potentially acid generating (PAG), kinetic tests should be completed to better assess the PAG potential, but this may not be possible in a timely fashion. The regulations should reflect these testing requirements. Final disposal must include adequate encapsulation to assure neutralization in perpetuity. It must also include adequate monitoring to assure that ARD does not leach into the underlying groundwater. A mitigation plan must be in place to remediate any disposal sites that do leak ARD.

COMMENTS ON SPECIFIC PROPOSED REGULATIONS

The proposed regulations increase the overlap lengths for cement plugs in abandoned O&G wells from 15 to 50 feet at several locations (6 NYCRR§ 555.5(a)). This increase in plug length is an improvement but not sufficient or well planned in all locations. Rather than filling "with cement from total depth to at least 50 feet above the top of the shallowest formation from which the production of oil or gas has ever been obtained in the vicinity" (6 NYCRR§ 555.5(a)(1)), the regulation requiring cementing to 50 feet above the top of the shallowest formation in which gas has been observed; not all gas pockets have actually produced gas but could cause methane contamination if they are not already sealed off by casing. The regulations should specify that the cement plug "below the deepest potable fresh water level" should overlap the transition than be just below it because even a short section of uncased well bore open to the salt water could mix into the well and to above the fresh water line (6 NYCRR§ 555.5(a)(3)).

The definition of "public water supply" (6NYCRR§ 560.2(19)) appears to include only groundwater by referring to "a…well system which provides piped water". However, the definition of "reservoir" (6NYCRR§ 560.2(20)) includes "waterbody designated for use as a dedicated public water supply". The regulations must clear up this inconsistency by making clear that a "public water supply" includes ground- and surface water.

Operators must include in their applications various items (6NYCRR§ 560.3). The following address some of these requirements by number (the setback requirements were addressed above in the section concerning setbacks).

(2): The estimated maximum depth and elevation of bottom of potential freshwater: The operator should also be required to complete geophysical logging including conductivity measurements to verify the depth, unless it had been based on "previous drilling on the well pad".

(3): The "proposed volume of water to be used in hydraulic fracturing": The operator should also be required to discuss and specify how the estimated volume was determined.

(5), (6): The two parts specify that the application will provide the distance to various features but only if they are within a given specific distance. With current geographic information systems technology, there is no difficulty in obtaining these distances. The application should provide the distance to the water supply features in (5) and the aquifer and stream features in (6) if they are within two miles.

Mapping requirements for the application are specified in 6 NYCCR § 560.3(b). The topographic map requirements (6 NYCCR § 560.3(b)(2) require essentially a site map within 2640 feet of the proposed surface location (RDSGEIS, p. 3-9). This should be increased to 1 mile from the site, so that the map would be two by two miles centered on the proposed well pad. The map should include locations of all aquifers, water wells, stream channels, and other water features. The map should also include surface geology including faults. If fractures dominate the surface bedrock, contaminants can move quickly to wells. Contaminant pathways for transport from the pad should be identified on the map. Contaminants would not move far upgradient, so the NYSDEC should focus downgradient. The following recommendations should be included in regulations regarding the requirements of well drillers to take steps to protect nearby wells.

- *The operator should complete site specific geology/hydrogeology studies to map the potential flow paths for contaminants released from the well pad or the well bore.*
- *All wells within a five-year transport zone should be located and included in sampling plans discussed below. Additionally, dedicated monitoring wells should be established within this zone, also as described below.*

The regulations require the operator to record and report the depths and flow rates where "freshwater, brine, oil and/or gas were encountered or circulation was lost during drilling operations" (6 NYCCR 560.6(c)(22)). The operator should identify these areas with specific conductivity logging. The regulations do not specify any limits or actions that the operator should take if certain flow or losses were recorded; they do not specify what the department will do with this information.

The required treatment plan "must include a profile showing anticipated pressures and volumes of fluid for pumping the first stage" (6 NYCCR 560.6(c)(22)). The operator also "must make and maintain a complete record of it hydraulic fracturing operation including the flowback phase" (6 NYCCR 560.6(c)(26)viii). The operator should compare the "anticipated pressures and volumes" with the actual values.

The operator must suspend operations immediately "if any anomalous pressure and/or flow conditions is indicated or occurring which is a significant deviation from either the treatment plan" (6 NYCCR 560.6(c)(26)vii). This is good, but the regulations do not define anomalous or what a significant deviation from the treatment plan would be, or what the follow-up action would be to assess and remedy damages.

Also, the required record of the fracking operation, 6 NYCCR 560.6(c)(26)viii, includes rates, volumes, and pressures of all injected and flowback fluids to the well. The department only requires a synopsis be provided to the department. There is no description what a synopsis should include. Instead, the department should require the full record be provided to the department, and this record should be made publically available online.

The regulations allow a well owner to waive setback requirements (6NYCRR§ 560.4(a)(1)). This should not be allowed unless there is also a requirement to inform potential purchasers of the well in the future of the waiver.

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APPENDIX A

Review of Appendix 11, Excerpt from ICF Report, Task 1, 2009

Analysis of Subsurface Mobility of Fracturing Fluids

Agreement No. 9679

Reviewed by

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December 7, 2009

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Introduction

The New York State Energy and Development Authority (NYSERDA) contracted with ICF International to prepare a review of the hydraulic fracturing process as it will likely be applied to the Marcellus Shale in New York; this review was published as a supporting document for the 2009 RDSGEIS prepared by the New York State Department of Environmental Conservation. For the 2011 RDSGEIS, Appendix 11 presents excerpts from that report regarding the subsurface mobility of fracturing fluids. This is a review of Appendix 11, revised from a review completed by this author of the ICF International report contained in the 2009 RDSGEIS.

In summary, ICF completed an analysis of the potential for contamination to flow from the shale to freshwater aquifers, but misrepresented the actual situation in many ways. The basic problem was they conceptualized the flow potential incorrectly. They considered the gradient incorrectly and assumed that if the transport did not occur within the time period of fracturing, it would not occur. They assumed that the fluids leaving the shale would completely disperse, and be diluted, by occupying and being retained in every pore between the shale and the aquifers. They did not consider preexisting fractures. They ignored any potential pre-existing vertical gradient which would drive contaminants leaving the shale to the aquifers. Although they presented a geochemical analysis which could explain why some attenuation could occur, they provided no site specific or fluid specific data to indicate that it would occur.

Exposure Pathways

ICF analyzes the potential for fracturing fluid to flow from the shale to the freshwater aquifers anywhere from 1000 to 5000 feet above. The first problem is that the potential contaminants are both fracturing fluid and connate (formation) water existing in the shale before fracturing, which could contain extremely high concentrations of TDS, benzene, or radioactive materials. Therefore, ICF should have considered the potential for flow of both fracturing fluid and connate water. Ambient water could both be pushed from the shale by the injection of fracturing fluid and just by the opening of the pore spaces which would increase the permeability and allow more of a natural connection.

ICF calculates the gradient between the fracture zone and the bottom of the freshwater zone, which they set at 1000 feet bgs to be conservative in because much of the groundwater below this level in southern New York is not an underground source of drinking water either because it is too salty or the formation is not sufficiently productive to be considered an aquifer. However, their calculation applied only during the period of injection. Myers (in review) demonstrated through modeling that the fracking pressure would dissipate over a period of months, not immediately after fracking ended, because of the fluid that has been pushed away from the well. The effective gradient is from the well to just beyond the migrating fluid where pressures would not yet have been affected by the current fracking.

ICF also ignores the potential for a natural upward gradient, which could be due to natural artesian pressure. Myers (in review) also discusses the potential for this in detail.

ICF properly calculated the pressure that would occur in the shale during fracturing based on the effective stress in the formation and the amount of pressure required to overcome the in-situ horizontal stress (ICF, pages 25-26); accepting the assumptions in the following quote, equation 12, and equations 7 through 11 used to derive it, is an accurate description of the head applied to the shale during fracturing.

> Since the horizontal stress is typically in the range of 0.5 to 1.0 times the vertical stress, the fracturing pressure will equal the depth to the fracture zone times, say, 0.75 times the density of the geologic materials (estimated at 150 pcf average), times the depth. To allow for some loss of pressure from the wellbore to the fracture tip, the calculations assume a fracturing pressure 10% higher than the horizontal stress… (ICF, pages 25-26)

ICF uses that equation with the gradient equation 6 to estimate the gradient between the shale and freshwater aquifer, "during hydraulic fracturing", for a variety of depths of the aquifer and the shale. The numbers are correct, for an aquifer depth of 1000 feet and shale depth of 2000 feet, they show the gradient to be about 3.6, but the concept applied in the derivation is wrong as described above. During hydraulic fracturing, variously estimated through the RDSGEIS documents as occurring for up to 5 days, there is no hydraulic connection between the shale and the bottom of the freshwater aquifer and it is therefore inappropriate to consider the gradient across that thickness. The correct conceptualization is described in the following paragraph.

Upon applying a pressure in the shale, as occurs during the injection for fracturing, a very high pressure head is developed at the well and nearby shale. This pressure causes the gradient that drives the fluid away from the well into the shale, where it causes the shale to fracture. Fluid may continue to flow into surrounding formations. During the process, the pressure begins to increase away from the well which establishes a steep gradient near the well. Away from the well at any given time during injection, the pressure is less than at the well. The pressure drop from the well to any point in the shale away from the well is a function of the friction incurred by the fluid flowing away from the well. At some distance from the well, the pressure is only at background. The distance at which the pressure is only background is the point at which the injection fluid has not yet reached. Beyond the point to which the injection fluid flows, there is NO hydraulic connection. For this reason, ICF's calculation for gradient between the injection pressure in the shale and the bottom of the freshwater aquifer is hydrogeologically incorrect. ICF is effectively analyzing a steady state situation that would occur if the injection pressure continued until the pressure stabilized between the shale and the freshwater aquifer.

ICF acknowledges the reality that transient or non-steady conditions will prevail and that the actual pressure gradient will be higher closer to the shale. "In an actual fracturing situation, non-steady state conditions will prevail during the limited time of application of the fracturing pressures, and the gradients will be higher than the average closer to the fracture zone and lower than the average closer to the aquifer." (ICF, pages 26-27)

However, they do not carry the analysis any further and seem to argue that immediately after injection ceases, all upward gradient will cease: "It is important to note that these gradients only apply while fracturing pressures are being applied. Once fracturing pressures are removed, the total head in the reservoir will fall to near its original value, which may be higher or lower than the total head in the aquifer" (ICF, page 27). The implication from this statement is that ending injection will cause the pressure in the reservoir to drop back to background, immediately. This is not possible, any more than it is possible for the drawdown in a pumping well in an aquifer to return to pre-pumping conditions immediately upon cessation of pumping.

For example, consider that during a five-day injection period, the pressure propagated outward from the well as described in Myers (in review). When injection ends, the pressure within the well may almost immediately return to background, but the pressure in the surrounding formation will still be very high. This is the pressure which will drive the flowback to the well, as described throughout the RDSGEIS. The initial flowback is fluid right next to the well – the fluid that had just been injected. The pressure field created in the formation away from the well is the pressure that causes a gradient to push the fluid back into the well.

As long as there is flowback, there is a gradient toward the well, and residual pressure in the shale or surrounding formations. With distance from the well, the pressure increases (as required for there to be a gradient back to the well). At any given time, there will be a point of maximum pressure beyond which the pressure becomes lower; in other words, a cross-section through the formation away from the well showing the pressure head would show the pressure rising from the well to the peak and falling from the peak to the point the pressure reaches background. (This is similar to the concept in hydrogeology that during pumping, the maximum drawdown caused by a well is at the well; when the well ceases to pump, the water level will initially rise quickly, but the drawdown away from the well will continue to expand for a period of time.)

ICF considers that local drawdown caused by production from the well will further prevent flow away from the well: “During production, the pressure in the shale would decrease as gas is extracted, further reducing any potential for upward flow” (ICF, page 27). This is probably correct, but the process described in the preceding paragraph likely causes some of the fluid to have moved beyond this propagating drawdown. The fact that only 35% of the injected fluid returns as flowback (RDSGEIS, Gaudlip et al, 2008) would seem to confirm that much of the injected fluid gets beyond the point where the reversing gradient would pull the fluid back to the well.

ICF also relies on there being no connection between the shale and surrounding formations, as indicated by the high TDS content of water in the shale. This may reflect the pre-fractured conditions, but the fracturing process could open a connection between formations. As noted in the main body of this review, out-of-zone fracking is not uncommon, therefore it is reasonable to assume that connections between the shale and surrounding formations do occasionally occur.

The analysis provided by ICF in section 1.2.4.3, Seepage Velocity, is irrelevant because it considers the velocity between the shale and the freshwater aquifer, using a gradient established in the previous section that only applies for as long as the injection. Their calculation of 10 ft/day (ICF, page 28) relies on that average gradient. They seem to acknowledge the fallacy of their assumptions by stating: “The actual gradients and seepage velocities will be influenced by non-steady state conditions and by variations in the hydraulic conductivities of the various strata” (ICF, page 28, emphasis added). ICF carries the error into section 1.2.4.4, Required Travel Time, by calculating how long it would take for flow at the seepage velocity calculated in the previous section to reach the freshwater aquifers.

ICF's fourth argument is that even if all of the injected fluid moves vertically out of the shale towards the freshwater aquifer, it would have to disperse among all of the pores between the shale and the aquifer – a truly nonsensical idea. The calculation requires that 4,000,000 gallons of fluid would be evenly dispersed throughout a 40-acre well spacing. In other words, they assume that about 4,000,000 gallons of injected fluid would evenly disperse through all of the void, assuming porosity of 0.1, over a 1000-foot thickness 40 acres in area, or about 1.3 billion gallons of void space, would cause a dilution factor of 300 (ICF, pages 30-31). This is wrong for the following reasons.

- An injected fluid would move as a slug along the gradient. In this case, with a natural upward gradient, any fluid that escapes the well bore (does not flowback) would disperse upward. It would not diffuse through every pore space between the shale and aquifer. Advective forces would move it upward as a slug with dispersion spreading it out both vertically and horizontally. It will dilute, but far less than postulated by ICF's analysis.
- The vertical flow would follow preferential flow paths rather than advecting upwards uniformly across 40 acres. The image painted by ICF is that the fluid would flow upward to the aquifer with the leading edge moving at exactly the same rate over the entire area. Even if there are no fractures, faults, or improperly plugged wells, simple finger flow, caused by heterogeneities in the material properties, would cause an uneven distribution of the contaminant.

ICF also rejects the concept of fractures, faults, or unplugged wells by claiming it is "extremely unlikely that a flow path such as a network of open fractures, an open fault, or an undetected and unplugged wellbore could exist that directly connects the hydraulically fractured zone to an aquifer" (ICF, page 31). They provide no data or references to assess the probability that such a network is "extremely unlikely" or to justify their conclusion. More importantly, for fractures to facilitate a connection between the shale and the aquifers, it is not necessary for the fracture to exist over the entire thickness. As ICF (page 5) mentions, the Marcellus Shale has substantial natural fractures, and therefore it is possible that the surrounding formations, sandstone or shale, also have fractures. It is not necessary for the flow to follow a fracture all the way to the aquifers, but it could enhance the velocity of movement. Fractures could also further disperse the flow vertically, as discussed in Myers (in review).

ICF also mentions geochemistry as a reason that transport of contaminants from the shale to the aquifers will not occur. While it is possible for attenuation to occur as contaminants move through a formation, without site specific and chemical specific data, they should not make such an argument.

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APPENDIX B

Prepublication Copy

Myers, T., in review. POTENTIAL CONTAMINANT PATHWAYS FROM HYDRAULICALLY FRACTURED SHALE TO AQUIFERS

POTENTIAL CONTAMINANT PATHWAYS FROM HYDRAULICALLY FRACTURED SHALE TO AQUIFERS

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ABSTRACT

Hydraulic fracturing (fracking) of deep shale beds to develop natural gas has caused concern regarding the potential for various forms of water pollution. Two potential pathways – diffuse transport through bulk media and preferential flow through fractures – could allow the transport of contaminants from the fractured shale to aquifers. There is substantial geologic evidence that natural vertical flow drives contaminants, mostly brine, to near the surface from deep evaporite sources. Interpretative numerical modeling shows that diffuse transport could require up to tens of thousands of years to move contaminants to the surface, but also that fracking the shale could reduce that transport time to tens or hundreds of years. Conductive faults or fracture zones, as found throughout the Marcellus shale region, could reduce the travel time further. Injection of up to 15,000,000 liters of fluid into the shale generates high pressure at the well which decreases with distance from the well and with time after injection as the fluid advects through the shale. The advection displaces native fluids, mostly brine, and fractures the bulk media and widens existing fractures. Simulated pressure returns to pre-injection levels in about 90 days. The overall system requires from three to six years to reach a new equilibrium reflecting the significant changes caused by fracking the shale. The rapid expansion of hydraulic fracturing requires that monitoring systems be employed to track the movement of contaminants and that gas wells have a reasonable offset from faults.

Introduction

The use of natural gas (NG) in the United States has been increasing, with 53 percent of new electricity generating capacity between 2007 and 2030 projected to be with NG-fired plants (EIA 2009). Unconventional sources account for a significant proportion of the new NG available to the plants. A specific unconventional source has been deep shale-bed NG, including the Marcellus shale primarily in New York, Pennsylvania, Ohio, and West Virginia (Soeder 2010), which has seen over 4000 wells developed between 2009 and 2010 in Pennsylvania (Figure 1).Unconventional shale-bed NG differs from conventional sources in that the permeability is so low that gas does not naturally flow in timeframes suitable for development. Hydraulic fracturing (fracking, the industry term for the operation (Kramer 2011)) loosens the formation to release the gas and provide pathways for it to move to a well.

Fracking injects 13 to 19 million liters of fluid consisting of water and additives, including benzene at concentrations up to 560 ppm (Jehn 2010), at pressures up to 69,000 kPa (PADEP 2011) into low permeability shale to force open and connect the fractures. This is often done using horizontal drilling through the middle of the shale. Horizontal wells may be more than a kilometer (km) long. The amount of injected fluid that returns to the ground surface after fracking ranges from 9 to 34 percent of the injected fluid (Alleman 2011; NYSDEC 2009), although some would be formation water.

Many agency violation reports and legal citations (ODNR 2008; PADEP 2009) and peer-reviewed articles (DiGuilio et al. 2011; Osborn et al. 2011; Breen et al. 2007; White and Mathes 2006) have found more gas in water wells near areas being developed for unconventional NG, documenting the source can be difficult. One reason for the difficulty is the different sources – thermogenic for gas formed by compression and heat at depth in shale and bacteriogenic for gas formed by bacteria breaking down organic material (Schoell 1980). The source can be distinguished based on both C and H isotopes and the ratio of methane to higher chain gases (Osborn and McIntosh 2010; Breen et al 2007). Thermogenic gas can reach aquifers only by leaking from the well bore or by seeping vertically from the source. In either case, the gas must flow through potentially very thick sequences of sedimentary rock to reach the aquifers. Many studies which have found thermogenic gas in water wells found there to be more gas near fracture zones (DiGuilio et al. 2011; Osborn et al. 2011; Thyne 2008; Breen et al. 2007), suggesting that fractures are pathways for gas to move from shale or other deep formations to aquifers.

A pathway for gas would also be a pathway for fluids and contaminants to advect from the fractured shale to the surface, although the time for transport would likely be longer. Two reports (DiGuilio et al. 2011; EPA, 1987) have documented the presence of fracking fluid in aquifers and another found elevated chloride (Thyne 2008), linked to fracking, in wells, although the exact source and pathways had not been determined.

There is sufficient documented gas movement and circumstantial evidence regarding fluids movement to suggest that there is a potential for fracking fluid or shale-bed formation fluid to reach aquifers. With the vastly increasing development of unconventional NG sources, the risk to aquifers could seemingly be increasing. However, there is almost no data concerning the movement of contaminants along pathways from depth, either from wellbores or from deep formations, to aquifers. The only way in the short term to explore the risk is with conceptual analyses.

To consider the potential transport from depth to aquifers, I have considered first the potential pathways for contaminant transport through bedrock between deep shale and surface aquifers, and the necessary conditions for such transport to occur. Second, I have estimated contaminant travel times through the potential pathways, with a bound on these estimates based on formation hydrologic parameters, using interpretative MODFLOW-2000 computations. The modeling does not, and cannot, account for all of the complexities of the geology, which could either increase or decrease the travel times compared to those considered herein. The intent of this study is to characterize the risk factors, so the modeling is used, similar to that by Hsieh (2011), to consider the possibilities.

The Marcellus shale area of northern Pennsylvania and southern New York is the study area (Figure 1), although the concepts should apply anywhere there is a deep unconventional NG source separated from the surface by sedimentary rock.

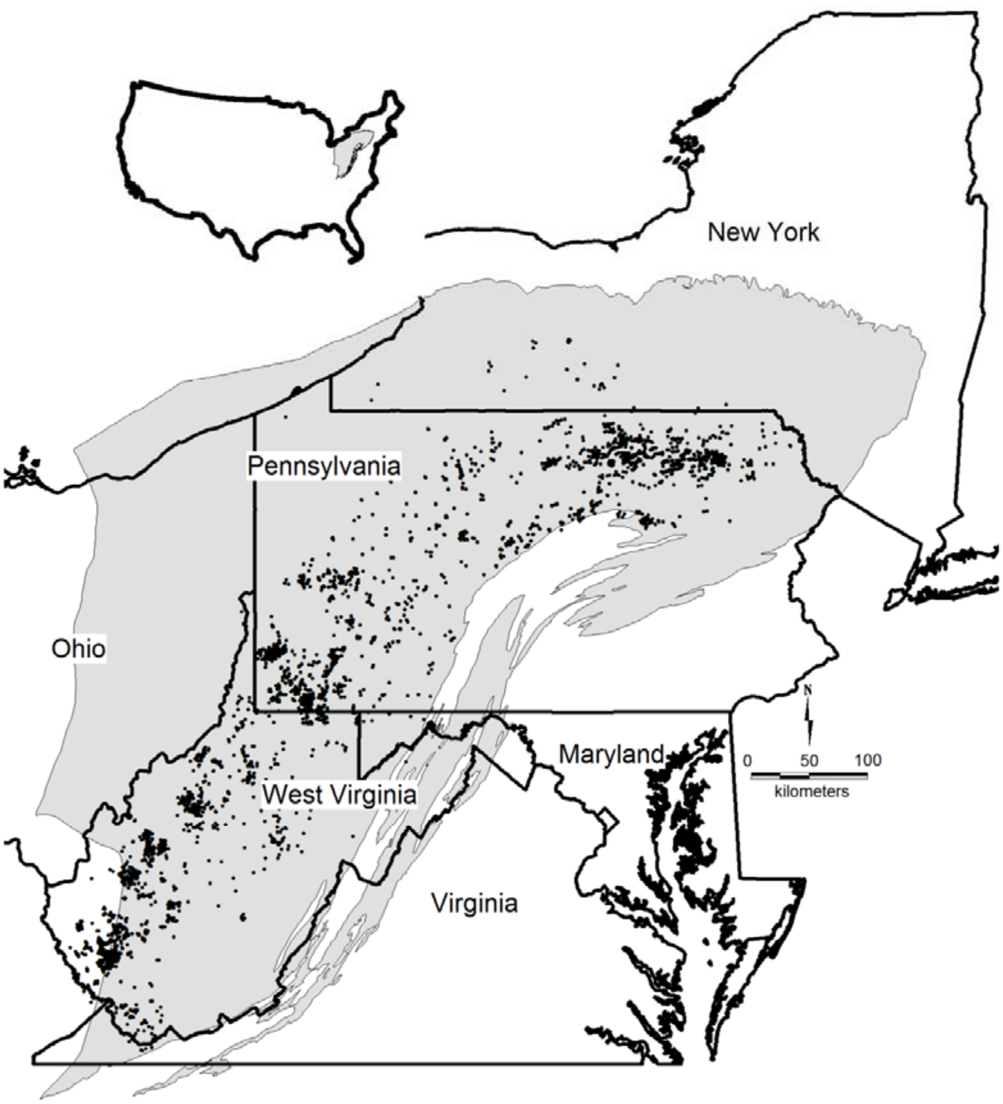

Figure 2: Location of Marcellus shale in northeastern United States. Location of Marcellus wells (dots) drilled July 2009 to June 2010 and total Marcellus shale wells in New York and West Virginia. There are 4064 wells shown in Pennsylvania, 48 wells in New York, and 1421 wells in West Virginia. Faulting in the area may be found in PBTGS (2001), Isachsen and McKendree (1977), and WVGES (2011, 2010a and 2010b).

Method of Analysis

I consider several potential scenarios of transport from shale, 1500 m below ground surface to the surface, beginning with pre-development steady state conditions to establish a baseline and then scenarios considering transport after fracking has potentially caused contaminants to reach the overlying formations. To develop the conceptual models and MODFLOW-2000 simulations, it is necessary first to consider the hydrogeology of the shale and the details of hydraulic fracturing, including details of how fracking changes the shale hydrogeologic properties.

Hydrogeology of Marcellus Shale

Shale is a mudstone, a sedimentary rock consisting primarily of clay- and silt-sized particles, which tend to break in one direction (Nichols 2009). It forms through the deposition of fine particles in a low energy environment, such as a lake- or seabed. The Marcellus shale formed in very deep offshore conditions during Devonian time (Harper 1999) where only the finest particles had remained suspended. Because sufficient organic matter settled with the clay and silt, anaerobic decomposition caused the formation of methane. The depth to the Marcellus shale varies to as much as 3000 m in parts of Pennsylvania, and averages about 1500 m in southern New York. Between the shale and the ground surface are layers of sedimentary rock, including sandstone, siltstone, and shale (NYSDEC 2011).

Marcellus shale has very low natural intrinsic permeability, on the order of 10^{-16} Darcies (Kwon et al. 2004a and 2004b; Neuzil 1994 and 1986), which makes it an extremely efficient seal, or capstone, for keeping natural gas in underlying sandstone. At a gradient equal to 1 with an intrinsic permeability equal to 100×10^{-9} darcies, water would flow only 0.000025 m in a year.

Schulze-Makuch et al. (1999) described Devonian Shale of the Appalachian Basin, of which the Marcellus is a major part, as containing “coaly organic material and appear either gray or black” and being “composed mainly of tiny quartz grains < 0.005 mm diameter with sheets of thin clay flakes”. Median particle size is 0.0069±0.00141 mm with a grain size distribution of <2% sand, 73% silt, and 25% clay. Primary pores are typically 5 x 10^{-5} mm in diameter, matrix porosity is typically 1% to 4.5% and fracture porosity is typically 0.078 to 0.09% (Schulze-Makuch et al. 1999 and references therein).

The Marcellus shale is fractured by faulting and contains synclines and anticlines which cause tension cracks (Engelder et al. 2009; Nickelsen 1986). It is sufficiently fractured in some places to support water wells just six to ten km from where it is being developed for NG at 2000 m below ground surface (bgs) in eastern Lycoming County, Pennsylvania (Lloyd and Carswell 1981) (Figure 2).

Porous flow in unfractured shale is negligible due to the low bulk media permeability, but at larger scales the fractures control and may allow significant flow. Conductivity scale dependency (Schulze-Makuch et al.1999) may be described as follows:

$$K = Cv^m$$

K is hydraulic conductivity (m/s), C is the intercept of a log-log plot of observed K to scale (the K at a sample volume of 1 m^3), V is sample volume (m^3), and m is a scaling exponent determined with log-log regression; for Devonian shale, C equals -14.3 and m equals 1.08 (Schulze-Makuch et al. 1999). Most of their samples were small because the deep shale is not easily tested at a field-scale and no groundwater models have calibrated for flow through the Marcellus shale, therefore field scale K estimates are uncertain. Considering a 1 km square area with 30 m thickness, the Kh would equal 5.96x10^{-7} m/s (0.0515 m/d). This effective K is low and the shale would be an aquitard, but a leaky one.

Contaminant Pathways from Shale to the Surface

Three studies (Osborn et al. 2011; Thyne 2008; Breen et al. 2007) have found gas in near-surface water wells and suggested that the most likely cause was vertical transport of gas from depth, possibly linked to the presence of faults through which the gas could flow. Osborn et al. (2011) found systematic circumstantial evidence for higher methane concentrations in wells within 1 km of Marcellus shale gas wells that had been fracked. Gas moves through fractures depending their width (Etiope and Martinelli 2001) and is a primary concern for many projects, including carbon sequestration (Annunziatellis et al. 2008) and natural gas storage projects (Breen et al. 2007).

Pathways for gas suggest pathways for fluids and contaminants, if there is a gradient. Vertical hydraulic gradients of a up to a few percent, or about 30 m over 1500 m, exist throughout the Marcellus shale region as may be seen in various geothermal developments in New York (TAL 1981). Brine more than a thousand meters above their evaporite source (Dresel and Rose 2010) is evidence of upward movement of contaminants from depth to the surface. The Marcellus shale, with salinity as high as 350,000 mg/l (Soeder 2010; NYDEC 2009), may be a primary brine source. Relatively uniform brine concentrations over large areas (Williams et al. 1998) suggest widespread diffuse transport, which would occur if there is a sufficient concentration gradient. The transition from briny to freshwater suggests a long-term equilibrium between the upward movement of brine and downward movement of freshwater.

Faults, which occur throughout the Marcellus shale region (Gold 1999), could provide pathways (Caine et al. 1996; Konikow 2011) for more concentrated advective and dispersive transport. Brine concentrating in faults or anticline zones reflects potential preferential pathways (Wunsch 2011; Dresel and Rose 2010; Williams 2010; Williams et al. 1998).

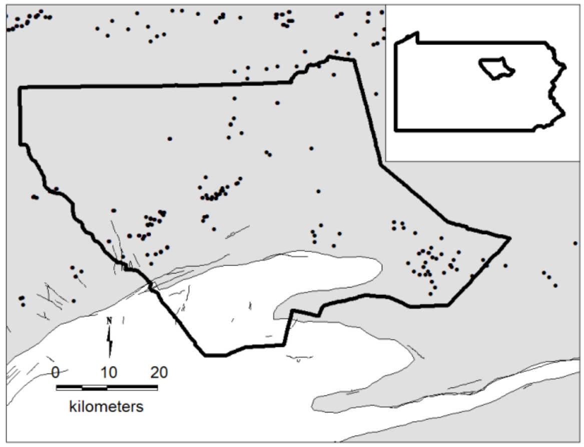

Figure 3: Marcellus shale wells and the Marcellus outcrop in Lycoming County, Pennsylvania. The grey shading is the area of Marcellus shale, which outcrops along its boundary along an area about 1 km wide (Lloyd and Carswell 1981). Faults from PBTGS (2001).

Effect of Hydraulic Fracturing on Shale

Fracking increases the permeability of the targeted shale to make extraction of natural gas economically efficient (Engelder et al. 2009; Arthur et al. 2008). Fracking creates fracture pathways with up to 9.2 million square meters of surface area in the shale accessible to a horizontal well (King 2010; King et al. 2008) and connects natural fractures (Engelder et al. 2009; King et al. 2008). No post-fracking studies that documented hydrologic properties such as conductivity were found while researching this article (there is a lack of information about pre- and post-fracking properties (Schweitzer and Bilgesu 2009)), but it is reasonable to assume the K increases significantly because of the newly created and widened fractures.

Fully developed shale typically has wells spaced at about 300-m intervals (Krissane and Weissert 2011; Soeder 2010). Up to eight wells may be drilled from a single well pad (NYDEC 2009; Arthur et al. 2008), although not in a perfect spoke pattern. Reducing by half the effective spacing did not enhance overall productivity (Krissane and Weissert 2011) which indicates that 300–m spacing creates sufficient overlap among fractured zones to assure adequate gas drainage. The properties controlling groundwater flow would therefore be affected over a large area, not just at a single horizontal well or set of wells emanating from a single well pad.

Fracking is not intended to affect surrounding formations, but shale properties vary over short ranges (King 2010; Boyer et al. 2006) and out of formation fracking is not uncommon. Fluids could reach surrounding formations just because of the volume injected into the shale, which must displace natural fluid, such as the existing brine in the shale. For example, if 15 million liters is injected into shale over a 1000 m long horizontal well, the fluid could occupy all of the pore spaces within 7 to 16 m from the well for effective porosity ranging from 0.1 to 0.02. Even with 20% of the fluid returning to the well, a significant amount of existing pore space would be occupied by the injected fluid, displacing the existing brine and gas.

Analysis of Potential Transport along Pathways

Fracking could cause contaminant to reach overlying formations either by fracking out of formation, connecting fractures in the shale to overlying bedrock, or by simple displacement of fluids from the shale into the overburden. Advective transport will manifest if there is a significant vertical component to the regional hydraulic gradient. Advective transport can be considered with the simple particle velocity determined with Darcy velocity and effective porosity.

Numerical modeling provides flexibility to consider potential conceptual flow scenarios, but should be considered interpretative (Hill and Tiedeman, 2007). Numerical simulation presented herein was completed with the MODFLOW-2000 code (Harbaugh et al. 2000). The simulation considers the rate of vertical transport of contaminants to near the surface for the different conceptual models, based on an expected, simplified, realistic range of hydrogeologic aquifer parameters.

MODFLOW-2000 is a versatile numerical modeling code, but it is not perfect for all of the factors required for this simulation. The native water at depth near the shale is brine, much saltier than seawater, therefore the injected fluid would be lighter so buoyancy factors may speed the upward flux beyond the simple consideration of hydraulic gradient. As more data becomes available, it may be useful to consider the added upward force caused by the brine by using the SEAWAT-2000 module (Langevin et al. 2003).

Vertical flow would be perpendicular to the general tendency for sedimentary layers to have higher horizontal than vertical conductivity. Fractures and improperly abandoned wells would provide pathways for much quicker vertical transport than general advective transport. This paper considers the fractures as vertical columns with cells having much higher conductivity than the surrounding bedrock. The cell discretization is fine, so the simulated width of the fracture zones is realistic. Dual porosity modeling would not be useful because high velocity vertical flow through the fractures is unlikely. MODFLOW-2000 has a module, MNW (Halford and Hansen 2002), that could simulate flow through open bore holes. Open boreholes would clearly provide rapid transport if the head deep in the borehole exceeds that near the surface or if fractures containing fracking fluid intersect or come close to the borehole. Because it is possible to simply plug open boreholes, I have limited consideration here to fractures; however, models of well fields should include known boreholes.

The thickness of the formations and fault would affect the simulation, but much less than the several-order-of-magnitude variation possible in the shale properties. The overburden and shale thickness were set equal to 1500 and 30 m, respectively, similar to that observed in southern New York. The estimated travel times are proportional for thicker or thinner sections. The overburden could be predominantly sandstone, sections of shale, mudstone, and limestone could exert local control. The vertical fault is assumed to be 6 m thick.

There are five conceptual models of flow and transport of natural and post-fracking transport from the level of the Marcellus shale to the near-surface to consider with an interpretative numerical model.

1. The natural upward diffuse flow due to a head drop of 30 m from below the Marcellus shale to the ground surface, considering the variability in both shale and overburden K. This is a steady state solution for upward advection through a 30-m thick shale zone and 1500-m overburden and is a baseline condition for upward flow through unfractured sedimentary rock.
2. Same as number 1, but with a fracture zone connecting level of the shale with the surface. This emulates the conceptual model postulated for flow into the alluvial aquifers near stream channels, the location of which may be controlled by faults (Williams et al 1998). The fault K varies from 10 to 1000 times the surrounding bulk sandstone K.
3. This scenario tests the effect of extensive fracturing in the Marcellus shale by increasing the shale K from 10 to 1000 times its native value over an extensive area. This transient solution starts with initial conditions being a steady state solution from scenario 1. The K in the shale layers increases from 10 to 1000 times at the beginning of the simulation, to represent the relatively instantaneous change on the regional shale hydrogeology imposed by the fracking. This scenario estimates both the changes in flux and the time for the system to come to equilibrium after fracking.
4. As number 3, considering the effect of the same changes in shale properties but with a fault as in number 2.
5. This scenario simulates the actual injection of 13 to 17 million liters of fluid in five days into fractured shale from a horizontal well with and without a fault.

Model Setup

The model domain was 150 rows and columns spaced at 3 m to form a 450 m square (Figure 3) with 50 layers bounded with no flow boundaries. The 30-m thick shale was divided into 10 equal thickness layers from layer 40 to 49. The overburden layer thickness varied from 3 m just above the shale to layer 34, 6 m layer 29, 9 m to layer 26, 18 m in layer 25, 30 m to layer 17, 60 m to layer 6, 90 m to layer 3, and 100 m in layers 2 and 1

The model simulated vertical flow between constant head boundaries in layers 50 and 1, as a source and sink, so that the overburden and shale properties control the flow. The head in layers 50 and 1 was 1580 and 1550 m, respectively, to create an upward gradient of 0.019 over the profile. Varying the gradient would have much less effect on transport than changing K over several orders of magnitude and was therefore not done.

This simulation considers particle travel times between the top of the shale and the top of the model domain based on an effective porosity of 0.1. A 6-m wide fault is added for some scenarios in the center two rows from just above the shale, layer 39 to the surface. The fault is an attempt at considering fracture flow, but the simulation treats the six meter wide fault zone as homogeneous, which could underestimate the real transport rate in fracture-controlled systems. The simulation also ignores diffusion between the fracture and the adjacent shale matrix (Konikow, 2011).

Scenario 5 simulates injection using a WELL boundary in layer 44, essentially the middle of the shale, from columns 25 to 125 (Figure 3). It injects 15 million liters over one 5-day stress period, or 3030 m^3/d into 101 model cells at the WELL. The modeled shale K was changed to its assumed fracked value at the beginning of the simulation. Simulating high rate injection generates very high heads in the model domain, similar to that found simulating oil discharging from the well in the Deepwater Horizon crisis (Hsieh, 2011) and water quality changes caused by underground coal gasification (Contractor and El-

Didy 1989). DRAIN boundaries on both sides of the WELL simulated return flow for sixty days after the completion of (Figure 3), after which the DRAIN was deactivated. The sixty days were broken into four stress periods, 1, 3, 6, and 50 days long, to simulate the changing heads and flow rates. DRAIN conductance was calibrated so that 20% of the injected volume returned within 60 days to emulate standard industry practice (Alleman 2008; NYSDEC 2009). Recovery, continuing relaxation of the head at the well and the adjustment of the head distribution around the domain, occurred during the sixth period which lasted for 36,500 days, a length of time that simulation of scenarios 3 and 4 indicated would suffice.

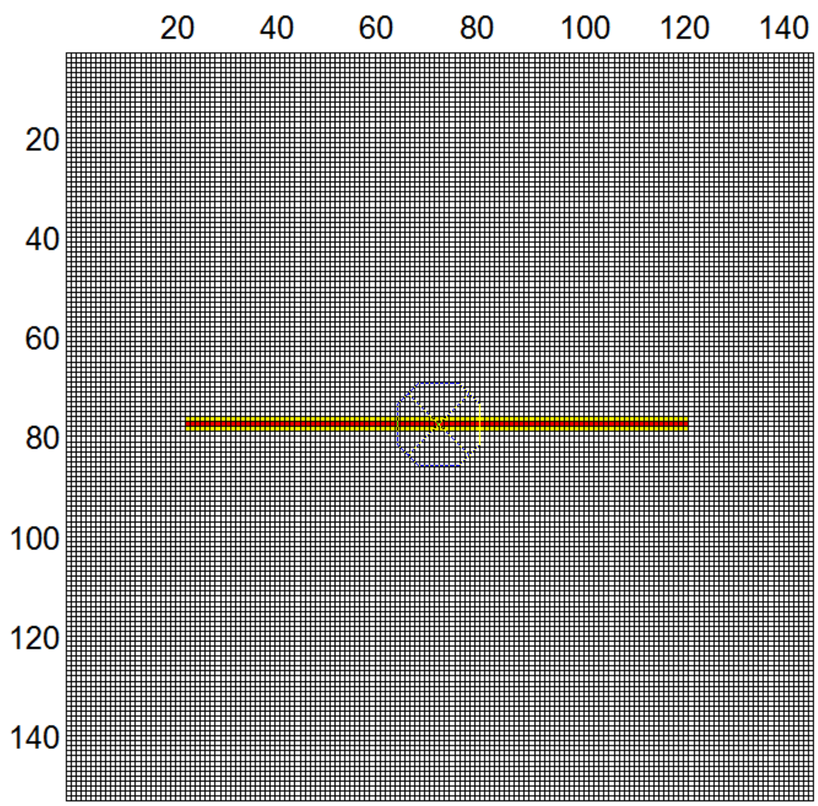

Figure 4: Model grid through layer 44 showing the horizontal injection WELL (red) and DRAIN cells (yellow) used to simulate flowback. The figure also shows the monitoring well.

There is no literature guidance to a preferred value for fractured shale storage coefficient, so I estimated S with a sensitivity analysis using scenario 3. With fractured shale K equal to 0.001m/d, two orders of magnitude higher than the in-situ value, the time to equilibrium resulting from simulation tests of three fractured shale storage coefficients, 10^{-3}, 10^{-5}, and 10^{-7} m^{-1}, varied twofold (Figure 4). The slowest time to equilibrium was for S=10^{-3} m^{-1} (Figure 4), which was chosen for the transient simulations because more water would be stored in the shale and flow above the shale would change the least.

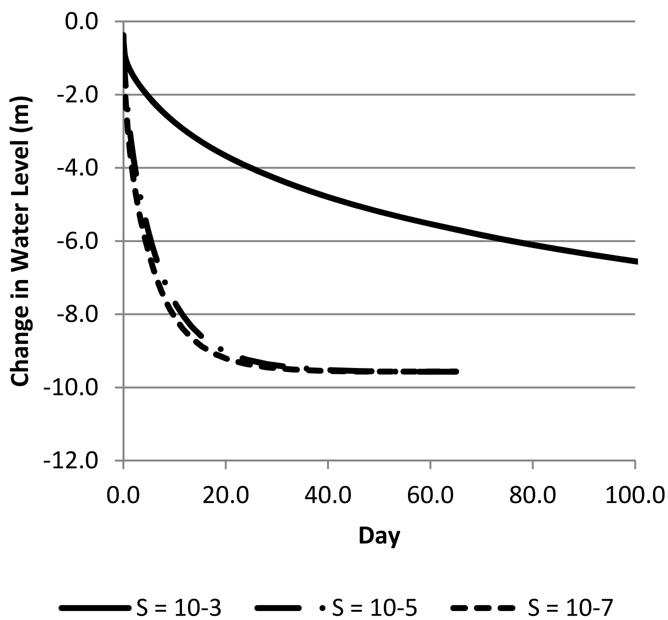

Figure 5: Sensitivity of the modeled head response to the storage coefficient used in the fractured shale for model layer 39 just above the shale.

Results

Scenario 1

The travel time for a particle to transport through 1500 m of sandstone and shale equilibrates with one of the formations controlling advection (Figure 5). For example, when the shale K equals $1x10^{-5}$ m/d, transport time does not vary with sandstone K. For sandstone K at 0.1 m/d, transport time for varying shale K ranges from 40,000 years to 160 years. The lower travel time estimate is for shale K similar to that found by Schulze-Makuch et al. (1999). The shortest simulated transport time of about 20 years results from both the sandstone and shale K equaling 1 m/d. Other sensitivity scenarios emphasize the control exhibited by one of the media (Figure 5). If shale K is low, travel time is very long and not sensitive to sandstone K.

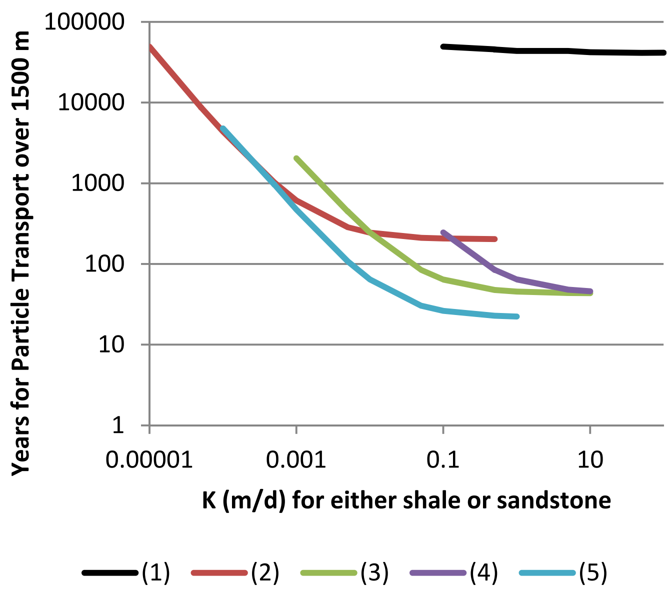

Figure 6: Sensitivity of particle transport time over 1500 m for varying shale and sandstone vertical K. Effective porosity equals 0.1. (1) – varying Kss, Ksh=10-5 m/d, (2) – varying Ksh, Kss= 0.1 m/d, (3) – varying Kss, Ksh = 0.1 m/d, (4): varying Kss, Ksh = 0.01 m/d, and (5): varying Ksh, Kss= 1.0 m/d.

Scenario 2

Vertical transport time through a system including a high-K fault zone was limited primarily by the shale K, presumably because the fault K was one to two orders of magnitude more conductive than that of the surrounding sandstone (Figure 6). Including a fault increased the particle travel rate by about 10 times (compare Figure 8 with Figure 6). The fault K controlled the transport rate for shale K less than 0.01 m/d. A highly conductive fault could transport fluids to the surface in as little as a year for shale K equal to 0.01 m/d (Figure 6).

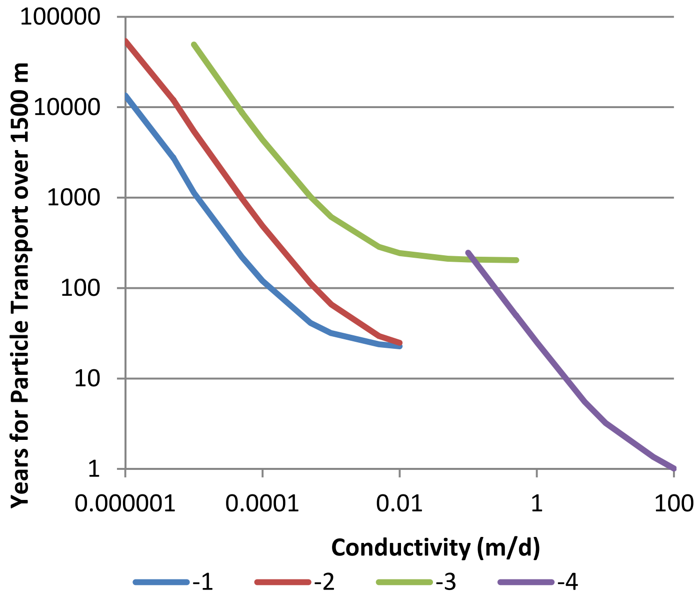

Figure 7: Variability of transport through various scenarios of changing the K for the fault or shale. Effective porosity equals 0.1. (1): Vary Ksh, Kss=0.01 m/d; (2): Varying Ksh, Kss=0.1 m/d; (3), no fault; (4): Varying K fault, Kss=0.1 m/d, Ksh=0.01 m/d. Unless specified, the vertical fault has K=1 m/d for variable shale K.

Scenarios 3 and 4

Scenarios 3 and 4 estimate the time to establish a new equilibrium for scenarios 1 and 2. Equilibrium times would vary by model layer as the changes propagate through the domain, and flux rate for the simulated changes imposed on natural background conditions. The fracking-induced changes cause a significant decrease in the head drop across the shale and the ultimate adjustment of the potentiometric surface to steady state depends on the new shale properties.

The time to equilibrium for one scenario 3 simulation, shale K changing from 10^{-5} to 10^{-2} m/d with sandstone K equal to 0.1 m/d, varied from 5.5 to 6.5 years, depending on model layer (Figure 7). Near the shale (layers 39 and 40), the potentiometric surface increased from 23 to 25 m reflecting the decreased head drop across the shale. One hundred meters higher in layer 20, the head increased about 20 m. These changes reflect the decrease in K across the shale. Simulation of scenario 4, with a fault with K=1 m/d, decreased the time to equilibrium to from 3 to 6 years within the fault zone, depending on model layer (Figure 7). Faster transport occurred only in areas near the fault. Highly fractured sandstone would allow more vertical transport, but diffused advective flow would also increase so that the base sandstone K would control the overall rate.

The flux across the upper boundary changed within 100 years for scenario 3 from 1.7 to 345 m^3/d, or 0.000008 m/d to 0.0017 m/d. There is little difference in the equilibrium fluxes between scenario 3 and 4 indicating that the fault primarily affects the time to equilibrium rather than the long-term flow rate.

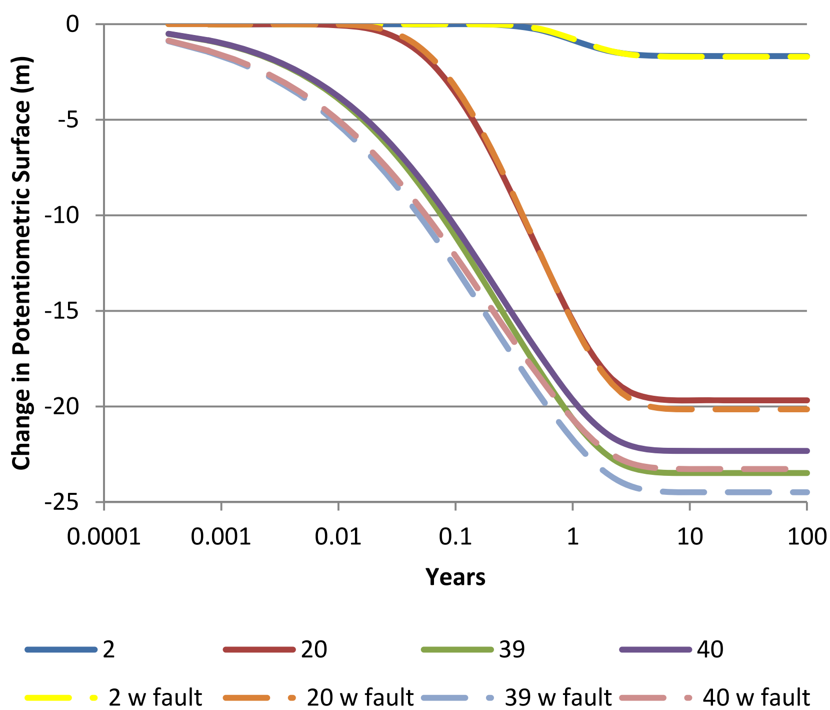

Figure 8: Monitoring well water levels for specified model layers due to fracking of the shale; monitor well in the center of the domain, including in the fault, K of the shale changes from 0.00001 to 0.01 m/d at the beginning of the simulation.

Scenario 5: Simulation of Injection

The injection scenarios simulate 15 million liters entering the domain at the horizontal well and the subsequent potentiometric surface and flux changes throughout. The highest potentiometric surface increases (highest injection pressure) occurred at the end of injection (Figure 8), with a 2400 m mound at the horizontal well. The peak pressure simulated both decreased but occurred longer after the cessation of injection with distance from the well (Figure 8). The pressure at the well returned to within a meter of pre-injection levels in about 95 days (Figure 8). After injection ceases, the peak pressure simulated further from the well occurs longer from the time of cessation, which indicates there is a pressure divide beyond which fluid continues to flow away from the well bore while within which the fluid flows toward the well bore. The simulated head returned to near pre-injection levels slower with distance from the well (Figure 9), with levels at the edge of the shale (layer 40) and in the near-shale sandstone (layer 39) requiring several hundred days to recover. After recovering from injection, the potentiometric surface above the shale increased in response to flux through the shale adjusting to the change in shale properties (Figure 9), as simulated in scenario three. The scenario required about 6000 days (16 years) for the potentiometric surface to stabilize at new, higher, levels (Figure 9). Removing the fault from the simulation had little effect on the time to stabilization, and is not shown.

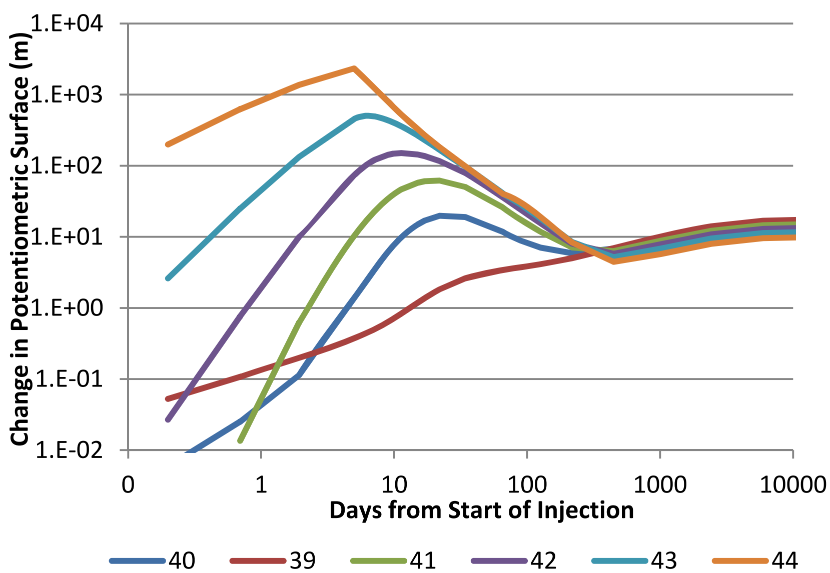

Figure 9: Simulated potentiometric surface changes by layer for specified injection and media properties; Kss=0.01 m/d, Ksh = 0.001 m/d, Kfault = 1 m/d. S(fractured shale) = 0.001 m^{-1}, S(ss) = 0.0001 m^{-1}

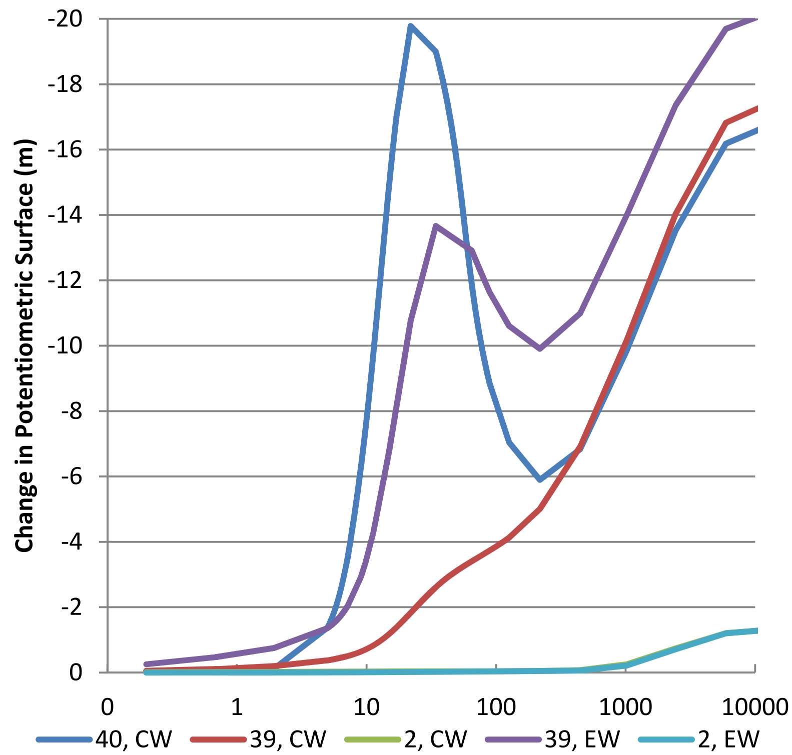

Figure 10: Simulated potentiometric surface changes for layers within the shale and sandstone. CW is center monitoring well and EW is east monitoring well, about 120 m from the centerline. Fault is included. The line for Layer 2, CW plots beneath the line for Layer 2, EW. Kss = 0.01 m/d, Kshale = 0.001 m/d, Kfault=1m/d, S(fractured shale) = 0.001 m^{-1}, S(ss) = 0.0001 m^{-1}

Prior to injection, the steady flow for in-situ shale ($K=10^{-5}$ m/d) was generally less than 2 m^3/d and varied little with sandstone K (Figure 5). Once the shale was fractured, the sandstone controlled the flux which ranges from 38 to 135 m^3/d as sandstone K ranges from 0.01 to 0.1 m/d (Figure 10), resulting in particle travel times of 2390 and 616 years, respectively. More conductive shale would allow faster transport (Figure 8). Adding a fault to the scenario with sandstone K equal to 0.01 m/d increased the flux to about 63 m^3/d with 36 m^3/d through the fault (Figure 10) and decreased the particle travel time to 31 from 2390 years. The fault properties control the particle travel time, especially if the fault K is two or more orders of magnitude higher than the sandstone.

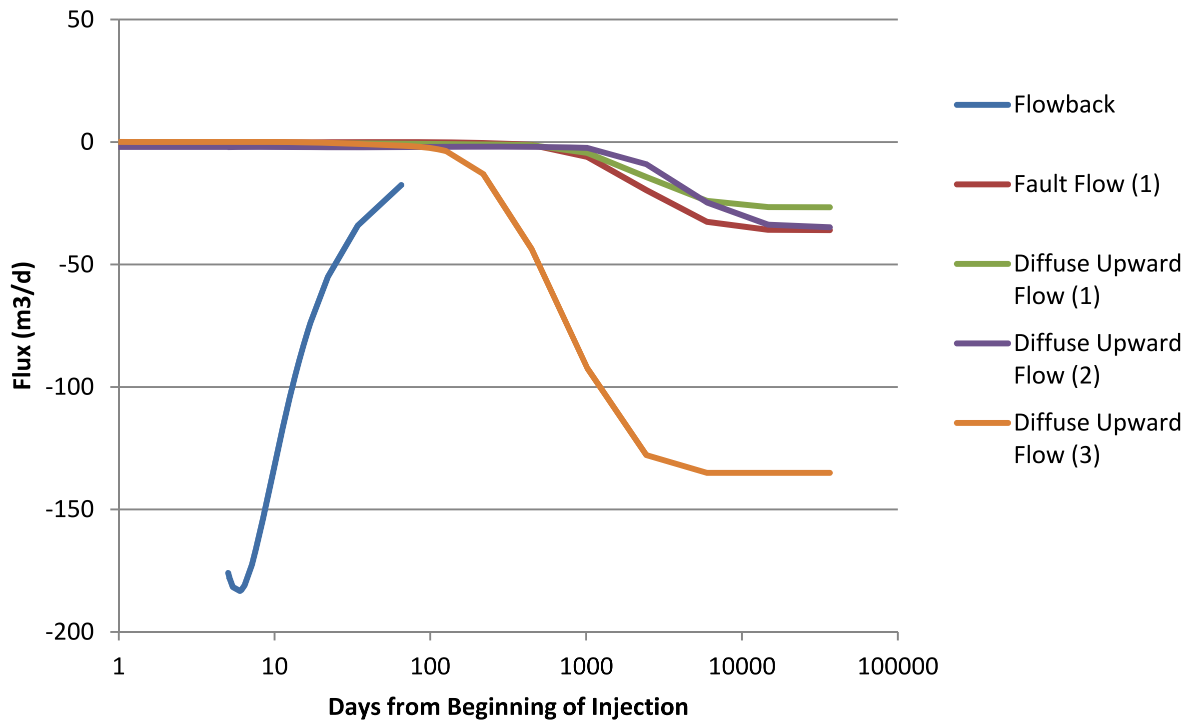

Figure 11: Various fluxes for three separate scenarios. Flowback is the same for all scenarios. (1): Kss=0.01 m/d, Kshale = 0.001 m/d, Fault K = 1 m/d; (2): Kss = 0.01 m/d, Kshale = 0.001 m/d, no fault; (3) Kss= 0.1 m/d, Kshale = 0.001 m/d, no fault.

Simulated flowback varied little with shale K because it had been calibrated to be 20 percent of the injection volume. A lower storage coefficient or higher K would allow the injected fluid to move further from the well, which would lead to less flowback. Lower K would also lead to higher injection pressure which in turn would fracture the shale more.

Vertical flux through the overall section with a fault varies significantly with time, due to the adjustments in potentiometric surface. One day after injection, vertical flux exceeds significantly the pre-injection flux about 200 m above the shale (Figure 11). After 600 days, the vertical flux near the shale is about 68 m^3/d and in layer 2 about 58 m^3/d; it approaches steady state through all sections after 100 years with flux equaling about 62.6 m^3/d. The 100-year steady flux is about 61.5 m^3/d higher than the pre-injection flux because of the changed shale properties.

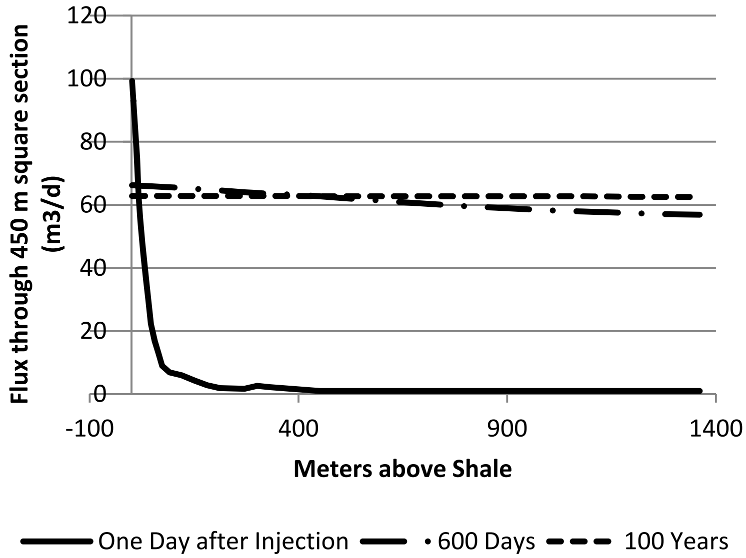

Figure 12: Upward flux across the domain section as a function of distance above the top of the shale layer. Cross section is 202,500 m^2.

Discussion

The interpretative modeling completed herein has revealed several facts about fracking. First, MODFLOW can be coded to adequately simulate fracking. Simulated pressures are high, but velocities even near the well do not violate the assumptions for Darcian flow. Second, injection for five days causes extremely high pressure within the shale that decreases with distance from the well. The time to maximum pressure away from the well lags the time of maximum pressure at the well. The pressure drops back to close to its pre-injection level at the well within 90 days, indicating the injection affects the flow for significantly longer periods than just during the fracking operation. Although the times may vary based on media properties, the difference would be at most a month or so, based on the various combinations of properties simulated. The system transitions within six years due to changes in the shale properties. The same order of magnitude would apply to changes in shale properties from less to more conductive. The equilibrium transport rate would transition from a system requiring thousands of years to one requiring hundreds of years or less within less than ten years.

Third, most of the injected water in the simulation flows vertically rather than horizontally through the shale. This reflects the higher sandstone K 20 m above the well and the no flow boundary within 225 m laterally from the well, which emulates in-situ shale properties that would manifest at some distance in the shale.

Fourth, the interpretative model accurately and realistically simulates long-term steady state flow conditions, with an upward flow that would advect whatever conservative constituents exist at depth. Using low, unfractured K values, the transport simulation may correspond with advective transport over geologic time although there are conditions for which it would occur much more quickly (Figure 5). If the shale K is 0.01 m/d, transport could occur on the order of a few hundreds of years. Faults through the overburden could speed the transport time considerably. Reasonable scenarios presented herein suggest the travel time could be decreased further by an order of magnitude.

Fifth, fracking increases the shale K by several orders of magnitude. The regional hydrogeology changes due to the increased K. Vertical flow could change over broad areas if the expected density of wells in the Marcellus shale region (NYSDEC 2011) actually occurs.

Sixth, fault fracture zones coming close to contacting the newly-fractured shale could allow contaminants to reach surface areas in tens of years. Faults can decrease the simulated particle travel time several orders of magnitude.

Conclusion

Fracking can release fluids and contaminants from the shale either by changing the shale hydrogeology or simply by the injected fluid forcing other fluids out of the shale. The complexities of contaminant transport from hydraulically fractured shale to near-surface aquifers render estimates uncertain, but a range of interpretative simulations suggest that transport times could be decreased from geologic time scales to as few as tens of years. Preferential flow through fractures could further decrease the travel times to as little as just a few years.

There is no data to verify either the pre- or post-fracking properties of the shale. The evidence for potential vertical contaminant flow is strong, but there are also almost no monitoring systems that would detect contaminant transport as considered herein. Several improvements could be made.

- Prior to hydraulic fracturing operations, the subsurface should be mapped for the presence of faults and measurement of their properties
- A reasonable setback distance from the fracking to the faults should be established. The setback distance should be based on a reasonable risk analysis of fracking increasing the pressures within the fault.
- The properties of the shale should be verified, post-fracking, to assess how the hydrogeology will change.
- A system of deep and shallow monitoring wells and piezometers should be established in areas expecting significant development, before that development begins (Williams 2010).

Acknowledgements

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Appendix C

Review of NYSERDA Commissioned Review of Myers Comments on the 2009 DSGEIS

Prepared by: Tom Myers

11/30/11

Introduction

The New York State Energy and Resource Development Agency (NYSERDA) commission Alpha Geosciences (Alpha) to complete a review of the comments I had prepared for the 2009 Draft Supplemental Generic Environmental Impact State (DSGEIS). This report replies to some of those review comments. Throughout, I refer to the review as “Alpha”.

General Points

Alpha divided my comments into various subsets for their response, but they rely very much on several points throughout their response. One is their perception of there being no hydraulic connection between groundwater at depth, in the Marcellus shale, and the near-surface aquifers; they also dismiss the analysis from ICF (2009) on the same basis, even though they have no data with which to dismiss the argument. Their second line of reasoning is the results or conclusions from the 2004 EPA study of coal bed methane fracking.

Alpha rejects the suggestion that a water balance for the project area or subareas “would not serve the purpose of the SGEIS” (Alpha, at 4). They provide no reason for this conclusion, but also state that a “water balance clearly is site-specific” (Id.). A water balance can be useful for any size study area or portion of the study area. A water balance for the overall study area would help to understand the total volume of water involved in fracking; a similar argument can be made for a watershed – a water balance for the groundwater would help to understand whether the water amounts used for fracking is a substantial portion of the local water balance.

Alpha partially rejects my suggestion that a better description of the area’s hydrogeology is needed by quoting my statement that “the Marcellus Shale is ‘notoriously heterogeneous’” (Alpha, at 4). The request for a better description pertains to the overall area, not specifically the Marcellus shale. Additionally, the statement supports the concept that reported permeability values for the shale may not be representative and that broader scale description are required.

Hydraulic Connection between Shale and Surface

Alpha argues that the “target shales exist as an isolated system from the overlying fresh water-bearing units” (Alpha, at 4). “Isolated” overstates the case even for natural conditions, although the connection may be limited, as I accepted in 2009. Alpha claims that the “shales … are not part of, and are not connected to, the regional hydrogeological systems. Their baseline geologic evidence that fluid migration to overlying fresh water aquifers is improbable includes studies that show the Marcellus shale has remained isolated from overlying formations for millions of years" (Alpha, at 5). Alpha does not directly provide citations for these "studies", but in the next sentence references the "facts that these units are 'overpressured' and that natural gas and saline water has remained trapped … for millions of years" (Id.) to two industry studies and the GEIS. This all ignores the science, cited in Myers (in review) of the upward movement and artesian pressure, observed during geothermal exploration, in formations above the shale. The salt in the shale may be the source of the salt in overlying formations, with the upward movement of salt balanced by the downward movement of freshwater recharge. This balance could be substantially upset by the changes wrought by fracking on the shale.

The "overpressuring" of the shale does not prove that the shale itself is isolated. Overpressuring is due to the gas being contained in the low permeability, very small pore spaces of the shale. Once fracked, the overpressuring may provide an initial source for water to flow into the formations above the shale.

The isolation argument is invoked again, by Alpha, at 11&12, 20, and 33.

My discussion relied and continues to rely for the 2011 rDSGEIS on the fact that fracking will change those conditions, changing the shale from an almost impervious aquitard into a low-conductivity formation; the previously isolated formation water will no longer be "isolated" because fracking fluid injection will push some into surrounding formations. The "overpressuring" in the shale may suggest that the shale itself is isolated at least in places. Myers' (2009 and in review) argument relies on the connection in the formation above the shale. Once fracked, the shale will have a much higher permeability so that fluids in the shale can move into surrounding formations within which the general groundwater flow will control.

Alpha refers to the fact that shallow water wells may be hydrofractured as "additional evidence that natural fractures and structures are not necessarily transmissive" (Alpha, at 4 and 37). This is a comparison of "apples and oranges". Hydrofracturing water wells may be done to increase their yield when screened in low-transmissivity formations; fracking water wells is done to increase the well yield from a few gallons per minute. The transmissivity of unfracked shale is orders of magnitude less than that in the formations in which a water well may have been screened. The cause for fracking in water wells differs from the cause for fracking a gas well; the comparison is irrelevant and proves nothing about the isolated nature of shale.

A further reliance on "overpressuring" is demonstrated (Alpha, at 5) where Alpha notes that eight research wells in the Marcellus shale had pressure gradients of 0.46 to 0.51 psia/ft when hydrostatic pressure is 0.433 psia/ft. That waters remain contained in the shale even with this overpressuring demonstrates their isolation. Once fracking hydraulically connects the shale with the overlying formations, the overpressuring is a source of pressure that would cause an upward gradient. The pressure would likely dissipate with time, but it would also cause an upward gradient after fracking.

Alpha indicates that my “hypothetical pathway … to ground water is along faults and fractures that intersect the Marcellus or induced fractures that extend beyond the target formation” (Alpha, at 5). This mischaracterizes the argument in two ways. First, it ignores the potential flow through the bulk media, through the primary porosity of the formations; this pathway would be slower, but flow is possible if there is a connection (Myers, in review) with the newly fractured shale. Myers (in review) found this flow to require from 100s to 1000s of years for contaminant transport. Second, natural faults and fractures do not have to “intersect” the shale, just reach its edge. Fluids within the shale would access the natural fractures above the shale, once fracked; the overpressuring would provide an added gradient for flow from the shale to surrounding formations, once fracking releases the fluids.

Alpha’s second point is correct; out-of-formation fractures would provide an additional pathway. Although Alpha continues to suggest that out-of-formation fracking is rare, in their view, more current evidence is that it occurs frequently and extends as much as 2000 feet above the target formation (Fischer 2010); Alpha even references a personal communication from Fisher (Alpha, at 24) to recommend that the “SGEIS acknowledge that hydrofracturing has been shown to induce fractures beyond the target formation” (Id.). It appears that Alpha is not familiar with up to date literature or science.

Alpha rejects the “suggestion of ‘head level maps’” that I had suggested in 2009 based on their rejection of the concept of saturated conditions from the “top of the target zone to the land surface” (Alpha, at 20). If there is no connection, groundwater levels will show nothing. They also note the isolation argument (at 20, 21) to reject the need for head level maps. Head level maps as recommended by Myers (2009) would confirm or deny the presence of upward head gradients in the formations above the shale. Once released by fracking, contaminants could advect along the flow paths which would be delineated by the hydraulic gradient. Although the fracking itself will change the gradient and potentially increase the potential upward flow, mapping the groundwater levels would assist the NYSDEC in determining where transport is possible. Alpha’s recommendation is to basically ignore science and ignore the possibility of upward flow. Alpha replied to my comment suggesting that the rDSGEIS discuss properties resulting from fracking by discussing the direction that fractures would take in the shale (Alpha, at 15). My comments indicated that the rDSGEIS should include hydrogeologic properties, therefore Alphas reply was not responsive to the comment. Alpha’s response that my “argument that the fractures will extend to and connect overlying fractures or paleofractures contradicts rock mechanics principles and field observations” is countered by the recent data in Fisher (2010) showing out-of-formation fracking. Alpha is unclear and provides no references as to how the comments contradict “rock mechanics principles”.

I had also recommended that the NYSDEC require the industry to monitor post fracking shale properties. Alpha states that “[f]racture monitoring is required by the Proposed Supplementary Permit Conditions … (#33 and #34)” (Alpha at 16). That is incorrect; those permit conditions require the driller report on recorded operations during fracking, including pressure and the amount of injected, but that is not the same thing as doing post-frack monitoring, which could include microseismic surveys or core sampling. They also suggest that “[f]racture monitoring also can be evaluated on a well-specific basis using the same criteria as the requirement to collect core samples and well logs" (Alpha, at 16). Those requirements are for pre-fracking conditions, not post-fracking.

Myers' Groundwater Modeling and ICF Analytical Modeling

I prepared (Myers 2009) an interpretative numerical groundwater model to consider whether and over what time frame flow could occur from the shale to freshwater aquifers. The "theory supporting Myers' model" is NOT from Hill and Tiedeman (2007) (Alpha, at 23). The reference is to the concept of "interpretative" modeling as opposed to a calibrated, predictive model. "Myers acknowledges that his model is not calibrated and cannot be used for predictive purposes" (Alpha, at 12). An interpretative model is not used for prediction, so Alpha's attack on the model is an attack here is irrelevant. The model does assume that the interburden between the ground surface and top of the shale is saturated, but not through the "isolated shale gas formations" (Id.). Again, the modeling is of the interburden and the shale, once it is fracked to its edge or beyond, is a boundary or a source of both fluids and contaminants. Or, flow through the shale is estimated based on its extremely low in-situ conductivity.

The numerical model I used in 2009 was not "to support [my] opinion" (Id.) but to test my conceptualization as to whether the flow was possible and under what conditions. Alpha criticizes the fact the model "oversimplifies ground water flow and transport". All groundwater models simplify flow; simple applications of Darcy's law are the most oversimplified analyses. The addition of secondary permeability, or fracture flow, to a contaminant transport analysis usually increases the rate that contaminants move, thus my estimated times should be low.

Alpha asserts that my "offered alternate model is not technically defensible" apparently based on their perceived lack of a hydraulic connection. They state that an assumption of a hydraulic connection "contradicts decades of hydrofracturing data and experience in the U.S." (Alpha, at 11) without referencing or outlining the data in support of their contention. They also claim that my analysis is based on "the entire bedrock stratigraphic column [being] highly fractured" (Alpha, at 12). This statement does not reflect the analysis in Myers (2009), for reasons noted above - the conductivity values used for the formations between the shale and surface were based on observed primary conductivity values (Anderson Woessner 1992), not fractured values.

ICF's flow equations are correct (Alpha at 11), but the problem is how they were parameterized and time frame they were applied over. As Myers (2009) discussed, the relevant gradient is not from the well to the aquifers, but from the well to just beyond the influence of the spreading injected fracking fluid, the point at which the background pressure has not changed. Also, the conductivity parameters for the formations between the shale and the aquifers do not reflect fractures, unless specifically parameterized as such. The parameters reflect standard textbook bulk conductivity values for sandstone.

Vertical Contaminant Transport

I had argued that "natural gradients" would allow vertical contaminant transport of frack fluid through advection. Alpha claims that "Engelder refutes that injected frac water would migrate vertically upward in his slide-presentation review of others” (Alpha, at 24). Aside from the confusing phrase, “slide-presentation review of others”, this line of reasoning cannot be correct because frack fluid is lighter than the high-TDS brine found in the shale; buoyancy due to frack fluid being lighter than brine would enhance its upward movement. The movement of high-TDS formation water could be inhibited by its denser nature, but the point is that upward hydraulic gradients cause the flow. The overpressuring discussed above is proof of these upward gradients and suggestive that fracking would release some of this pressure into the formations lying above.

Engelder’s “principle of viscosity” (Id.) may apply “to ground water as well as gases”, but the fact that low viscosity gases have been contained from vertical migration for millions of years does not mean that fracking will not release contaminants that could migrate upward much quicker. The relevant “containment” is provided in the shale and has nothing to do with the properties of overlying formations. Shale has contained gas for millions of years; fracking will cause that gas to be released in 30 to 50 years (the length of time most wells will produce). This can only occur if the properties that contain the gas will vastly change.

Leaks from Well Bores

The DSGEIS had implied that leaks do not occur from properly-constructed wells, but did not specify how often wells are found to not be properly constructed, and I requested (Myers 2009) that they provide an estimate of the times the wells are not properly constructed. Alpha responded with a quote from an industry source that estimated risk from failures to properly constructed wells is less than one in 50 million (Alpha, at 32). Alpha should have included the entire paragraph from which they selectively chose their quote, because it indicates the wells considered are class II injection wells and are properly constructed. Fracking wells experience a much higher, although much shorter, pressure during operations. They also should realize that the comment had to do with wells that are improperly constructed, because most failures, those that have allowed gas into groundwater, have resulted from improperly constructed wells.

Alpha also protests too much when they discuss my examples of gas in water wells (Alpha, at 33, 34). Incidents not related specifically to fracking are relevant because they show that the gas does move long distances through the groundwater, regardless of the source. Coal bed methane development relies on the gas moving through the groundwater, in coal seams, to the production wells; those production wells commonly pump as much water as do water wells, so, if gas is present to move to the water wells, the conceptual model for flow to water wells is similar. The point has to do with gas moving through aquifers due to any source – direct from the shale or a leak from the well bore.

Comparison to CBM Wells

Alpha used the conclusion to the EPA’s 2004 CBM study, that fracking in coal seams poses little or no threat to underground sources of drinking water (Alpha, at 20) to support their conclusion that I had ignored relevant data (EPA’s study) and that my arguments were fallacious because CBM wells are a much higher risk. They also state that “[c]oalbed hydrofracturing events approximate conditions where shale hydrofracturing is performed closest to ground water resources” (Id.). This is simply not true, and it directly contradicts the conditions that the EPA put on their conclusion. EPA relied on the nature of CBM wells for their conclusion. "Although potentially hazardous chemicals may be introduced into USDWs when fracturing fluids are injected into coal seams that lie within USDWs, the risk posed to USDWs by introduction of these chemicals is **reduced significantly by groundwater production and injected fluid recovery**, combined with the mitigating effects of dilution and dispersion, adsorption, and potentially biodegradation" (EPA, 2004, at 7-5, emphasis added).

In fracked shale, there is no intentional "injected fluid recovery" brought about by pumping the injection wells, as in CBM wells. CBM wells pump water toward the gas well; this pumping decreases the hydrostatic pressure which releases the gas from the coal. Water and contaminants in the coal seam flows toward the CBM well. If there were contaminants in the coal, they would be drawn toward the CBM well.

Fracking in a coal seam would require much less pressure as well which would cause less out-of-formation fractures, which would limit the chance for out-of-formation fractures to occur. Additionally, EPA relies on the "high stress contrast between adjacent geologic strata" as a barrier to fracture propagation. The fact the coal is softer and the seams are much shallower and require much less fracking pressure helps to limit the fractures to the coal, much in contrast to shale seams (Fisher, 2010).

Finally, although the EPA's reasoning is reasonable, their methodology for concluding there has been no contamination is suspect; they only considered reported cases of contamination rather than relying on monitoring data. Fracking fluids in water wells near coal seams would be reported only if someone detects a problem. There have been cases of methane reaching water wells in the coal seams, but methane is obvious as it bubbles coming from the faucet.

Alpha claims that "Myers fails to address the historical data presented by ICF (2009, p. 22)" (Alpha at 19). ICF (2009, p 22) does not actually present data, contrary to Alpha's allegation. GWPC (1998), the source of ICF's "data", presents the results of a survey to which officials from states with over 10,000 coal-bed methane wells had responded they had never found groundwater contamination. However, contrary to Alpha's allegation, GWPC did not analyze 10,000 wells' worth of data. GWPC does not present monitoring data as proof, they present survey data from agency personnel claiming there has been no reported contamination. There is no indication whether the agencies ever looked for contamination beyond the claims of well owners. ICF also notes that coal seams may be used as aquifers, but did not indicate how many of the coal seams being developed by the CBM wells in the states replied to by the agency personnel were also aquifers.

Alpha truly mixes apples and oranges by using studies of CBM development, including fracking, to conclude that shale-gas development poses no threat to groundwater.

General Hydrogeology

Alpha's response to comments regarding aquifer depletion is a stretch to show how they actually disagree with my comments. Specifically, my comments about failures to regulate are replied to by stating the various commissions must permit the withdrawal – the problem is that there are really no specifics provided about how the decision to permit would be granted. The DSGEIS did not specify what standard had to be met, beyond simple reporting, to be granted a permit.

Mitigating Surface Water Impacts

Alpha goes out of its way to find something to criticize in its review of my general surface water comments (Alpha, at 44, 45). My comments were generally qualitative and Alpha's responses are generally not substantial enough to require a reply here.

In Alpha section 4.2, regarding the use of the natural flow regime method, Alpha states that I was incorrect in claiming the NYSDEC would not require its use (Alpha, at 48). The 2011 rDSGEIS states clearly that it is NYSDEC's intent to require use of the NFRM, but the 2009 DSGEIS only states that it is "preferred", not required (2009 DSGEIS, at 7-3).

Alpha responds in detail to my comments regarding the Delaware and Susquehanna River Basin Commissions' methods (Alpha at 46, 47), even though they acknowledge the dSGEIS would require the NFRM. Because the rDSGEIS states the NFRM will be used throughout the project area, there is little reason to reply further to Alpha's comments at this point.

Ultimately, Alpha adapts many of my recommendations regarding surface water flow (Alpha, at 50, 51). They do not specifically endorse the recommendation to minimize the effect on aquatic habitats (outlined at Alpha, p. 47), the RDSGEIS does adapt a recommendation for using the Q60 or Q75 flow by month, which by month is better than my original recommendation.

Setbacks

Alpha discusses vertical setbacks along with my comments on monitoring and the need for water level mapping (Alpha, section 3.1). Much of their response relies on their perceived lack of hydraulic connection among formations, which has been discussed above.

Regarding horizontal setbacks, I had suggested that the recommended values are not based on any data or analysis of their effectiveness. Alpha simply rejects this without providing any reference, data, or results. "Myers assumes the setbacks proposed in the dSGEIS are not based on analysis; however, the setbacks are supported by practical application, experience, and historical analyses" (Alpha, at 43). Alpha repeats this sentence twice, verbatim, on the same page. When stating something as being based on analyses, it is customary scientific practice to cite the references to these analyses, something Alpha has failed to do. Alpha also suggests the "dSGEIS reference SEQRA, NYSDOH, NYC Watershed Rules and Regulations, the Clean Water Protection Act, and public water protection rules from other states" (Id.). Alpha does not indicate where in the dSGEIS these references are made, not indicates that the references include any analysis. Referencing others' rules without analyzing their effectiveness is not a scientific justification for specifying a setback. My statements are not that the setbacks are wrong, but that it is unknown whether they are effective. My recommendations may be larger than those in the dSGEIS, but they are designed to be protective to encourage a site specific analsis.

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Attachment 3

Glenn Miller, Ph.D.

Review of the

Revised Draft
Supplemental Generic Environmental Impact Statement on The Oil, Gas and Solution Mining Regulatory Program
Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

Prepared for:
Natural Resources Defense Council
New York, New York

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This document represents a review of the Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) regarding proposals to develop natural gas wells using high-volume hydraulic fracturing in New York. I have specifically examined some of the chemical and toxicological issues, particularly related to the fracturing additives used, and the management of the severely contaminated flowback/produced brines. The RDSGEIS, in general, is an improved document compared to the previous draft of the potential environmental impact of the very large number of gas wells being proposed in much of New York. However, several key potentially significant adverse impacts remain inadequately addressed.

The following comments should be considered.

A. The water that flows back immediately following hydraulic fracturing is heavily contaminated (flowback), primarily with the Marcellus formation contaminants, and represents the most problematic chemical contamination potential, due to the large volumes of contaminated water generated. The brines that will be produced during gas production[1] will have higher concentrations of naturally occurring contaminants than flowback water (although lower volumes) and similarly represent a serious chemical contamination potential.

The RDSGEIS recognizes these problems and goes a long way towards evaluation and management of the contaminants; however, it still does not present a comprehensive wastewater management and disposal plan that will handle the anticipated large volumes of heavily contaminated wastewater. Further efforts are required to properly understand the contaminants in the flowback water, and develop management and disposal solutions.

Four problematic components of the flowback water and produced brines are present, including: (1) salts, other inorganic constituents, and metals and metalloids; (2) the radioactive component (NORM); (3) organic substances (from the hydrocarbon formation) and (4) hydraulic fracturing chemical additives.

1. ***Salts, other inorganic constituents, metals and metalloids in the formation water that are brought to the surface both as flowback and as production brines*:** The largest mass component of the formation water is salts and other inorganic constituents. The concentration of these constituents varies widely, as does their toxicity. Because the flowback is proposed to be collected and temporarily stored in closed systems, disposal of these large volumes of water is the largest problem with its management. The RDSGEIS discusses the problems with management of this water, and in

[1] The terms produced brine, production brine, produced water, and produced water brine are used interchangeably throughout these comments for formation water that is produced up the well.

particular the discharge of high total dissolved solids (TDS) water into receiving waters (see, for example pages 7-63), and stipulates that flowback produced water and brines will need to be regulated as industrial wastewater.

Table 5-10 of the RDSGEIS shows that produced waters (from Pennsylvania and West Virginia) containing the formation water are variable in chemical composition, but include not only simple salts (e.g., sodium, potassium, chloride, bromide, sulfate, fluoride, etc.) but also a variety of metals with varying frequency (cadmium, mercury, cobalt, nickel) and metalloids (arsenic, selenium, boron). Some of the constituent concentrations are very high, particularly sodium chloride, which has a mean concentration of over 10% by weight. Some samples had over 30% by weight simple salts plus other contaminants. The extreme contamination of these wastewaters and the high variability of contaminant levels make these waters complicated for treatment and potential reuse, as well as for tracking and disposal. If improperly managed and released to surface or groundwater, severe contamination is a reasonably foreseeable outcome. In particular, if this contaminated water intercepts domestic groundwater sources, the potential exists to permanently damage aquifers as current and future domestic water supplies.

While recognizing the problems with management of this water, the RDSGEIS fails to clearly state how this water will be either disposed in a manner that protects human health and the environment, or otherwise treated to remove the contaminants. While the RDSGEIS provides a range of treatment and disposal alternatives, the RDSGEIS does not sufficiently analyze the environmental or human health impacts associated with any of these treatment and disposal options. Further, the RDSGEIS implies that virtually all of the wastewater generated in New York will be managed out of state, where regulations may be less stringent, due to the lack of treatment capacity for these contaminated waters in New York.

2. ***Radioactive Substances (NORM):*** The RDSGEIS also recognizes the issues associated with management of NORM that comes to the surface either in the flowback or the production brines. However, similar to the salt problem discussed above, it does not explicitly indicate how wastes contaminated with NORM will be regulated and disposed.

   Examples of NORM concentrations in flowback are presented in Table 5-24, and in produced brines in Appendix 13. As expected, the NORM present in the flowback is somewhat lower than in the brines, due to dilutions when fresh water is used for the primary fracturing fluids. Less dilution would be expected if the flowback is reused as a portion of the fracturing fluid for another well.

Only three produced brine samples are shown in Appendix 14, but the level of radioactivity as gross alpha is very high, from about 18,000 pCi /L to 123,000 pCi/L. The standard for safe drinking water is 15 pCi/L (gross alpha).

The RDSGEIS does not propose a disposal solution for residual NORM, if it is separated from the produced water and the flowback water. Dilution of the brines to a drinking standard of 15 pCi/L (gross alpha) will require 1000x to 10,000x dilutions, and is unlikely to be acceptable in any jurisdiction, particularly when the components that are causing the radioactivity are not specified. While some mention of regulatory oversight is made in the RDSGEIS, there are no explicit indications of how these waters will be regulated or managed. The RDSGEIS does not propose a technically sound or viable solution for disposing of these radioactive materials. The RDSGEIS has not examined options such as evaporation-crystallization treatment or chemical precipitation. These processes will produce a very large tonnage of salts containing radioactive and metal waste. The lack of a thorough treatment and disposal analysis presents a serious problem when assessing the risk and potentially significant adverse impacts of these substances. There is effectively no analysis of how these materials will be disposed, other than a general (potential) suggestion that new licensing may be required.

For an adequate environmental analysis, it is also critical to identify the sources of the gross alpha radiation. Gross alpha radiation is defined by the U.S. EPA (40 CFR Parts 9, 141, and 142 [National Primary Drinking Water Regulations; Radionuclides; Final Rule]) as the total amount of alpha radiation minus the alpha radiation coming from uranium and radon. Table 2.3 of the RDSGEIS, which specifies the primary drinking water standards, is unclear as to how New York regulates radioactivity, other than to indicate that it will limit “alpha particles” to 15 pCi/L in drinking water, but does not indicate if that includes uranium. For the three samples of groundwater indicated in Appendix 13, only a small fraction of the components of the gross alpha have been identified, with the largest component being ^{226}Ra. For the three samples provided in Appendix 13, the individual gross alpha contributors can be summed to provide only 14-24% of the gross alpha in the water samples. The RDSGEIS does not identify the source of the remaining 76%+ alpha radiation; this omission constitutes a major flaw in the radioactive waste treatment and disposal analysis.

While it may be difficult to get an exact mass balance, accounting for less than 25% of the alpha radioactivity is insufficient.

It is unclear whether the data in Appendix 13 were based on the EPA gross alpha radiation definition, but the implications are substantial. If the EPA gross alpha radiation definition is used (which is probably the case), some other source of the alpha radiation will be present (e.g., polonium) as was observed in the Florida phosphate industry (Burnett, et al., 1988). Verifying radioactive waste constituents is particularly important when assessing radioactive waste risk and to develop viable treatment and disposal options. Radioactive materials will also precipitate as scale in equipment; therefore, verifying radioactive waste constituents is also important for determining the radioactive risk as pipes are disassembled when cleaning is needed, or when the wells are disassembled when gas production ceases. If the source of the excess alpha radiation is polonium, the residual radioactivity from water treatment or scale management will potentially be more expensive to manage safely. The RDSGEIS has not analyzed the polonium risk, or treatment and disposal options for radioactive waste containing polonium.

While the U.S. does not have a polonium 210 standard, both Canada and the European Union do (see accompanying comments of Dr. Ralph Seiler), and it is lower or similar to the U.S. radium standard (5 pCi/L). Polonium is soluble in water under reducing conditions, and should be assumed to contribute to the alpha emission from the formation water, unless NYSDEC can rule out the risk. Polonium's risk contribution, however, is not currently analyzed in the RDSGEIS, and is a critical data gap in the NORM analysis. Polonium is a strong alpha emitter, but most importantly, treatment/management of these waters for disposal should require knowledge of the composition of the alpha emitting NORM component. Only then can appropriate methods for treatment and disposal be developed.

An additional component of the naturally occurring radioactivity is radon, a gaseous odorless radioactive element that is responsible for approximately 21,000 deaths from lung cancer each year (ATSDR, 2012), and is second only to cigarette smoking for causing this disease. Southern New York is already recognized as a region where elevated radon (>4 pCi/L) is common. Adding radon to households either from improperly vented gas utilizing appliances or through water systems that have been contaminated with natural gas leaks in groundwater supplies presents an additional risk factor for radon.

Data on radon in natural gas from the Marcellus Shale formation is very scant, and the RDSGEIS does not contain a sufficient amount of data to verify the maximum concentrations of radon expected in Marcellus Shale gas, or any other natural gas that may be developed under the proposed scope of the SGEIS. The amount of radon in natural gas is a critical measurement that should be made, to examine the incremental risk of radon exposure in homes and places of business that use natural gas or well water that could experience higher radon content as Marcellus and other shale gases are produced in NYS. While normal natural gas use in properly ventilated burners is unlikely to contribute to radon concentrations in closed spaces (see accompanying Seiler report), poorly vented areas may result in increased radon concentrations, and certain scenarios (e.g., high use of natural gas for industrial applications, restaurants that use gas burners) should be subject to risk assessment. The risk of radon exposure from burning natural gas in poorly ventilated areas is likely to be greatest in indoor areas that already have elevated radon exposure levels.

An additional risk is when natural gas from a well leaks into an aquifer used as a well water source. Depending on concentrations of radon in the water, and the use of that water, radon levels can potentially be elevated in homes. This is a separate risk than from burning natural gas, but it is reasonable to develop scenarios where highly radon-contaminated gas moves through the soil profile and into homes. However, there are only scant radon data that can provide a basis for estimating those risks.

Recommendation 1. The SGEIS should clearly identify treatment and disposal options for flowback and wastewater, analyze the range of treatment and disposal alternatives, and propose the best technology and best practices for handling this waste. These technologies and practices should be included in the SGEIS as a mitigation measure, and codified in the NYCRR. The SGEIS treatment and disposal options for flowback and wastewater analysis should include a detailed examination of the waste constituents including, at a minimum: salts and inorganic constituents; NORM; metals and metalloids; organic substances (from the hydrocarbon formation); and fracture treatment additives.

Recommendation 2. The SGEIS should examine the existing wastewater treatment capacity in NYS, compared to the potential volume and composition of wastewater that will be generated by the proposed development, and make specific recommendations to ensure sufficient waste handling capacity exists before authorizing the proposed development. If waste will be transported to other states, the SGEIS should examine the impacts of that waste handling option as well.

Recommendation 3. The components of the gross alpha radioactivity should be identified in the RDSGEIS, and mitigation measures should be proposed to address radioactivity risk. The RDSGEIS does not identify 76%+ of the gross alpha radioactivity. The specific definition of gross alpha radioactivity should also be stated, or the EPA definition should be used.

Recommendation 4. The RDSGEIS should determine whether polonium is a significant component of alpha emission in formation waters, and polonium-contaminated wastewater should be regulated/managed appropriately to limit its discharge to surface or groundwater, as should all of the individual components of NORM.

Recommendation 5. Specific treatment methods to remove radioactive constituents from flowback and produced water need to be identified. If the radioactive constituents are removed from wastewater, management methods and disposal sites for the residual radioactive wastes should be identified. (See further discussion below.)

Recommendation 6. Additional radon measurements are needed to determine the range of concentrations of radon expected in Marcellus Shale gas or any other gas that may be developed under the proposed scope of the SGEIS. Gas measurement should be made at the wellhead, where natural gas is being used, including homes, businesses that use large amounts of natural gas, and in areas where natural gas leaks have been found. The SGEIS should include radon testing requirements as a mitigation measure, and this requirement should also be codified in the NYCRR.

3. ***Hydrocarbons present in the formation water:*** Hydrocarbons present in the flowback and produced water are characteristic of fuel hydrocarbons, and are represented by (a) compounds that, in some cases, are carcinogenic (e.g., benzene, benzo(a)pyrene); (b) common solvents (e.g., toluene, ethylbenze); and (c) the primary fuel components of natural gas, particularly methane. Common solvents and primary gas components, although generally of lower solubility in water, represent a toxic contribution that can be a serious risk, if they are released either into surface water or as a vapor that may subject persons living in the area to exposure.

4. ***Hydraulic fracturing additives:*** The range of hydraulic additives is very large, and difficult to assess from a risk perspective since the list is almost certainly incomplete, specific information on the chemicals is lacking, and the specific rate of usage is not offered. Thus, not knowing the composition of the specific additives and the amounts provides effectively no basis for estimating the risk of these components of the flowback or produced water, and the RDSGEIS falls seriously short in this regard. A mere laundry list of these components does not meet requirements for analysis of their potential impacts. The list is so long, and the data on each component so incomplete, that it falls far short of the data that would normally be contained in a professional scientific risk analysis. Additionally, Tables 5.4 and 5.5 use trade names, and while the New York regulators may have information on the constituents in those products, that information was not available for this review. Additionally, the public does not have access to this information, and thus the public cannot legitimately understand or evaluate the risk of these products to their health or the environment that they live in.

   Table 6.1 reports the constituents found in flowback, and effectively none of the additive compounds used in fracturing were reported in the flowback, except for the hydrocarbons that occur naturally in the hydrocarbon formations (benzene, toluene, xylene, naphthalene, etc.). In fact, the only non-fuel compound found in flowback that is also mentioned as a hydraulic fracturing additive is propylene glycol. This analysis demonstrates a significant problem in examining flowback chemical composition. Either NYSDEC is concluding that chemicals injected into the formation do not return in the flowback (improbable), or NYSDEC has not employed the correct analytical methods to evaluate flowback waste constituents.

It is not clear from the RDSGEIS how many of the additives were actually subjected to analysis in the flowback samples. Most of the chemicals listed in Table 6.1 that are used as additives will not be detected/measured by the standard methods used to determine hydrocarbons and metals. Therefore, the absence chemical additives in the flowback samples shown in the RDSGEIS is likely a function of incomplete laboratory analysis. For example, it is not clear that any attempt was made to actually measure the following three compounds in the flowback water: (1) 1-propanesulfonic acid; (2) 2-propenoic acid, homopolymer, ammonium salt; (3) acetic acid, hydroxyl-, reaction products with triethanolamine. None of the methods used by the Marcellus Shale Coalition (see Chapter 5-109) would, in this reviewer's estimation, be suitable for measuring these compounds. In fact, many, if not most of the additives, require very specialized methods for analysis; some are multiple chemicals (e.g., polymers), and some are relatively unstable (e.g., acrylamide).

There is, however, an implication that since the compounds were not subject to analysis, and thus not observed in the flowback water, they do not exist in the flowback water, which is a scientifically unjustified conclusion and almost certainly not the case.

Table 6.1 should be re-created with an additional column that indicates whether the compounds would have been measured with the analytical scheme utilized (e.g., gc-ms, icp-ms, ion chromatography for anions, etc.). Additionally, the RDSGEIS should list the analytical method required to detect each compound in the flowback. The detection limit for each method should be specified.

A full analysis for all of the additives utilized in hydraulic fracturing is indeed a challenge, but the SGEIS should clearly indicate which compounds could be measured by the protocol utilized, which could not, and what method would be required. It is likely that most if not all of the additives used that are not found in the formation water were not actually measured/determined. Thus, Table 6.1 has very limited value, and provides a distorted view of what is actually being measured.

Recommendation 7. The analytical tables for hydraulic fracturing additives should be revised to clearly show the analytical methods utilized and whether the analytical methods used, and detection limits provided by those methods, are sufficient to protect human health and the environment. The tables should verify if the additives were actually measured in the flowback water.

Recommendation 8. The RDSGEIS should include as a mitigation measure a list of analytically testing methods required to test flowback prior to disposal; these testing requirements should also be codified in the NYCRR.

A detailed risk assessment of each of the potentially toxic additives is a reasonable request. Leakage of flowback water to domestic water has been demonstrated recently in Wyoming by the U.S. EPA (2011) and represents a potential threat to ground water in New York. It is not sufficient to simply argue that gas wells will not leak, since leaks are now apparent in certain well fields (e.g., most recently in Wyoming (US EPA, 2011a)), as well as in Pennsylvania (Pennsylvania DEC, 2011). When leaks occur, it is probable that the greatest risk will be from the naturally occurring substances, but the additives also pose a non-trivial risk.

Practically speaking, it is more efficient and cost-effective to limit the additives used, rather than test for every possible additive in the flowback. Other governments and agencies have developed simplified methods and lists for prohibiting toxic additives, and assessing their risk (e.g., OSPAR PLONOR, C-NLOPB Guidelines, The Norwegian Pollution Control Authority; see accompanying report of Susan Harvey regarding additives). NYS could develop a similar list of prohibited additives, and a process for approving additives for use that will offer a method for reducing risks to both the public and workers.

Some of the additives being used are serious carcinogens, and may be difficult to measure. Two examples of these are acrylamide and acrylonitrile. Both are carcinogenic and, while not long lived in the environment, can create serious exposure concerns to workers and the public.

Acrylonitrile has been found in Pennsylvania and/or West Virginia in water samples taken near hydraulic fracturing operations (data received from individuals who had samples analyzed). It was also observed in flowback water from the Marcellus Shale Coalition (page 5-115 of the RDSGEIS). Acrylonitrile is a carcinogenic (US EPA, 2011b) and exclusively anthropogenic compound. It can be measured in a standard purge and trap gc-ms method, and has been used in Pennsylvania, and is indicated in a patent issued to Halliburton (Halliburton Energy Services, U.S. Patent 7799744). This compound is one of the more toxic compounds used as additives, yet is not even mentioned in the RDSGEIS (Table 5.9). Failure to include a chemical additive that is commonly used and known to be carcinogenic and toxic to humans is a serious deficiency in the RDSGEIS.

Failure to include Acrylonitrile in Table 5.9 raises uncertainty in what other harmful chemical were not listed or examined in the RDSGEIS. Additionally, the RDGSEIS lacks of information on additives use rates. Therefore, the RDSGEIS analysis of the potential significant adverse impact of additive use is, at the least, incomplete.

Acrylonitrile, butadiene and styrene (ABS polymer) are mixed "on the fly" with the uncoated propping agent to create a polymer covering on the propping agent. From the Halliburton patent:

> Some suitable polymers include, but are not limited to, acrylic polymers such as acrylonitrile polymers, acrylonitrile copolymers, and mixtures thereof. Some preferred polymers include homopolymers and copolymers of polyacrylonitrile (including copolymers of acrylonitrile and methyl acrylate, methyl methacrylate, vinyl chloride, styrene and butadiene), polyacylates, polymethacrylates, poly(vinyl alcohol) and its derivatives, and mixtures thereof. As used herein the term "acrylic" polymers refers to any synthetic polymer composed of at least 85% by weight of acrylonitrile units (the Federal Trade Commission definition). Thus, the definition of the term may include homopolymers of polyacrylonitrile and copolymers containing polyacrylonitrile. Usually they are copolymers of acrylonitrile and one or more of the following: methyl acrylate, methyl methacrylate, vinyl chloride, styrene, butadiene. However, polymers that do not meet the definition of an acrylic polymer (such as those having less than 85% acrylonitrile) may also be suitable. For instance, Example 3 uses poly(acrylonitrile-co-butadiene-co-styrene) that contains approximately 25 wt % acrylonitrile.

Further down the patent, the "on-the-fly" process is described.

> In particular embodiments of the present invention, the particulates may be coated with the polymer solution and introduced into the treatment fluid, which acts as the aqueous medium, directly prior to being introduced into a subterranean formation in an on-the-fly treatment.

This process is likely to be inefficient and likely to release substantial amounts of acrylonitrile and styrene into the water used in the fracturing process. Acrylonitrile has been found in flowback water (page 5-115 of the RDSGEIS), and reports are available that show that it has been detected in surface and ground water in Pennsylvania, and is perhaps one of the most unambiguous anthropogenic indicators that off-site contaminated water has been in communication with the water used in the fracturing process. NYSDEC should determine if this polymer and application method is appropriate for use in New York, and require acrylonitrile and styrene as two of the suite of compounds to be analyzed in flowback before it leaves the wellsite.

Recommendation 8. The NYSDEC should re-examine the additives used in hydraulic fracturing and conduct a much more detailed analysis of the risk of these compounds. Specifically , acrylamide and acrylonitrile, a carcinogenic and exclusively anthropogenic compound used in hydraulic fracturing, should be measured in flowback water, and an assessment made as to whether and/or how use of this compound should be permitted. The conclusions of such analysis should be included in the SGEIS as a mitigation measure and codified in the NYCRR.

B. The analytical data presented in Tables 5.10, 5.23, 5.24 and 6.1 all indicate a lack of detailed understanding of the quality of the flowback, and indicate

an inadequate understanding of the methods necessary to fully characterize the wastewater.

The errors in Tables 5.10, 5.23, 5.24 and 6.1 are sufficiently glaring that they need a much more detailed review. For example, in Table 5.10, the dissolved metal concentrations in some cases are higher than total metals. Iron, for example, has a median concentration 29.2 mg/L, but the dissolved median concentration is 63.25 mg/L. Similarly, the mean manganese concentration is 1.89 mg/L, while the dissolved manganese concentration is 2.975 mg/L. There cannot be higher amounts of dissolved iron and manganese than total iron and manganese.

The data from the Marcellus Shale Coalition was not displayed, other than as a table of compound detections. These samples were collected from 19 gas well sites in Pennsylvania and West Virginia. All samples were collected by a single contractor and the analyses performed by a single laboratory, which should reduce the variability. This would appear to be a very valuable data set, but surprisingly, no data were presented regarding concentrations of the analytes. Some comments were provided on the types of compounds detected, although it was not clear which types of water contained these constituents. Additionally, chlorinated hydrocarbon insecticides were detected, which is very surprising, since these compounds could not have been found in the formation water, and have not been used in the U.S. since the 1970's. They are likely false positives, although it is not possible to make that determination, based on the discussion in the RDSGEIS. Data obtained from the Marcellus Shale Coalition should be presented, which compares, for example, flowback water from different wells under similar conditions (e.g., immediate flowback versus flowback in subsequent days).

Finally, the data in Table 6.1, which focuses on the additives used in hydraulic fracturing, is problematic. As discussed above, it is highly unlikely that attempts to determine the concentrations of the fracturing additives were actually conducted, since many of these compounds are difficult to determine. The implication remains, however from Table 6.1, that these compounds were actually considered in some appropriate analytical scheme. This is almost certainly not the case, and Table 6.1 should be clarified.

Recommendation 9. Each of the SGEIS tables of analytical data should be reviewed by an analytical chemist, and the data be presented in a scientifically accurate and quality controlled manner. The data in Table 6.1 should be clarified and the compounds which were not subjected to specific analyses should be identified.

C. Permissible treatment of the flowback and the produced water is not well defined. It is unclear how the post-treatment residual salts and radioactivity will be managed. There does not appear to be any complete treatment of these waters that will be permitted in New York.

There are four possible treatment options for flowback and produced water discussed in the RDSGEIS: (1) reuse, (2) deep well injection, (3) treatment in municipal facilities, or (4) treatment in privately owned facilities. None of these options is properly analyzed in the RDSGEIS, and the potential significant adverse impacts of each are therefore not disclosed nor possible mitigation identified.

"Treatment" of flowback for *reuse* is discussed in Section 5.12. Reuse of the flowback conserves fresh water and allows contaminated water to be used instead during fracturing. However, the RDSGEIS only considered treatments for removal of salts that would allow for reuse in other hydraulic fracturing operations, and evaluated how specific requirements for reuse could be met by various treatment processes (e.g., membrane, ion exchange or evaporative processes). It did not analyze the residual contaminants removed by evaporative or membrane processes and thus concentrated, or how those contaminants would be managed, other than to indicate that the residual salts, or concentrated brine will require "further treatment or disposal." The SGEIS must address how this highly concentrated and toxic residue will be regulated and managed.

Three hundred tons of salt will exist in one million gallons of flowback or produced water brine, if you assume a 7% (70,000 mg/L) salt solution. The source of the alpha emitters also must be identified, as is discussed above. If, as is suspected, polonium is present in the flowback water, it represents an additional management burden of the flowback and produced water that must be evaluated.

Beyond reuse, the disposal options considered in the RDSGEIS only included injection wells (although there are currently no industrial waste injection wells capable of handling this wastewater in NYS), municipal sewage treatment facilities (of which there are currently none that are permitted to accept flowback and produced water), and private treatment plants (of which none currently exist in New York). Therefore the RDSGEIS examines options that do not exist, and does an incomplete job of that examination.

The RDSGEIS did not consider whether there are other, less environmentally harmful, options that exist for treatment and disposal of flowback and produced water. More importantly, the RDSGEIS fails to evaluate the potentially significant adverse environmental impacts and human health risks associated with each treatment and disposal option.

Section 6.1.8.1 indicates that "[f]lowback water may be sent to POTW's", but then describes the limitations that may preclude disposal of these waters in POTWs. The RDSGEIS requires that a "facility must first evaluate the pollutants present in that source of wastewater against an analysis of the capabilities of the individual treatment units and the treatment system as a whole to treat these pollutants" (page 6-57); however, before such an evaluation can be conducted, the well operator must obtain a complete analysis of the flowback water (which as explained above, has not been done).

Additionally, the diversity of the flowback water quality is such that a POTW would need to conduct an extensive and expensive analysis of each water type that was delivered to the POTW under those guidelines. Since most of the additives are clearly not subject to routine analyses, it appears doubtful that a POTW could ever accept this type of waste. Also, if the limitation of 15 pCi/L of radium in the influent is enforced, a large portion (as yet not determined) of the flowback water could not even be accepted. Finally, the requirement of a complete description of the contaminants in the water is likely to add an additional burden to using POTW's for disposal, that this option may be precluded for most of the flowback water. Therefore, the proposal to use POTWs as a potential treatment and disposal method is scientifically and technically unsupported.

One serious problem with the proposed discharge (dilution) of fracture treatment wastewater via a municipal or privately owned treatment plant is the observed increases in trihalomethane (THM) concentrations in drinking water reported in the public media (Frazier and Murray, 2011), due to the presence of increased bromide concentrations. Bromide is more reactive than chloride in formation of trihalomethanes, and even though bromide concentrations are generally lower than chloride concentrations, the increased reactivity of bromide generates increased amounts of bromodichloromethane and dibromochloromethane (Chowdhury, et al., 2010). Continued violations of an 80microgram/L THM standard may ultimately require a drinking water treatment plant to convert from a standard and cost effective chlorination disinfection treatment to a more expensive chloramines process for water treatment. Although there are many factors affecting THM production in aspecific water, simple (and cheap) dilution of fracture treatment water in a stream can result in a more expensive treatment for disinfection of drinking water. This transfer of costs to the public should not be permitted.

NORM, the inorganic substances, and the organic compounds from the formation also represent serious contamination potential and require an appropriate level of treatment. The exact method of treatment that NYSDEC expects to require for any municipal or private treatment facilities that may be permitted is unclear. The RDSGEIS suggests that there will be some level of wastewater dilution through discharge into a receiving stream, at least in some cases. The analysis should be much more explicit about how wastewaters will be treated, both in-state and out-of-state. New drilling operations should not be permitted until adequate management/disposal of these waters is evaluated, with public comment required on the proposed methods, an analysis of the impacts associated with each, as well as mitigation measures as required by SEQRA.

Injection of the waste fluids into fully permitted underground injection control (UIC) wells is an option also, although this method is problematic due to the lack of permitted wells in New York, and the distance the contaminated water would need to be trucked in order to dispose of it in other states where permitted wells exist (e.g., Ohio). The recent seismic activity in Ohio from disposal of fracturing fluids also raises serious concerns whether this option is safe. Given the difficulties of wastewater treatment, UIC is likely the popular choice for wastewater disposal from the Marcellus region. However, NYS' increase wastewater load, along with increased wastewater generated from the increased drilling in Ohio and surrounding states, will likely pose an injection capacity problem for Ohio UIC wells. The RDSGEIS has not examined whether it is possible, or safe to install disposal wells in NYS' or whether a nearby state has sufficient capacity to inject NYS' incremental waste load, or whether this is the best technical solution. These are all potential significant adverse impacts that should be, but are not, addressed in the RDSGEIS.

Out-of-state management of waste is contemplated in Section 5.13.3.3., but is identified as not being within the regulatory purview of New York. However, simply stating that wastewater will likely be managed "out-of-state" is insufficient. Wastewater handling is an unmitigated significant impact in the RDSGEIS as currently proposed. The proposal to export NYS' wastewater and not examine this significant impact is not justified.

NYSDEC should instead evaluate the impacts of, clear cradle-to-grave oversight and management, identify the best solutions for waste handling, and include those requirements as mitigation measures in the RDSGEIS.

Furthermore, even if some export of wastewater is permitted, SEQRA requires analysis of the impacts of any potential waste management options, even if they are to occur outside of New York.

Finally, road spreading for dust control and de-icing would apparently (and appropriately) not be allowed for flowback water, but could be used under certain conditions for the produced brines. A rationale for this distinction is not provided, and permitting road spreading of produced water is not recommended, since the brines will have higher concentrations of NORM than the flowback water, and may include polonium. Some rationale should be provided for this distinction, particularly since it is apparently unknown if any of the hydraulic fracturing additives are even detected in the flowback water (see Table 6.1). It is clear, however, that the NYSDEC is concerned about using the brines for roads and will require a specific permit for this application. Whether a permit will be granted presumably will depend on the amount of radioactivity present in the water. Under no circumstances should brine solution that has a gross alpha concentration of greater than 15 pCi/L be applied to roads. Ultimately, this practice should not be allowed – there are simply too many questions about the identity and amount of contaminants in these fluids.

Recommendation 10: The RDSGEIS should identify and evaluate the impacts of the various options that are proposed to be permitted for management of wastewater, and identify any proposed mitigation for identified significant adverse impacts, which should be set forth in the proposed regulations.

Recommendation 11. Specific influent contaminant load restrictions need to be explicitly identified including those for: fracking additives, NORM (including gross alpha), TDS and other relevant contaminants in this management description.

D. Cuttings disposal: Disposal of cuttings is considered in the RDSGEIS, although the treatment is incomplete. Cuttings from the shales of marine origin such as the Marcellus Shale (particularly the horizontal cuttings) will require further examination to determine if they contain large amounts of salts, similar to the produced brines, or if they contain excessive alpha emitters. While the measurements of radioactivity, based on a gamma detector, do not indicate high levels of radioactivity, further analysis is required to determine the leachability of these cuttings. Polonium is only a very weak gamma emitter, and thus it would not be observed by simple gamma counting. The organic (reducing) components of the shales chemically trap uranium and potentially other radionuclides, and when they are subject to oxidizing conditions, increases in the solubility/mobility of some of the radionuclides (particularly uranium) is likely. The leachability of these cuttings under oxidizing conditions thus requires further analysis, as discussed at the bottom of page 6-65. However, these determinations need to be made, and the risks and potential mitigation identified, *prior* to permitting the wells.

Recommendation 12. The RDSGEIS must fully evaluate the potential significant adverse impacts of cuttings disposal and identify any necessary mitigation to address such impacts, which should be set forth in the proposed regulations.

E. Odors are a continuing concern from gas wells: A variety of chemicals are present in hydrocarbon formations that can present a serious odor problem, which can be both a serious human health problem and affect the quality of life of persons living near these sites. A very common, but toxic, constituent is hydrogen sulfide, characterized by a rotten egg smell. Other organic sulfides can also be present, including a variety of alkyl sulfides. Odors are very difficult to regulate, due to the vagaries associated with odor detection, acclimation, and differential effects on different persons. The severity of an odor is in the nose of the beholder. Thus, each well should be assessed to determine the potential of migration of volatile substances from the well operation to surrounding residents. Odor complaints should be taken seriously, and the presumption should be that an odor complaint is valid, and an investigation of the source required.

Hydrogen sulfide is, however, probably the most acutely toxic component present in a potential natural gas leak, and it can pose a serious health risk to surrounding residents, in addition to causing odor complaints. Sulfide monitors should be required at least two points, corresponding to most probable downwind locations at the fenceline. When hydrogen sulfide is detected above the odor thresholds, the source of the odor should be identified and eliminated.

Setbacks from an operating well will help to minimize the impact of odors on the surrounding residents. (Setbacks are discussed in further detail in the accompanying reports being submitted under cover of the Louis Berger Group.)

Recommendation 13. The RDSGEIS must fully evaluate the potential significant adverse impacts associated with odors and hydrogen sulfide emissions, and identify any necessary mitigation to address such impacts, which should be set forth in the proposed regulations.

F. Monitoring of nearby domestic wells for contamination from gas drilling operations should be conducted at regular intervals during and following hydraulic fracturing. While the drilling company would be required to test domestic wells for contamination prior to gas development operations, these same wells should be tested during production, and subsequent to discontinuing production to determine if hydraulic fracturing has resulted in contamination (See the accompanying report of Dr. Tom Myers). At present, the documents are silent on this requirement and effectively transfer this responsibility to the well owner. The analytes that should be determined should include, at a minimum, the components of natural gas (methane, ethane, etc.) and also toxic volatiles from the formation water (benzene, toluene, xylenes), salts and relevant inorganic contaminants, and the additives used during the hydraulic fracturing. This list should be developed based on those specific additives used.

Recommendation 14. The RDSGEIS and proposed regulations should require that monitoring of domestic wells situated in close proximity to gas drilling operations to be required at regular intervals during and following hydraulic fracturing. Because of the slow movement of groundwater, routine analysis of those domestic wells should be continued at least 20 years.

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Attachment 4

Ralph Seiler, Ph.D.

Review of the

Revised Draft
Supplemental Generic Environmental Impact Statement On The Oil, Gas and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

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1/11/12

This document represents a review of the Revised Draft Supplementary Generic Environmental Impact Statement (RDSGEIS) regarding the hydraulic fracturing proposals to develop natural gas wells in New York. I have specifically examined issues related to NORM in the flowback/produced brine, as well as of radon in the gas itself. My comments supplement those of Glenn C. Miller, Ph.D.

Issue 1.

<u>Unidentified sources of gross alpha and beta radioactivity in flowback water and production brine.</u>

Gross alpha radioactivity in the brines (Appendix 13) and flowback water (Table 5-24) can be very high. In the brines, gross alpha is usually from 8,000 to 20,000 pCi/L, with a maximum of 120,000 pCi/L (Well Webster T1). In the brine samples with high gross alpha, the sum of uranium (U) , thorium (Th) , radium-226 (^{226}Ra) and radium-228 (^{228}Ra activities is much less than the measured gross alpha. Individual analyses of flowback water are not given, but the aggregated data similarly suggest that the sum of U, Th, and ^{226}Ra and ^{228}Ra activities is also much less than the measured gross alpha. These results indicate one of two things:

1. There are analytical problems with the gross alpha measurements, probably caused by the high salinity of the water.
2. There is an unidentified alpha emitter present in the water.

High salinity can cause the measured gross alpha to significantly overestimate the actual alpha activity of a sample (Arndt and West, 2007). The recommended mass placed on a planchet for gross alpha is only100 mg, so given a brine Total Dissolved Solids (TDS) of 350,000 mg/L (p. 6-61), only ~0.4 ml of sample should be placed on a planchet. The high TDS means it is easy for too much mass to be placed on the planchet, or the small volume means the mass may be unevenly distributed. Both of these factors can contribute to reduced precision and accuracy in the gross alpha analysis.

Appendix 13 indicates all of the relatively long-lived, naturally occurring alpha emitters in the brines were measured except polonium-210 (^{210}Po). Radon itself would not contribute at all to the measured gross alpha because it is a gas. In the gross alpha measurement, an aliquot of sample water is placed in a planchet and evaporated to dryness. After drying, the planchet is commonly flamed until it glows red to drive off hygroscopic water from the salts. Because of this, alpha radioactivity from radon does not contribute to gross alpha radioactivity.

^{210}Po normally binds strongly to sediment particles and concentrations in fresh groundwater are typically <1 pCi/L. In some geochemical settings ^{210}Po activities have exceeded 500 pCi/L in drinking-water wells in the US (Seiler et al., 2011), however this is extremely rare and fewer than 100 US wells have been reported with >15 pCi/L. ^{210}Po is known to be present in oil-field brines (Parfenov, 1974), however, the reported ^{210}Po activities in the brines were relatively low, about 100 pCi/L.

On p. 6-205 the RDSGEIS states radium is the primary radionuclide of concern, but this may not be the case if the excess alpha radioactivity is caused by the presence of ^{210}Po. If ^{210}Po is present in high levels, it may be much harder and more expensive to treat the contaminated water and manage the waste. Ra can be removed from water with relatively simple technology such as water softeners. On the other hand, Charles County in Maryland found the best way to remove Po from a contaminated public-supply well was with reverse osmosis. Treating millions of gallons of brine with reverse osmosis would be expensive and difficult, and could increase the cost to the public if treated at a public treatment facility. It could cause the gas to be more expensive to the consumer if the operator is made to bear the cost of treatment at an on-site or privately-owned treatment facility.

Gross beta radioactivity in many of the wells in some of the wells is several thousand pCi/L. To evaluate the significance of this, you need to know the potassium concentrations because ^{40}K is the source of almost all natural beta. If gross beta minus a correction factor for K were to exceed 50 pCi/L in a municipal well, the operator would have to identify the major contributors to gross beta. One potential contributor to gross beta is lead-210 (^{210}Pb), which was not measured. This is potentially important because ^{210}Pb decays to ^{210}Po and could support it in the water.

Issue 1 Recommendations

The cause of the excess alpha radioactivity in the brine and flowback samples needs to be determined. ^{210}Po may be present at high concentrations and could pose a significant risk to health and the environment if oil-field brines are inadequately disposed of because it bioaccumulates. Samples from some of the more contaminated wells should be reanalyzed for the same suite of analytes as before, except this time include ^{210}Po. Redoing the complete suite will provide an idea on how adequately the less expensive gross alpha analysis identifies the presence of ^{210}Po. All samples analyzed for NORM (e.g. p. 6-61) as part of the regulatory process should include ^{210}Po, at least until it has been demonstrated that ^{210}Po is not an important source of alpha radioactivity.

NYSDEC should identify what the important contributors to gross alpha are (probably radium and ^{210}Po) and identify how, if at all, the brine and flowback water will be treated, taking economic considerations into account. Failure to do so constitutes a potentially significant adverse impact that would not have been disclosed or mitigated.

The principal contributer to the gross beta radioactivity is probably potassium-40 (^{40}K), but this should be confirmed because ^{210}Pb can also contribute to gross beta, and if present ^{210}Pb can support aqueous ^{210}Po. An estimated ^{40}K activity, based on the potassium (K) concentrations for the brines, should be added to Appendix 13 so the gross beta measurements can be evaluated. It is presumed that K was measured, even though no major ion analyses for the brines were found in the RDSGEIS. A theoretical activity ratio of 0.818 pCi/mg was reported by Friedlander et al. (1981) and can be used to convert concentrations to activities.

Issue 2.

Documentation of analytical methods

It is important that all analytical methods that will be used to analyze pollutant levels are well documented, but the RDSGEIS does not indicate what they would be.

Issue 2 Recommendations

It is presumed the alpha emitters were analyzed by alpha spectrometry, but the RDSGEIS should confirm this. The RDSGEIS also needs to provide reporting limits for the other analytes, not just provide a list of the analytes to be measured. An analysis for arsenic is useless if the reporting limit is 50 ppb when the drinking water standard is 10 ppb.

Documentation of the method is particularly important for the gross alpha analysis. EPA Method 900.0 for gross alpha allows samples to be composited quarterly and allowed to sit for up to a year before analysis. Unfortunately, the EPA approved analytical method can allow more than 60% of the ^{210}Po in a sample to be lost due to decay during that year (Seiler et al., 2011). A simple statement that Method 900.0 will be followed is inadequate. The RDSGEIS should explicitly state that samples for gross alpha will not be composited and must be analyzed within 3 days of sample collection. Analysis within 3 days is SOP for many agencies and finding labs that can meet that requirement should not be a problem.

Issue 3.

Radon in Natural Gas

Radon is known to be present in natural gas and will be delivered with the natural gas to consumers. Burning of natural gas in stoves, water heaters, and furnaces does not affect the radioactivity of radon and consumers will be potentially exposed to increased levels of atmospheric radon.

The RDSGEIS does not include measurements of radon concentrations in the natural gas, nor does it indicate plans to monitor it. Radon concentrations in natural gas are extremely variable and can be very high. Natural gas from Texas and Kansas had radon concentrations ranging between about 5 and 1500 pCi/L (Dixon 2001,

Table 2). This raises the possibility that radon concentrations in gas from the Marcellus Shale could be much higher values than are in the gas currently being used. In addition, the hydraulic fracturing process would be designed to maximize extraction of natural gas from the formation, and as a consequence may also maximize extraction of radon from the formation.

The pipeline from well heads tapping the Marcellus Shale will be much shorter than the existing 1500 mile pipeline delivering gas from Texas/Louisiana. Assuming the gas moves through the pipeline at 10 mph, it would take 6.25 days for gas from the wellhead to the consumer, and during this time ~68 percent of the radon will decay. If wellheads in the Marcellus Shale are only 100 miles from the consumer then only 7 percent of the radon would have decayed. Because of this, even if the wellhead radon concentrations in gas from the Marcellus Shale were identical to those of the currently used natural gas, consumers would be exposed to greater radon concentrations because the wellheads are closer.

Dixon (2001) provided a risk assessment for the radon in natural gas in the UK. The average radon in natural gas from the UK wells was 5.4 pCi/L, and, as a worst-case scenario, Dixon (2001) assumed that there was instantaneous delivery of the gas so that no radon decay occurred between the wellhead and the consumer. Dixon (2001) concluded there was negligible risk to the public from release of radon in combustion gasses, and that the average dose to the public using 100 cubic meters of gas would be only 4 microSieverts per year (μSv/yr). The greatest risk was to workers in large commercial kitchens who would receive a dose of 19 μSv/yr.

Issue 3 Recommendations

The risk to the public from radon in the natural gas probably is small. Measurements of radon in the gas are needed, however, to confirm that radon levels in the gas are within the expected range. A new risk assessment should be made using actual measurements of radon in gas from the Marcellus Shale and other factors specific to New York, such as the background radon concentration for the area. For a worst-case scenario the assumption should be made that there is instantaneous delivery of gas from the wellhead to the consumer.

Issue 4.

<u>^{210}Po Buildup in Delivery Pipes</u>

On page 6-205 of the RDSGEIS there is a discussion of scale buildup in pipes and equipment, but the discussion seems to indicate Ra is the principle radionuclide of concern. If radon, ^{210}Pb or ^{210}Po are present at high concentrations in the water or gas, a more significant health risk for workers could be ^{210}Po in the scale. Summerlin and Prichard (1985) evaluated this and concluded that workers cleaning impellers could be exposed to high levels of atmospheric ^{210}Po.

Consumers and State and Local workers may also be exposed to ^{210}Po, which will form in scale on all pipes carrying natural gas with radon in it. The amount of ^{210}Po buildup will depend on the amount of radon in the gas. Plumbers and City/State employees working on the pipes may not know what precautions need to be taken, and thus could be exposed to ^{210}Po in the scale.

Another issue is the volatility of ^{210}Po, which is completely volatile at temperatures above 500^{o}C (Radford and Hunt, 1964). Because of this, ^{210}Po that accumulates near burners that have been turned off may be vaporized when burners are turned on. This could potentially expose consumers to health risks from inhaling ^{210}Po. In cases of accidents or fires involving gas lines, first responders and the public near the incident could also be exposed to ^{210}Po through inhalation. This risk is not specific to gas from the Marcellus Shale. The health risks, however, would be related to the amount of radon in the gas and thus the amount of ^{210}Po that would build up, and this is not known for gas from the Marcellus Shale.

<u>Issue 4 Recommendations</u>

Measurements of radon in natural gas from the Marcellus Shale need to be made. A risk assessment should be made for inhalation of ^{210}Po resulting from scale buildup in delivery pipes.

Issue 5.

^{210}Po drinking-water standards

Table 2-3 presents drinking water standards for radionuclides. The US does not have a standard specifically for ^{210}Po largely because ^{210}Po is extraordinarily rare in drinking water. The US standard for ^{210}Po is exceeded if the gross alpha minus the U activity exceeds 15 pCi/L. Canada and the European Union have set drinking-water standards specific for ^{210}Po at 5.4 and 2.7 pCi/L, respectively (Health Canada, 2007; Commission of the European Communities, 2001). The regulatory use of the gross alpha standard assumes it will adequately identify samples with ^{210}Po levels that exceed health safety standards. For several reasons related to Po chemistry and the gross alpha analytical method, this may not be the case (e.g. Seiler, 2011).

Item 5 Recommendations

For any analysis where there may be actual human exposure, the RSDGEIS should analyze ^{210}Po analyses using alpha spectrometry rather than using gross-alpha analyses as an inexpensive but inadequate surrogate.

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Attachment 5

Susan Christopherson, Ph.D.

Memorandum

To: Kate Sinding, Natural Resources Defense Council

From: Susan Christopherson, Ph.D.

Date: January 11, 2012

This memorandum comments on issues in the sections of the 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) and accompanying documents that address the social and economic impacts of natural gas development using high volume hydraulic fracturing (HVHF) proposed for New York, and evaluates the sufficiency of the impact analysis presented and the mitigation measures identified. HVHF describes a stage in the gas extraction process whereby large amounts of water, toxic chemicals, and sand are injected at high pressure to create fissures in low-permeability formations and thereby allow the release of gas. The process is capital intensive, and throughout its duration, poses significant environmental risks. The New York State Department of Environmental Conservation (NYSDEC or the Department) is charged with identifying and evaluating the impacts of gas development using HVHF, including both the benefits and the costs that will be borne by the communities and counties where drilling will occur.

In preparing these comments, the key documents reviewed include:

- The 2009 scope of work for the SGEIS.
- Comments prepared by AKRF and other technical experts on the 2009 draft SGEIS.
- A report prepared by Sammons, Dutton and Blankenship (2010) in response to comments on the 2009 draft SGEIS analysis of socio-economic impacts.
- The RDSGEIS released in September 2011 and particularly sections addressing socioeconomic and community impacts (6.8 and 6.12) and mitigation (7.0).
- The Economic Assessment Report (EAR) prepared by Environment and Ecology LLC to accompany the RDSGEIS.

These comments also draw on my own research on input/output models and community impacts and on research that has been conducted on the social and economic impacts of natural gas drilling in shale gas plays across the United States. Other documents cited in these comments are included in the reference list.

Although NYSDEC has included more information on the social and economic impacts of gas development using HVHF in the RDSGEIS than it did in the 2009 draft, the RDSGEIS still does not effectively assess those impacts or provide appropriate mitigation strategies. These comments identify areas of social and economic impact that require additional or revised research or analysis in the SGEIS. Overall, the discussion of social and economic impacts in the RDSGEIS is poorly organized. Social and economic topics are discussed in several sections of the RDSGEIS and statements are made in some sections that are contradicted by evidence in others. The differences between the social and economic impacts of vertical and horizontal drilling are not addressed in a systematic way. Critical assumptions underlying the socioeconomic impact analysis were accepted from industry sources (the Independent Oil and Gas Association of New York or IOGA NY) without independent verification.

Substantive concerns include the following:

1. The assessment of economic benefits (jobs and taxes) relies on questionable assumptions about the amount of gas extractable in the New York portion of the Marcellus Shale. The range of estimates for extractable gas appears to be skewed to the high end, leading to an overestimation of economic benefits.

2. The model used to assess social and economic impacts presents natural gas development as a gradual, predictable process beginning with a “ramp-up” period and then proceeding through a regular pattern of well development over time. Experience from shale plays in the Western United States demonstrates that volatility and unpredictability are intrinsic to natural gas extraction, as operating companies assess their commercial options from one shale play to another or within one shale play and allocate rigs to respond to those options. The model used in the RDSGEIS is misleading, giving the impression that communities in the drilling regions will experience economic disruption only once, during a ramp-up phase, rather than periodically, as operating companies repeatedly enter and leave the region. The problems with the model are then compounded, as projected impacts on population, jobs, and housing are predicated on one-time ramp-up and adjustment phases rather than on a process in which rigs may move in, move out, and move in again, in an unpredictable sequence. Because many of the negative social and economic impacts of HVHF gas extraction (such as housing shortages followed by excess supply) are a consequence of unpredictable development, the model used in the RDSGEIS cannot appropriately assess those impacts. The limitations of the model should have been explained with reference to the literature that describes the irregular, unpredictable course of natural gas development, including rig movement among shale plays and the frequency of re-fracturing wells.

3. The RDSGEIS does not assess public costs associated with natural gas development. A fiscal impact analysis of the base costs to the state and localities that will occur with any amount of HVHF gas development is required along with an estimate of how costs will increase and accumulate as development expands. Although some of the potential community character and economic costs associated with the projected drilling scenarios are mentioned in the RDSGEIS, there is no attempt to quantify those costs to the state or localities either as part of the modeling process or separately.

4. The long-term economic consequences of HVHF gas development for the regions where production occurs are not addressed despite a widely recognized literature indicating that such regions have poor economic outcomes when resource extraction ends.

5. Mitigation of enumerated negative social and economic impacts of HVHF gas development is presumed to occur by means of phased development and regulation of the industry, but no evidence or information is provided to indicate whether, and if so how, that would occur. For example, NYSDEC proposes to ask operators to identify inconsistencies with local zoning and other comprehensive land use planning, but there is no explanation of how the inconsistencies will be addressed in the permitting process or regulatory system. All mechanisms that will be relied on to address adverse social

and economic impacts need to be defined and incorporated into enforceable mitigation measures.

Part I of these comments focuses on the socioeconomic impact analysis in section 6.8 of the RDSGEIS. Section 6.8 adopts the assumptions utilized in the EAR and summarizes its more detailed description of anticipated impacts from HVHF gas development. Part I.A pays particular attention to the model employed in the EAR and its assumptions about how the exploratory, drilling, production, and resource depletion phases of development will occur. These assumptions do not adequately consider the uncertainties and risks associated with HVHF gas development. Part I.B comments on particular issues and areas of impact addressed in the RDSGEIS. Part II discusses issues pertaining to the distribution of economic benefits that are raised by the EAR but not addressed in the RDSGEIS. Part III comments on the mitigation proposed for potentially significant social and economic impacts.

I. NYSDEC's Socioeconomic Impact Analysis

A. The Unpredictability of Natural Gas Production and How It Is Treated in the RDSGEIS

The EAR's projections concerning population, jobs, housing, and revenue are predicated on the assumption of a regular, predictable roll-out of the exploratory, drilling, and production phases of the natural gas development process, rather than the irregular pattern typically associated with such development.

Natural gas drilling is a speculative venture and the amount of commercially extractable gas from any particular well is uncertain. Because of the speculative nature of the industry, there are significant economic risks associated with natural gas production. These risks are magnified by the costs involved in natural gas development, which uses capital-intensive technologies such as those engaged in hydraulic fracturing.

The industry is organized in such a way that these risks can be lessened. For example, a limited number of rigs is available nationally, and they are deployed among and within natural gas plays based on calculations of well productivity and commercial return. The drilling labor force is not fixed to a place, but moves with the rigs based on operator company strategies. Work is carried out by contractors on a project-by-project basis to maximize flexibility and efficient deployment of the specialized skills needed.

Because of the speculative character of commercial development of natural gas plays, there are uncertainties in how any shale gas play or portion of a play will be developed. What this means in practical terms is that the regions where shale gas development occurs can experience considerable volatility in the timing of well development and in the scale of well development (in the total number of wells). This central feature of natural gas development has critical implications for the economies of natural gas development regions. As production fluctuates, regions may experience short- and medium-term volatility in population, jobs, revenues, and housing vacancies (Best, 2009; Headwaters Economics, 2011; Jacquet, 2009; Sammons, Dutton and Blankenship, 2010).

The EAR does recognize both production volatility and price volatility in the gas industry. In describing national drilling activity, the authors report: "The number of active gas drilling rigs fluctuated substantially over the decade, with the number of rigs in the most active quarter being 2.35 times the number in the least active quarter." (EAR, 2-2). In New York, "the average wellhead price for natural gas remained at relatively low levels in the 1990s, generally increased thereafter, reaching a peak in 2008, and then fell sharply in 2009." (EAR, 3-12).

The EAR also briefly mentions the difficulties that the unpredictability and volatility of natural gas development presents for predicting social and economic impacts (e.g., EAR, 4-59, 4-111). The model used to project socioeconomic impacts ignores those issues, however, and assumes instead that the HVHF natural gas development in New York will have a different pattern than that historically associated with such development. Rather than occurring in irregularly recurring waves (or "boom-bust cycles"), development in New York is assumed to be steady and predictable.

The RDSGEIS mentions the uncertainty and variation in well productivity in sections not addressing socioeconomic impacts (RDSGEIS, 2-5, 2-62, 2-74, 4-17). However, the section of the RDSGEIS that specifically addresses socioeconomic impacts (Section 6.8) ignores the evidence of unpredictability in the pace and scale (timing and total well development) of natural gas development from New York counties with vertical well development and from other shale plays. Instead, it reports results from the model used in the EAR to project social and economic impacts from HVHF gas development that assume a regular, incremental, and predictable pattern of well development and production over a 60-year period, both on a statewide basis in three defined regions and under two development scenarios (low and average). Like the EAR, the RDSGEIS neglects the implications of variable well productivity and commercial viability -- critical considerations that will affect the pace and scale of drilling as well as its geographic distribution.

A1. Uncertainties Regarding Well Productivity

The RDSGEIS and accompanying EAR do not meaningfully recognize a central category of uncertainties that will affect the pace and scale of drilling – the uncertainties surrounding well productivity. Instead, NYSDEC states with respect to the low and average development scenarios analyzed:

> Both development scenarios assume a consistent timeline for development and production. Development is assumed to occur for a period of 30 years, starting with a 10-year ramp-up period. The number of new wells constructed each year is assumed to reach the maximum in Year 10 and to continue at this level until Year 30, when all new well construction is assumed to end.

(RDSGEIS, 6-209).

This approach is one of the major weaknesses of the RDSGEIS because the assumptions of a 30-year well production cycle and a sub-regionally consistent roll-out of wells that will move through the drilling and production phases over 60 years are not supported by evidence from other shale plays. In fact, there is sufficient evidence of precipitous declines in well productivity and the costs of HVHF gas development relative to ultimate recovery to raise questions about why the 30-year development/60-year productivity profile was adopted (Berman, 2010; Berman and Pittinger, 2011; Hughes, 2011; Urbina, 2011). In an analysis of shale gas wells across shale plays, Berman and Pittinger (2011) found thousands of wells that dropped below commercially viable production between 5 and 12 years after initial drilling. The average commercial life of these wells was 8 years. NYSDEC should not have used data provided only by IOGA to construct the roll-out model; rather, it should have obtained evidence and data from independent sources who do not stand to benefit from the projection of long-term, predictable resource development.

<u>Another example of questionable assumptions that likely over-estimate potential gas extraction from the New York portion of the Marcellus Shale is the well productivity projections used in the EAR.</u> These are presented in Tables 4-3, 4-4 and 4-5 of the EAR. Although ultimate recovery figures are not presented in the EAR, they can be calculated based on the yearly production projections presented in 4.1.3 and the number of wells projected in 4.1.2.

These productivity projections are considerably higher than the well productivity results from existing shale plays found by Berman and Pittinger (2011). In addition, calculations of well productivity over the 60 year period produce ultimate recovery figures for the New York portion of the shale play that, in the medium and high scenarios, exceed most scientific estimates of ultimate recovery (Coleman et al, 2011). Although the 29 Tcf <u>low</u> scenario (for 60 years) does not exceed geologist Terry Engelder's estimate for New York's portion of the Marcellus shale, the productivity projections seem particularly questionable considering that, "The Marcellus fairway in New York is expected to have less formation thickness, and because there has not been horizontal Marcellus drilling to date in New York the reservoir characteristics and production performance are unknown. IOGA-NY expects lower average production rates in New York than in Pennsylvania." (RDSGEIS, 5-139).

Moreover, as pointed out by a group of economists commenting on the EAR assumptions and methods (Barth, Kokkelenberg and Mount, 2011), the range of estimates of productivity is so large as to be meaningless. For example, estimates for well productivity during the 23rd year of production range from 600 billion to 3.6 trillion cubic feet, a variation on the order of 600%. Accuracy in these estimates is critical to derive estimates of tax and employment effects. As it stands, the estimates used in the EAR are no better than bloated "guesstimates."

The use of IOGA's estimates as the sole source of well productivity projections undermines the credibility and accuracy of the EAR and the RDSGEIS. The estimates of well productivity must be revised to more accurately reflect expert opinion on anticipated well productivity in the New York portion of the Marcellus shale. In addition, the RDSGEIS must be updated to reflect the Energy Information Administration's revised estimates of natural gas in the Marcellus shale based on the USGS analysis (Coleman et al, 2011).

<u>The uncertainties associated with the productivity of extraction from the Utica shale must also be addressed, if Utica shale wells are to be included in the SGEIS analysis.</u> In the EAR, the projections for the number of wells to be drilled include those for the Utica shale. There are significant uncertainties about the productivity of that play, the geographic variation in liquid content across that play, whether the well spacing and fracture treatment would resemble those for the Marcellus, and what technologies would be used in Utica shale development (Yost, 2011). These unknowns are significant and

indicate that Utica shale development may proceed differently than Marcellus shale development and utilize different technologies.

The unspecified inclusion of well numbers and productivity figures from the Utica shale also raises questions about the extrapolated employment, housing and tax implications that are attributed to Marcellus shale development.

The issues surrounding productivity are further complicated by the common practice of re-fracturing wells to increase pressure and productivity. If re-fracturing is practiced in New York Marcellus wells, communities will be repeatedly subjected to the environmental disruptions associated with heavy industry.

The uncertainties around and questions raised about long-term well productivity argue for modeling a shorter-term development and production cycle. At the very least, the competing evidence concerning well productivity and the cost of recovery should have been discussed in the RDSGEIS to qualify assumptions concerning the production cycle and estimated ultimate recovery.

A2. Impacts of the Uncertainties Associated with HVHF Gas Development

<u>Evidence from Western shale plays indicates that the volatile pace and scale of natural gas development drives many environmental and social and economic impacts</u> (Best, 2009; Jacquet, 2009; Headwaters Economics, 2010). Impacts directly affected by the pace and scale of drilling include:

1) Labor force needs and behavior. (How much of the workforce remains transient rather than becoming local? A local labor supply cannot develop if gas development is unpredictable.)
2) Demands placed on public services, including health facilities, public safety, and schools. (Can communities adapt over time or are there unpredictable rises and falls in demand?)
3) Community character impacts from increases in traffic, noise, construction disruption, and the transient population. (Do these increases roll out in a regular fashion with the expectation that disruptive “ramp-up” will end or are they unpredictable over a long period of time?)
4) Impacts on rural industries, such as tourism. (Can the scale of noise and traffic be predicted to occur only for a short period or are disruptive activities likely to recur over a longer period of time, for example, with re-fracturing of wells?)
5) Housing demand and cost. (Will there be periodic housing shortages with homelessness and lack of affordable housing for people on fixed incomes, potentially followed by excess housing supply and falling home values?)

To illustrate: As well pad construction begins in an area, jobs increase along with housing construction and business development. A transient population (in addition to transient industry workers) migrates to the area because of the prospect of jobs, increasing the demand for housing and services, including education and health. For a variety of reasons (price of natural gas, availability of higher value opportunities elsewhere, rig availability), natural gas development may drop off in the area within five-ten years of this initial “ramp-up.” Evidence from gas plays in Western states indicates that this drop-off may be sudden. In the wake of this drop in production and the number of drilling rigs in the area, the transient population leaves and resident communities are left without jobs and revenue. Local governments may still be paying the public costs of ramping up to respond to the initial "boom." If conditions change (rigs become available, prices rise), the rigs may return to the area, causing another production "boom" with all of its attendant costs.

This pattern is described by Spelman (2009) and is associated with a reluctance of business (other than the gas industry) to invest in regions characterized by boom-bust economies. A contemporary example of such reluctance is contributing to the housing crisis in the Williston North Dakota Bakken Shale development. According to interviews conducted there: "Developers have been slow to build more apartments, largely because they got stung by the region's last oil boom that went bust in the 1980s." (MacPherson, 2011).

This volatile pattern is dramatically different from the scenario presented in the EAR and RDSGEIS. In both documents, communities are assumed to be impacted by a boom only once (during "ramp-up") and are gradually able to adjust to natural gas drilling. Many of the economic benefits that the RDSGEIS and EAR associate with natural gas development are predicated on this gradual, regular development scenario. For example, the RDSGEIS assumes that as the industry "matures" in the region, local residents will be trained and hired for drilling jobs. If, as has been the case with vertical drilling in New York State and in the Western US shale plays, development follows a more irregular pattern, then the higher paid technical jobs are less likely to evolve into stable local employment. In addition, the jobs in ancillary industries (retail and services) are likely to disappear and reappear as rigs leave and re-enter the region at unpredictable intervals. The RDSGEIS's use of a model built around regular, predictable development of the shale gas resource raises doubts about the projection of economic benefits based on that model.

A3. Hot Spots, Socioeconomic Impacts, and Public Costs

Contrary to the contention that the regularized development model "does not significantly affect the socioeconomic analysis" (RDSGEIS, 6-209), smoothing out the unpredictability and unevenness of development covers up many of the negative cumulative social and economic impacts that arise from the unpredictability of shale gas development. The RDSGEIS admits that steady, constant well construction is "unlikely" (RDSGEIS, 6-209), but it fails to analyze the implications of this admission and offers no description or evaluation of the adverse impacts of temporally and spatially uneven development.

In contrast with the model used in the RDSGEIS, natural gas development does not resemble a "manufacturing" process. Some wells will have long production phases; others will have dramatic declines in productivity after a relatively short period. Well productivity may be uniformly low across a region, or there may be long-term well productivity in particular "hot-spots." The question of how many wells will exhibit long-term productivity and where they will be located is unknown before exploratory drilling takes place and, even then, well productivity will be unpredictable.

The RDSGEIS admits that its socioeconomic analysis is based on average well productivity (RDSGEIS, 6-210), but the production process in natural gas (pace and scale) is not effectively captured using averages. The uncertainties in the geographic extent of drilling and the potential for intensive development in "hot spots" have implications for social and economic impacts. For example, if drilling is concentrated in particular locations rather than rolled out uniformly across sub-regions of the landscape for 60 years (as is modeled in the RDSGEIS and EAR), wealth effects and tax revenues also will be concentrated in particular localities. The social and economic costs of spatially concentrated drilling, however, will be experienced across a much wider geographic area, because public services will be required in areas without HVHF development (and therefore not receiving tax revenues from drilling), but close enough to serve the transient population associated with the industry. There is no attempt to address this likely unbalanced distribution of positive and negative impacts in the RDSGEIS.

Finally, the RDSGEIS does not sufficiently model the resource depletion phase of the exploration, drilling, production, and resource depletion cycle and its implications for local and regional economies. Figure 6.13 (RDSGEIS, 6-215) shows the drop in direct and indirect employment following resource depletion. This depiction needs to be accompanied by analyses of how the resource depletion phase will be reflected in royalty payments and tax revenues.

A4. Socioeconomic Impact Analysis Can Accommodate the Uncertain Pace and Scale of Gas Development

If the impacts of volatility are to be mitigated, their prevalence in natural gas extraction regions needs to be acknowledged in the SGEIS. It is difficult to model the unpredictable pace and scale of natural gas production, but that difficulty is no excuse for ignoring adverse social and economic impacts arising from volatile and unpredictable development. Those impacts have been documented in relation to the phases of exploration, construction and drilling, production, and resource depletion, recognizing the company strategies that produce economic volatility in resource extraction regions (Jacquet, 2009; Kelsey, 2009; Sammons, Dutton and Blankenship, 2010).[1]

In cases where it is not possible to model specific cause-effect relationships (such as the relationship between well development and public costs), but where there is evidence of potential adverse impacts, those impacts should be recognized and documented. Sammons, Dutton and Blankenship (2010) take this approach in their report

[1] From Sammons, Dutton and Blankenship (2010):

> Several recent studies address (social and economic) aspects of natural gas development in the western U.S. They include the *Northwest Colorado Socioeconomic Analysis and Forecasts* prepared for the Associated Governments of Northwest Colorado and the *Sublette County Socioeconomic Impact Study: Phase I Final Report* and *Phase II Final Report,* prepared for the Sublette County, Wyoming Board of County Commissioners. A third report, the *ExxonMobil Piceance Development Project Environmental Assessment - Socioeconomic Technical Report,* prepared by the authors for the U.S. Bureau of Land Management White River Field Office, assesses potential effects of a specific natural gas project in the context of ongoing large scale natural gas development in northeastern Colorado. A more recent journal article, *Energy Boomtowns & Natural Gas: Implications for Marcellus Shale Local Governments & Rural Communities,* published by the Northeast Regional Center for Rural Development, describes a model for impact assessment, presents a case study describing Sublette County's experience with large scale natural gas development and discusses some possible implications for Marcellus Shale development.

commissioned by the New York State Energy Research and Development Authority (NYSERDA) to describe socioeconomic impacts that can be anticipated with HVHF gas development. In addition, NYSDEC needs to quantify known social and economic costs even if their occurrence cannot be synchronized with their scenario model of development. This quantification can be accomplished through examination of comparable cases of impact, a standard method used in fiscal impact analysis (Kotval and Mullin, 2006).

B. NYSDEC's Analysis of Specific Socioeconomic Impacts: Model Assumptions and the Use of Representative Regions

The RDSGEIS presents only a fraction of the material contained in the EAR and acknowledges: "A more detailed discussion of the potential impacts, as well as the assumptions used to estimate the impacts, is provided in the Economic Assessment Report, which is available as an addendum to this RDSGEIS." (RDSGEIS, 6-207). This section identifies questions and concerns regarding the assumptions underlying the model used to predict impacts of HVHF development in New York State. These comments focus particularly on the use of representative regions to project impacts throughout New York State, including those for Utica shale gas drilling.

B1. The Use of Representative Regions

NYSDEC's use of a set of Southern Tier counties to represent all counties in New York that may experience HVHF shale gas drilling (EAR, 6-217) raises concerns about the representativeness of these counties. The EAR and RDSGEIS define three representative regions for the socioeconomic analysis, with Region A representing counties accounting for a high percentage of overall well development, Region B representing counties with about half the development of Region A, and Region C representing counties not expected to have much production but with a history of drilling. In the RDSGEIS, characteristics from a representative region are used to make assumptions about socioeconomic impacts in other New York State regions where drilling may occur. For example, tourism impacts are assumed to be minimal for all regions based on the continued presence of a tourism industry in Region C. The EAR and NYSDEC need to provide evidence (in industrial composition, growth rates, and population composition) to support the assumption that these counties are "representative" of all the counties that may experience drilling.

In addition, the EAR indicates that it addresses "local" impacts, but there is no analysis below the county scale. Analysis of differential economic impacts in urban and rural areas, for example, is critical to understanding the total economic impact picture. For example, counties in Region A in the EAR scenario analysis include both urban areas such as the Binghamton Metropolitan Statistical Area and rural areas where tourism and agriculture are the primary industries. Urban areas will garner more expenditures from natural gas drilling in the region, but are also likely to have negative impacts in the form of increased crime and demand for health services (because of their location in the urban areas). Rural areas will experience intense impacts on their small rural communities, including demand for housing and increases in road damage, as well as potential negative effects on agriculture and tourism. These local impacts, and how the costs and benefits will be distributed, need to be assessed separately.

B2. The Use of a RIMS Input-Output Model to Assess Social and Economic Impacts

A central component of the EAR is use of a Regional Industrial Multiplier System (RIMS) model developed by The Bureau of Economic Analysis. This type of model is useful for comparing different types of investments and for examining inter-industry linkages, but it has a significant drawback as the central model for the RDSGEIS analysis of socioeconomic impacts because it can only project economic benefits. It cannot measure or assess the costs of proposed gas development using HVHF or tell us anything about fiscal impacts.

The purpose of the model is to deduce direct and indirect economic impacts of new expenditures in a region. This type of model is very limited in the types of impacts it can assess. It is typically used to estimate some economic impacts, but is not useful to assess the wide range of social impacts that have been identified as occurring with HVHF shale gas drilling. So, for example, the model can be used to derive population increases and then, to crudely extrapolate potential housing demand. It cannot tell policy makers anything about the impact of housing demand on different population segments or on community character.

The results of this kind of model will always be positive because the model begins with the inflow of expenditures in the region. If the modelers had examined new expenditures flowing into the region's tourism or agricultural sectors those, too, would be positive. The model provided in the RDSGEIS does not allow us to assess opportunity costs, that is, to compare the economic impacts of shale gas drilling with those that might occur with increased investments and expenditures in other industries. This is important not only because shale gas drilling impacts are being considered in "isolation," but because investments in industries such as tourism and agriculture might decrease because of "crowding out" by HVHF activity (Christopherson and Rightor, 2011)

A model of this type is completely dependent on assumptions about the source of expenditures in the region. For example, in the case of HVHF gas development, the model is based on assumptions such as those about where the labor force hired in the drilling phase will spend the money they earn -- in the drilling region or in their home states? These assumptions are critical to the model results and should have been made available so that the accuracy of the model could be analyzed.

The presentation of the model results in the EAR is neither useful nor informative. Much of the text is devoted to tables that present mechanical calculations. These tables should have been relegated to an appendix and the body of the report used to lay out and support the assumptions that underlie the calculations.

In December 2011, the consulting firm that developed the EAR was asked to evaluate costs associated with gas development using HVHF in New York State. Because the RIMS input-output model and the associated scenario approach cannot address the costs of such development, the use of this approach rather than one that addresses costs as well as benefits needs to be justified and re-visited. In addition, because of its inability to address costs, the model does not provide information on impacts that require mitigation. Given the inadequacies of the EAR model and the significance of local and state costs to decisions about shale gas drilling in the state, revised EAR findings regarding costs must be prepared and an opportunity for public review and comment on the revised EAR afforded before the SGEIS is finalized.

C. NYSDEC Analysis of Selected Social and Economic Impacts

This section comments on section 6.8 of the RDSGEIS, which assesses a selective subset of the many social and economic impacts anticipated with HVHF natural gas drilling. These include: (1) economy and employment, (2) population, (3) housing, (4) government revenue and expenditure, and (5) environmental justice. This section concludes with comments on material presented in the EAR that is not discussed in section 6.8, but which is relevant to the RDSGEIS findings regarding social and economic impacts.

C1. Economy and Employment

Employment. The oil and gas industry is not likely to be a major source of jobs in New York, because of the project-based nature of the drilling phase of natural gas production (rigs and crews move from one place to another and activities are carried out at each well) and because of its capital intensity (labor is a small portion of total production costs) (Jacquet, 2009). The emerging information on actual employment created in Pennsylvania in conjunction with Marcellus drilling shows much smaller numbers than industry-sponsored input-output models projected.

Although the industry points to years of drilling experience in New York, the oil and gas industry employed only 362 people in New York State in 2009 (0.01% of the state's total employment) (EAR, 3-7). 43% of those workers (157) were employed in Region C, the region where vertical natural gas drilling is most significant in New York. Wages for these workers constituted 0.04% of the wages in the two-county region with almost 4,000 active gas wells (EAR, 3-31).

The employment multiplier projected for New York State (2.1766) (derived from the model used in the EAR) is exceptionally high, especially for investment from a capital-intensive industry. (A 2.0 multiplier is considered generous by most regional economic analysts.) This underscores the importance of making the assumptions underlying the model transparent. For example, is the basis for the multiplier used an assumption that expenditures on real estate development resulting from the HVHF gas development will accrue disproportionately to New York state firms? If so, why? Because unrealistic and overly optimistic assumptions made in constructing the models may overstate economic benefits, assumptions underlying this RIMS model need to be available for scrutiny.

Finally, the employment figures presented in Table 4-8 are "full–time-equivalent" (FTE) jobs. These jobs do not correspond with what the ordinary person thinks of as a job – a person employed full-time to carry out certain tasks. They are a composite of part-time and full-time jobs that might be developed from the 410 job activities associated with constructing and drilling a well and from the subsequent production phase. These may not be new jobs, but existing jobs required to sustain industry activity. Finally, the EAR does not provide sufficient context for evaluating the employment impact of gas development using HVHF in the state. Projected employment in HVHF development should be compared with that in other New York industries, including tourism, to place the numbers in perspective. Projected increases in employment in these other industries should be provided to enable comparison and to estimate costs and benefits of permitting HVHF gas development.

Impacts on other regional Industries. Having described in detail the modeled economic and employment growth from the gas industry, the RDSGEIS then mentions the potential adverse impacts on existing industries in the regions where natural gas development will occur. In a bare two paragraphs, the RDSGEIS admits:

> Conversely, some industries in the regional economies may contract as a result of the proposed natural gas development. Negative externalities associated with the [sic] natural gas drilling and production could have a negative impact on some industries such as tourism and agriculture. Negative changes to the amenities and aesthetics in an area could have some effect on the number of tourists that visit a region, and thereby impact the tourism industry. However, as shown by the tourism statistics provided for Region C, Cattaraugus and Chautauqua Counties still have healthy tourism sectors despite having more than 3,900 active natural gas wells in the region.
>
> Similarly, agricultural production in the heavily developed regions may experience some decline as productive agricultural land is taken out of use and is developed by the natural gas industry.

(RDSGEIS, 6-230).

In contrast with the pages of projected benefits from gas development, the RDSGEIS offers no detailed description and no quantitative analysis of the effects of HVHF development on existing industries and the associated impact on the state of New York's economy. This omission is particularly important for the counties defined in the EAR as "representative" because industries, including agriculture and tourism, are significant employers in those counties and are important to the overall economy of the State. There is no analysis of how the "crowding out" of existing industries may impact the regional or statewide economy or of the implications of the loss of industrial diversity to the long-term prospects for regional economic sustainability.

The inadequate assessment of the impacts on existing industries in the region that will be affected by HVHF gas development is problematic not only because the state does not have adequate information to assess costs and benefits of HVHF gas development, but also because negative impacts on industries such as tourism and agriculture, including dairies and wineries, will undermine state investments intended to support those industries. As discussed in detail below, given the importance of these industries in the state and regional economy, the evidence that they will be negatively affected by HVHF gas development should have been analyzed in detail and quantified when possible.

Tourism. The RDSGEIS makes no effort to quantify the value of tourist activities that may be adversely affected by gas development but rather dismisses any impacts as insignificant.

Nearly 674,000 New York jobs were sustained by tourism activity last year, representing 7.9% of New York State employment, either directly or indirectly. New York State tourism generated a total income of $26.5 billion, and $6.5 billion in state and local taxes in 2010.

Tourism in the Southern Tier counties includes a wide range of activities, from visits to the Corning Glass Museum to hiking, hunting, and fishing in the rural areas. The Southern Tier Central (STC) Planning District, which includes Chemung, one "fairway" county (where significant natural gas drilling is anticipated because of the geologic formation) located in Region A in the RDSGEIS analysis, has published a study indicating that:

> In 2008, visitors spent more than $239 million in the STC region across a diverse range of sectors. The tourism and travel sector accounted for 3,335 direct jobs and nearly $66 million in labor income in the STC region that year. When indirect and induced employment is considered, the tourism sector was responsible for 4,691 jobs and $113.5 million in labor income. In addition, the travel and tourism sector generated nearly $16 million in state taxes and $15 million in local taxes, for a total of almost $31 million in tax revenue -- a tax benefit of $1,181 per household.

(Rumbach, 2011, page 1).

Tourism is thus a significant contributor to the counties in New York potentially impacted by HVHF gas development. The tourist opportunities and activities also contribute to the quality of life of local residents and attract companies in other sectors, such as manufacturing.

NYSDEC's use of Chautauqua and Cattaraugus Counties as the basis for contending that tourism will not be significantly impacted in New York is not persuasive. First, the evidence offered for the judgment that those counties have "healthy tourism sectors" (RDSGEIS, 6-231) consists of nothing more than the statement that: "In 2009 wages earned by persons employed in the travel and tourism sector in Chautauqua and Cattaraugus counties (Region C) were approximately $77.5 million, or about 3.0% of all wages earned in Region C" (NYSDOL 2009b*)* (see Table 3-37)" (EAR, 3-27). Without comparing Chautauqua and Cattaraugus over time with similar counties where natural gas development has not taken place, it is impossible to determine whether the tourism sector of the Region C counties has been negatively impacted by shale gas drilling.

The contention that those counties represent a tourism success story is contradicted by data presented in the EAR, which shows that from 2007 to 2009, Region C tourism employment declined 17%, and wages declined 13% (EAR, 3-28). While a portion of this decline might be attributable to the recession, there is no justification for describing waning tourism in the region as "healthy."

In addition, there is growing evidence regarding the negative effects of shale gas drilling on tourism in the counties where shale gas drilling takes place (Rumbach, 2011).

> Evidence from other shale plays in the Western U.S. indicates that natural habitat tourism (whether hunting, fishing, birding or hiking) may be disrupted for long periods of time and in some cases where infrastructure, such as compressor plants and pipelines, disrupts habitats, may be permanently altered.

(Sammons, Dutton and Blankenship, 2010). Negative impacts derive not only from the loss of habitat for outdoor sports, but also from the "crowding out" of tourism activities (because of increasing prices in the drilling region and the loss of hotel spaces to gas industry workers) and from the impact of regional industrialization on the tourism brand. For example, tourism centers in Upstate New York, such as the Finger Lakes wineries, may experience losses when tourists looking for a rural retreat find themselves driving through an industrial region with heavy truck traffic and shift their allegiance to quieter and more accessible vacation spots. In addition, the RDSGEIS does not assess the impacts on tourism from degradation of historical and cultural assets.

The EAR also conflates access to private recreational land for purposes of hiking, hunting, and fishing with the success of commercial tourism businesses. The relationship between personal recreational opportunities and natural gas development is presented as one of personal trade-offs in terms of land use. The negative impacts on the options of non-land owning recreationists are mentioned but not addressed (EAR, 4.58).

Rumbach's assessment of HVHF gas development on tourism is that:

> ….individual impacts are unlikely to have serious and long-term consequences, but without mitigation, cumulatively they could do substantial damage to the tourism sector. Examples of such impacts include strains on the available supply and pricing of hotel/motel rooms, shortfalls in the collection of room (occupancy) taxes, visual impacts (including wells, drilling pads, compressor stations, equipment depots, etc.), vastly increased truck and vehicle traffic, potential degradation of waterways, forests and open space, and strains on the labor supply that the tourism sector draws from. All told, the region's ability to attract tourists could be damaged in the long-term if the perception of the region as an industrial landscape outlasts the employment and monetary benefits of gas drilling.

(Rumbach, 2011, page 2).

The RDSGEIS fails to address the long-term costs associated with displacing business in existing industries, such as tourism, that provide economic diversity in the regional economy and thus increase its prospects for sustainability.

<u>Agriculture</u>. <u>Potential negative impacts on agricultural production and land use are noted, but their impact is not assessed nor are any mitigation measures proposed (RDSGEIS, 6-231). There is no analysis of whether and how HVHF gas development will affect sub-sectors of agriculture, such as dairy farming, which are of key importance in the New York economy</u>.

Milk and other dairy products account for more than half the total value of agricultural products sold in New York State, accounting for $2.2 billion in receipts in 2010. According to the US Department of Agriculture, New York ranks third in the US in production and sale of dairy products. Certainly the size and importance of this industry to the New York economy warrants a full analysis of how production and producers will be impacted by HVHF gas development. Instead, the RDSGEIS lacks an economic assessment of how temporary and long-term agricultural costs and productivity will be affected by HVHF development.

Recent evidence from Pennsylvania indicates that agriculture and particularly dairy farming may be significantly affected by drilling activity. For example: "(Bradford) county's dairy herd has decreased over the last decade from 30,000 head in 2002 to just under 20,000 head today. Another 15 dairies have been sold since the beginning of the year (2011)" (Tomes, 2011). Although evidence from Pennsylvania is anecdotal, there is sufficient information to indicate that one of New York's major industries will be negatively affected by HVHF gas drilling.

Dairy farms are decreasing in areas with natural gas development both because some farmers have another source of income and because costs for dairy farmers are going up as a consequence of the impact of the drilling economy in the county. For example, competition for truck drivers is raising the cost for dairy farmers to transport their milk to processors. In addition to the impacts on the dairy farms themselves, the infrastructure that supports dairy farming in Bradford County is being affected. For example, an agricultural equipment dealer in the County has gone out of business because of an inability to hire and retain a workforce (Tomes, 2011).

There are also land use impacts that affect farmers, including impacts not only from the well pads, but also from the ancillary industrial facilities, such as "laydown yards" (operations and storage sites), pipelines, and compressor stations (Tomes, 2011).

The American Farmland Trust (2011) has submitted comments on the RDSGEIS that summarize its expert assessment of the impact on agricultural production in New York State:

> …the DEC's analysis of the impacts of drilling and hydraulic fracturing to agricultural land is inadequate and encourages specific analysis of the likely impacts of such activities to agricultural land resources. The SGEIS analysis should consider the scale of farmland likely to be converted by both direct drilling activities and the off-site drilling support services and other types of residential and commercial development that is anticipated as a result of natural gas drilling. In addition, it should consider the impacts of such activities to agricultural land values and on the ability of New York farmers to maintain their competitiveness in a global economy.

Upstate New York is currently experiencing a resurgence in its food processing industry, and the State Agricultural and Markets Program has a stated policy of encouraging more dairy production in the state. In July 2011, the State of New York provided $16 million in incentives to a dairy processing company in Chenango County in Central New York. According to a statement by Governor Cuomo: "Agro Farma's expansion in Chenango County will create hundreds of new jobs and increase the demand for milk from New York dairy farms," (press release available at: http://www.governor.ny.gov/press/07212011DairyProductsCompany).

The support from New York's Empire State Development Corporation reflects the significance of this industry to the regional and state economy. A full economic assessment of potential impacts to this industry is warranted. This assessment should include labor costs (from competition for truckers, for example) and impacts on specialty agricultural producers, such as organic farmers. New York State has the fourth largest number of organic farms in the U.S.

The Finger Lakes wineries, combining agriculture and tourism, are another important subset of New York industries that may also be affected by HVHF gas development in Upstate New York. New York State ranks third nationally in grape production. Tourists visiting the wineries may not want to drive through industrial development and its associated truck traffic in order the reach the wineries, even if the wineries are not locally impacted by the drilling process. Given the importance of this and other sectors of New York's agricultural industry to the Upstate New York "brand" and the investment of State resources to build the industry, the SGEIS needs to separately assess the impacts on this industry and develop mitigation policies to address the negative impacts identified.

Manufacturing. Finally, the RDSGEIS and the EAR focus exclusively on impacts to agriculture and tourism because the use of land by those industries potentially competes with use of land for gas development. Focusing on that competition may make sense for the largely rural representative regions defined in the EAR, but it does not make sense for representative regions with more diversified economies, including substantial manufacturing. A report by the New York State Comptroller's office in 2010 shows that the Southern Tier has 14% of Upstate manufacturing. Manufacturing should be included in the assessment of impacts on existing industries, because of its significance in Region A and because gas development will affect the labor supply and industry wage rates in counties where manufacturing plays a significant role in the economy.

C2. Population

The RDSGEIS and EAR do not address population impacts on community services, such as schools and health, but only population as it relates to employment and the labor market. There was no attempt to look at actual population trends in counties with significant gas drilling and whether they reflect a decline in economic diversity that makes population levels less sustainable. An analysis of the long-term population trends in shale gas drilling counties in the US is necessary to determine the impact of HVHF gas development on New York counties. A projection based on labor demand is not sufficient.

The EAR assumes that, for the first 30 years, the population increases in counties that "host" natural gas drilling will be modest. It notes, for example:

> [A]ctual population impacts may also be less than what is described in the following section because currently unemployed or underemployed local workers could be hired to fill some of the construction and production positions, thereby, reducing the total in-migration to the region.

(EAR, 4-59).

By focusing only on population changes directly related to gas industry employment, the RDSGEIS avoids addressing the potential for long-term population decline beyond the loss of industry workers. Many areas with significant natural gas drilling lose population over time. That has been the case with Chautauqua and Cattaraugus counties (Region C) in New York.

In addition, the RDSGEIS assumes a gradual (rather than disruptive) integration of the unemployed population in the region and of transient workers into the labor force required by the industry. Experience from other states, however, contradicts the assumption of easy integration of the resident workforce and of newcomers to the regional labor force: "In areas of Pennsylvania where Marcellus shale drilling activity is occurring, it has been difficult at times to accommodate the influx of new workers" (Kelsey, 2011). The potential for a low-skilled, transient workforce to migrate into the area is not considered, although there is evidence from Western shale plays that this occurs, and is particularly likely with high national unemployment rates.

> [B]ecause labor markets are imperfect, [and] the availability of a relatively large number of jobs may result in an influx of job seekers, some of whom lack necessary skills and qualifications and may be relatively indigent. To the extent that indigent job seekers are unable to find jobs or do not have resources to secure housing and transportation to work; they can become a burden for local human service agencies. This situation can be exacerbated by weak economic conditions in other parts of the state or country.

(Sammons, Dutton and Blankenship, 2010, page 13).

The RDSGEIS fails to address this evidence of adverse economic impacts.

C3. Housing and Property Values

<u>The potential impacts on the housing supply, housing costs, and housing financing are inadequately assessed in the EAR. In addition, the social and economic impacts of unpredictable shortfalls in housing followed by periods in which there is an excess supply are not addressed.</u>

The report assumes that the current housing stock would be used to house any workers who move to the production region on a "permanent" (more than one year) basis (EAR, 4-107 (concluding "the impact on the supply of permanent housing units would be negligible at the statewide level during the production phase")). Given the quality and age of the housing stock in the region, evidence from Pennsylvania indicates that it is likely that there will be a demand for new single-family housing (Kolb and Williamson, 2011). This new housing stock will create new and additional construction jobs, increasing population pressure, accelerating the "boomtown" phenomenon. This housing may also contribute to sprawl around urban population centers such as Binghamton. When drilling ceases, either temporarily or permanently, the value of this new housing is likely to plummet (Best, 2009).

With respect to temporary housing, the EAR (EAR, 4-111) admits:

> In areas of Pennsylvania where Marcellus shale drilling activity is occurring, it has been difficult at times to accommodate the influx of new workers (Kelsey 2011). There have been reports of large increases in rent in Bradford County, Pennsylvania, as a result of the influx of out-of-area workers (Lowenstein 2010). There have also been "frequent reports" of landlords not renewing leases with existing tenants in anticipation of leasing at higher rates to incoming workers, and reports of

> an increased demand for motel and hotel rooms, increased demand at RV camp sites, and increases in home sales (Kelsey 2011). Such localized increases in the demand for housing have raised concerns about the difficulties caused for existing local, low-income residents to afford housing (Kelsey 2011).

If communities add substantial temporary, short-term housing or single-family housing to accommodate development-phase workers, surplus capacity may exist in all these types of units after development is completed. Based on evidence from other shale gas plays, all of these adverse impacts (initial housing shortage, surplus supply if rigs leave temporarily and depressed value in some areas) may occur (Best, 2009; Sammons, Dutton and Blankenship, 2010).

The EAR (EAR, 4-111) also acknowledges the potential impact of the volatility of the production cycle on the housing market and property values:

> The demand for housing, both temporary and permanent, would be expected to change over time. The demand for housing would be the greatest in the period during which the wells in an areas are being developed, and demand would decline thereafter. This would create the possibility of an excess supply of such housing after the well development period (Kelsey 2011). If well development in a region occurs in some areas earlier than in others, then housing shortages and surpluses may occur at the same time in different areas within the same region.
>
> The natural gas market can be volatile, with large swings in well development activity. Downswings may cause periods of temporary housing surplus, while up-swings may exacerbate housing shortages within the regions.

A recent study of the impact of HVHF gas development in Pennsylvania indicates that impacts on the housing supply are significant, especially for people at the economic margins (Williamson and Kolb, 2011). These impacts pose environmental justice concerns and require mitigation strategies.

With respect to impacts on property value, the EAR authors found that having a well on a property was associated with a 22% <u>reduction</u> in the value of the property; that having a well within 550 feet of a property increased its value; and that having a well located between 551 feet and 2,600 feet from a property had a negative impact on a property's value. Thus,

> …not all properties in the region would increase in value, as residential properties located in close proximity to the new gas wells would likely see some downward pressure on price. This downward pressure would be particularly acute for residential properties that do not own the subsurface mineral rights (EAR, 4-114).

The EAR authors attributed the positive impact on property values of having a well located within 550 feet of a property to <u>the prevention of further gas well development</u> in that area due to a spacing order and setback conditions that prevented well drilling close to existing wells.

The assertion in the EAR that property owners in the drilling region would see an overall increase in property values is based on increased demand and economic activity. Evidence from Pennsylvania and from Western Shale plays indicates that this demand may not occur in the county or locality where the drilling is occurring (Patton et al, 2010).

The EAR's assumption of recovering property values after the completion of HVHF gas development does not take into account the potential for re-fracturing of wells to increase their productivity or the effects of waves of development in which drilling moves in and out of an area. The prospect of industrial activity is what drives down investment in regions open to boom-bust development and also negatively impacts property values (Spelman, 2009). A more definitive analysis of impacts of on property values, including mortgage availability, in regions affected by drilling is needed.

C4. Government Revenues and Expenditures

The RDSGEIS assumes, based on the RIMS model, that economic benefits from HVHF gas development, presumably including benefits to revenue, will be substantial, but there is no fiscal impact analysis or cost-benefit analysis to substantiate that assumption. A fiscal impact analysis is required, given that:

(1) Many purchases by drilling companies are tax exempt (EAR, 4-116).

(2) Costs to the state that will reduce or offset tax revenues are not calculated. For an example of this problem, see the discussion of rail infrastructure in the RDSGEIS section on transportation impacts. The provision of tax rebates to railroad companies and to industry facilities represent lost revenue to the State and the locality. The EAR admits that in addition to tax benefits, "such as expensing, depletion, and depreciation deductions," which reduce taxable income, "New York State offers an investment tax credit (ITC) that could substantially reduce most, if not all, of the net income generated by these energy development companies" (EAR, 4-115 to 4-116).

(3) Substantial negative fiscal impacts are detailed in the EAR that are not quantified or fully acknowledged in the SGEIS:

> High-volume hydraulic fracturing operations would also result in some significant negative fiscal impacts on the state. The increased truck traffic required to deliver equipment, supplies, and water and sand to the well sites would increase the rate of deterioration of the state's road system. Additional capital outlays would be required to maintain the same level of service on these roads for their projected useful life. Depending on the exact location of well pads, the state may also be required to upgrade roads and interchanges under its jurisdiction in order to handle the additional truck traffic. The potential increase in accidents and potential additional hazardous materials spills resulting from the increased truck traffic also would require additional expenditures. Finally, approval of transportation plans/permits would place additional administrative costs on the New York State Department of Transportation (EAR 4-116).

There are now numerous studies available to calculate road damage, and the counties in the "fairway" in New York State have undertaken baseline studies that would enable accurate calculation of the costs of road damage (Randall 2011). There is plenty of expertise available in the state to draw on, including Cornell Local Roads program, which has completed a thorough analysis of the kind of damage and what it would cost to repair.

The EAR also recognizes additional public costs associated with Marcellus shale gas development:

> Additional environmental monitoring, oversight, and permitting costs would also accrue to the state. In order to protect human health and the environment, New York State would be required to spend substantial funds to review permit applications; to ensure that permit requirements were met, safe drilling techniques were used, and the best available management plans were followed; and to provide enforcement against violations. In addition, the state would experience administrative costs associated with the review of well permit applications and leasing requirements and enforcement of regulations and permit restrictions. All of these factors could result in significant added costs for the New York State government.
>
> The New York State Department of Health would also incur additional costs due to the need to provide additional technical support and oversight services to local governments that would monitor water quality in local drinking water wells (EAR, 4-116).
>
> In addition to the positive fiscal impacts discussed above, local governments would also experience some significant negative fiscal impacts as a result of the development of natural gas reserves in the low-permeability shale. As described in previous sections, the use of high-volume hydraulic-fracturing drilling techniques would increase the demand for governmental services and thus increase the total expenditures of local government entities. Additional road construction, improvement, and repair expenditures would be required as a result of the increased truck traffic that would occur. Additional expenditures on emergency services such as fire, police, and first aid would be expected as a result of the increased traffic and construction and production activities. Also, additional expenditures on public water supply systems may be required. Finally, if substantial immigration occurs in the region as a result of high-volume hydraulic fracturing operations, local governments would be required to increase expenditures on other services, such as education, housing, health and welfare, recreation, and solid waste management to serve the additional population (EAR, 4-138).

The RDSGEIS mentions public costs associated with the increased demand for community social services, police and fire departments, first responders, schools, etc., but makes no attempt to calculate the costs and consider them in the context of a fiscal impact assessment. Experience in other shale gas plays demonstrates that these costs are likely:

> Natural gas development and production-related activities and the incremental population associated with those activities will generate

> demand for the full range of local government facilities and services and for some state government services. For example, during exploration and moderate stages of development, demand is usually limited to law enforcement, emergency response, emergency medical and road and highway maintenance and traffic control. Traffic, vehicle and industrial accidents and issues associated with a single-status, predominately working-age male workforce are the primary drivers associated with emergency response and law enforcement increases. Because many workers are temporary, and do not have local general purpose health care providers, they commonly use hospital emergency rooms for what would be otherwise be routine health care visits.

(Sammons, Dutton and Blankenship, 2010, page 19).

This knowledge regarding public costs and fiscal impacts should have been reflected in the RDSGEIS. These costs may occur even if the amount of commercially extractable natural gas does not reach projected levels. They need to be calculated both in terms of the baseline costs that are likely to occur with <u>any</u> drilling activity and in relation to varying levels of drilling activity.

Addressing the variability is important because there are distinct community character impacts attributable to large-scale development that have been identified and documented in other shale plays.[2] For example:

> …some areas that experience large scale development have reported substantial increases in a variety of crime and social problems including alcohol and drug-related offenses, traffic offenses, disturbances, assaults and domestic conflicts. Although some increases in crime and social problems would be anticipated to accompany any increase in population, some researchers have also attributed the increased levels of crime and social problems to the temporary and transient nature of the workforce and their living conditions. There has been some debate in the social impact assessment literature about whether or not crime and other adverse social indicators increase at higher rates in communities experiencing large-scale development than average rates for all communities. But the implications are clear that increases in crime and social problems are likely with large-scale development, even if they are proportionate to the increase in the numbers of people working and living in affected communities.

(Sammons, Dutton, and Blankenship, 2010).

Given the scale of development being projected, the thresholds for community costs and

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[2] *See* Sublette County Socioeconomic Impact Study Phase I Final Report. Ecosystem Research Group. , January 2008. Pages 54 – 58 and Index Crimes, Arrests, and Incidents in Sublette County 1995 to 2004: Trends and Forecasts, Prepared by J. Jacquet. Sublette County, Wyoming, April 2005, *available at:* http://www.sublettewyo.com/DocumentView.aspx?DID=351; Local Social Disruption and Western Energy Development: A Critical Review, Wilkinson et.al. Pacific Sociological Review Volume 25. July 1982. *available at:* http://www.sublettewyo.com/archives/42/Local_Social_Disruption__Critical_Review_Response_and_Commentary [1]. pdf.

adaptation to the impacts related to population increase or demand for services (administrative, school, health, public safety) must be addressed by the SGEIS. Evidence from Pennsylvania indicates that ability to adapt to these community social and economic impacts is critical to short-term and long-term community well-being (Kolb and Williamson, 2011; Kelsey, 2010, 2011).

(4) Costs will vary with the nature of population increases driven by the permitting of HVHF gas development. For example, indigent job seekers unable to find jobs and without resources to secure housing or transportation to work can become a burden for local human service agencies. This situation may be exacerbated by weak economic conditions in other parts of the state or country.

An example of this phenomenon is documented in a study carried out by Guthrie Hospital/Troy Community Hospital in Bradford County, Pennsylvania, where impacts from HVHF gas development in the county have significantly increased demand for health services (Covey 2010). The hospital is treating a new non-English speaking clientele and has had to hire translators. They have also had to purchase new equipment and have experienced a significantly increased demand on their emergency room services. The new demand affects not only the bottom line of providers, but also the availability of and access to health care for residents of the region in which drilling is occurring.

(5) There is no analysis of the expected lag between immediate costs and anticipated revenues. This lag may be 2-3 years, during which communities will be faced with significant public service costs.

(6) A tax profile needs to be presented over time, not one for a single year, in order to understand how natural gas drilling has fiscally impacted Region C, where most wells are currently located and where wells have increased.

C5. Environmental Justice Impacts

A section on Environmental Justice, included at the end section 6.8 of the RDSGEIS, notes that well permits are currently exempt from screening under NYSDEC Commissioner Policy 29, Environmental Justice and Permitting (CP-29) (RDSGEIS, 6-263). NYSDEC suggests that a drilling permit applicant could, “when necessary,” conduct a GIS analysis to identify potential environmental justice areas. The RDSGEIS should set forth criteria to determine when such an analysis would be “necessary” and should include the requirement in standard permit conditions or regulations. Moreover, given the known housing impacts of gas development on low-income populations, efforts to mitigate significant adverse environmental justice impacts must include not only the “additional community outreach activities” required in the RDSGEIS, but also substantive measures to prevent dislocation and homelessness.

II. Additional Economic Impacts Identified in the EAR But Not Addressed in the RDSGEIS

The RDSGEIS presents only a fraction of the material contained in the EAR and acknowledges: “A more detailed discussion of the potential impacts, as well as the assumptions used to estimate the impacts, is provided in the Economic Assessment Report, which is available as an addendum to this SGEIS" (RDSGEIS, 6-207). This section comments on material presented in the EAR that is not discussed in section 6.8, but which is relevant to the RDSGEIS findings regarding social and economic impacts.

A. The Distribution of Impacts of HVHF Gas Development in New York State

The socioeconomic impact analysis should systematically describe the geographic distribution of impacts. In New York, as is explained below, the creation of high-paying jobs as a result of expenditures in industries outside the extraction industry is likely to occur outside the production region. This is important because regions where natural resource extraction takes place (and especially rural regions with little economic diversity) have been found to end up with poorer economies at the end of the resource extraction process (Best, 2009; Sammons, Dutton and Balnkenship, 2010). Mitigation measures need to be identified to address long-term costs to the rural counties where extraction will be concentrated.

The EAR calculates the impact of a $1 million increase in the final demand in the output of the oil and gas extraction industry on the value of the output of other industries in New York State (EAR, 3-6). The EAR then makes a series of statements concerning where the economic benefits of HVHF development are expected to occur. For example:

> The proposed use of high-volume hydraulic fracturing would have a significant, positive impact on employment in New York State as a whole and in the affected communities. However, the distribution of these positive employment impacts would not be evenly distributed throughout the state or even throughout the areas where low-permeability shale is located. Many geological and economic factors would interact to determine the exact locations where wells would be drilled. The location of productive wells would determine the distribution of impacts.

(EAR, 4-46; emphasis added).

The location of wells is, however, only one factor affecting the distribution of economic impacts in New York State. Many wells are drilled in rural areas with no or very limited commercial services near-by. If that is the case, then the economic impacts (in the form of expenditures by drillers and companies) will not occur close to the drilling site. Some will occur in centers – perhaps across a municipal or county line – where there are stores and restaurants that the drilling company employees use for meals and supplies. Some economic impacts will occur in far away places, such as New York City, where the drilling company can buy specialized services, such as tax accounting and legal services, to meet their business needs.

This potentially broad distribution of economic impacts is reflected in the multipliers reported in the EAR as follows:

> As anticipated, the direct effect employment multiplier for the State of New York (2.1766) was substantially larger than the multipliers for the individual regions, which had direct-effect employment multipliers of 1.4977 in Region A, 1.3272 in Region B, and 1.4357 in Region C (USBEA

2011a, 2011b, 2011c, 2011d). (EAR, 4-19).

These multipliers are affected by purchases by the gas drillers from other industries in the economy. In this case, the RIMS model used in the EAR indicates that three largest industries in which purchases will be made (and additional employment created) are: (1) real estate and rental; (2) professional, scientific, and technical services; and (3) management of companies). We can anticipate that purchases from these industries would have a strong effect in New York State as a whole because these industries have a strong presence in New York State.

<u>What the multipliers also tell us, however, is that the jobs indirectly created by purchases of goods and services by the natural gas developers are not likely to be located in the counties where HVHF gas development occurs</u>. Multipliers tell us how strong the industry is in a region or state. Higher multipliers indicate that those businesses that the oil and gas industry is likely to purchase goods and services from are present. Lower multipliers indicate a small industry presence and thus a lower likelihood of purchases in that geographic area. So, for example, a natural gas development company would employ professional services as a consequence of expanding drilling in Chautauqua County, but is likely to go to New York City to purchase those services because they are more likely to be available in New York City. Companies providing professional services in New York City are more likely to stay there rather than move to the Southern Tier because they have more opportunities to attract diverse industries to their specialized services in New York City than in Elmira or Jamestown.

<u>If the EAR seeks to project the impact of expenditures on the regions in the state likely to be affected by HVHF gas development, it needs to disaggregate these impacts to show what proportion of the impacts in the three largest sectors (real estate and rental; professional, scientific, and technical services; and management of companies) is actually likely to occur in the representative regions</u>. Although the authors assert that as the natural gas industry grows, more of the suppliers would locate to the representative regions and less of the indirect and induced economic impacts would leave the regions, no evidence is presented to substantiate this assumption. This assumption contravenes economic knowledge about agglomeration economies and company location behavior, which indicates that specialized services will remain in higher order centers (like New York City) and not re-locate to counties, especially rural counties, where drilling is occurring. The more likely outcome is indicated by a study of the impact of gas drilling on Western State economies, which found that <u>natural gas drilling may have positive fiscal impacts at the state level, but negative fiscal impacts for the regions in which it occurs</u> (Headwaters Economics, 2011).

B. <u>The Distribution of Economic Impacts in New York Versus Those in Other States</u>

Nationally, Texas and Oklahoma are the major beneficiaries of natural gas development, wherever production takes place in the United States. According to *Mine K. Yücel and Jackson Thies of* the Dallas Federal Reserve (2011): "An increase in oil and gas production **<u>anywhere</u>** benefits the state (of Texas) and its energy sector, which provides oilfield machinery and energy services to the rest of the world." See also subsection C, below. Nevertheless, because of its capital intensity, natural gas drilling does not have a large employment impact, even in Texas. Gas development thus plays a minor role in the economies of even these resource extraction states.

C. The Distribution of Highly-Skilled Jobs

Petroleum engineers are listed as one of the most common occupations in the oil and gas industry (EAR, 3-8, Table 3-10). The geographical analysis of this occupation by occupational employment statistics indicates that the states with the highest employment in this occupation are Texas, Oklahoma, and Louisiana. In 2010, the total U.S. employment of petroleum engineers was 28,210, of which 15,510 were employed in Texas, and 10,380 of those worked in the Houston metropolitan area. Thus, even in Texas, the employment in this occupation is concentrated in the Houston metropolitan area, not in the drilling areas.

The likely distribution of highly paid occupations is demonstrated by the Bureau of Labor Statistics (BLS) Occupational Employment Statistics Data on one of the most numerically significant skilled occupations, that of petroleum engineer. According to the BLS, only a fraction of petroleum engineers (in the hundreds) are employed in non-metropolitan areas in the U.S. (BLS, 2010). This data, too, suggests that the rural areas of New York that are likely to experience the most intensive gas development will not see an increase in highly skilled and highly paid jobs related to the oil and gas industry.

III. Inadequacy of Proposed Mitigation Measures

A. Mitigation Measures That Address Potential Impacts Related to Volatility in the Pace and Scale of Drilling Should Be Required

The mitigation chapter of the RDSGEIS implies that negative impacts will be mitigated through the permitting process and a secondary level of review triggered by the operator's identification of inconsistencies with comprehensive land use plans. The measures identified are only advisory. The RDSGEIS proposes no requirements to mitigate adverse socioeconomic impacts in this process.

Mitigation measures should be developed that would require operating companies to submit plans for exploration and development in a county or counties to county planning offices for review of cumulative impacts and mitigation (for example truck traffic routing), a model used in Western U.S. drilling regions (Headwaters Economics, 2011). This assessment is also completed for National Environmental Policy Act compliance when development proceeds on public lands.

Because the RDSGEIS acknowledges that the pace and scale of development are difficult to ascertain until exploration and production begin to proceed, it is critical that a permit and regional Plan of Development (POD) review process be set up that alerts local officials to the need for long term planning for land use, schools, public safety and public health. The POD, outlining the pace, scale, and general location in which development will occur, enables local government to anticipate and develop strategies to mitigate cumulative impacts (Sammons, Dutton and Blankenship, 2010). The near-term projections of development activity should include all secondary facilities (e.g., water extraction, waste disposal, pipeline construction) in the area to be affected.
A POD would allow communities in that region to prepare for the disruption and negotiate the least disruptive and damaging development plan.

Another mechanism for reducing the unpredictability and uncertainty of natural gas production at the regional scale is being developed by the Nature Conservancy with pilot projects in the Western States and planned in Pennsylvania (see Kiesecker et al, 2010). Their objective is a science-based, landscape-scale approach to Marcellus gas development that will secure measurable conservation outcomes, while enhancing industry's ability to operate in an environmentally sensitive and cost-efficient manner. To be enforceable, this cooperative approach, based on a partnership between the operating company and local public officials, needs to be codified in a binding agreement. Partnerships of this sort may be useful, but they cannot serve as mitigation for significant adverse socioeconomic impacts unless they are mandatory.

B. Mitigation Should Address Housing and Urban Development Impacts, Including Sprawl and Excess Substandard Housing

Evidence from Pennsylvania and Western shale plays indicates the likelihood of negative impacts on the quality of the temporary and permanent housing stock, a high rate of homelessness for extensive periods, and displacement of low income people from affordable housing. Given the presence of small cities in the region, mitigation measures should include required assistance to cities in the affected region to encourage new housing development in already-developed urban areas and the development of temporary housing that could be transformed to other uses once the influx of transient workers resides. Mitigation measures should also address the impacts of the loss of affordable housing units in the region.

C. Mitigation Should Address Long-Term Social and Economic Impacts

The RDSGEIS and the EAR describe significant adverse social and economic impacts, such as those produced by the volatility of natural gas development on the housing market of regions where development occurs. No mitigation strategies are recommended to alleviate long-term costs that are reasonably assumed to be associated with natural resource development, including HVHF development. Mitigation strategies directed at these long-term costs to the affected regions need to be developed and described in the SGEIS. Mitigation strategies also need to be developed to address the resource depletion phase of the exploration, drilling, development and resource depletion process. In this phase, population and jobs leave the region and tax revenues may be insufficient to pay for the capital investments made to serve the population influx during the drilling and production phases of development. Mitigation strategies should include policies to prevent negative impacts on existing industries, including agriculture, tourism and manufacturing.

D. Mitigation Should Require That Monitoring Reports Projecting Industry Development Plans Be Prepared by the State in Cooperation with Industry and Filed Semiannually

As development activities begin and progress, the information provided in initial projections should be required to be confirmed or revised on a semiannual basis. Information provided in the semiannual assessment and projection should include: (1) employment for each activity; (2) identification and location of contractors; (3) demographic characteristics and residence of employees who will be working in the region. This information is critical to forecasting and meeting housing and service demands.

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Attachment 6

Meliora Design, LLC.

Technical Memorandum

Review and Analysis of the

Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas, and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs

and the

Draft New York State Department of Environmental Conservation SPDES General Permit for Stormwater Discharges from High-Volume Hydraulic Fracturing

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Introduction

This memorandum reviews both the *Revised Draft Supplemental Generic Environmental Impact Statement* (RDSGEIS) *on the Oil, Gas and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs* and the Draft *New York State Department of Environmental Conservation SPDES General Permit for Stormwater Discharges from High-Volume Hydraulic Fracturing* (SPDES HVHF GP). The focus of this memorandum is the potential impacts on surface water resources that result from land disturbance and alteration, including impacts related to increased erosion and sedimentation, as well as impacts that result from increased and altered stormwater discharges. The review of both the RDSGEIS and the Draft SPDES HVHF GP are co-dependent, as the Department has indicated that general or (substantially similar) individual SPDES permit coverage will be the primary means of regulatory oversight for HVHF operations (and presumably for other low-volume hydraulic fracturing activities, although this is not explicitly stated).

The land disturbance associated with HVHF construction activity has the potential to negatively impact surface water quality in the same manner as other land disturbance activities, as discussed in Attachment A, and the lack of a local government land development review process increases the potential for greater water quality impacts through the increased disturbance of steep slopes, sensitive areas, proximity to unmapped headwater streams, etc. Furthermore, the land disturbance nature of HVHF operations results in a dispersed industry across a wide area, with a large (and unknown) number of stream crossings and an increase in road traffic and gravel road construction. The documented water quality impacts of roads (including gravel roads) are also discussed in Attachment A.

Summary of Key Findings:

The RDSGEIS provides only a very brief generic discussion on the potential land disturbance and associated stormwater and water quality impacts on surface waters from HVHF (and well drilling in general). While the RDSGEIS acknowledges that this land disturbance has potential for water quality impacts, and the Department has made a positive determination that a SPDES permit is required, the RDSGEIS provides little specific discussion or consideration of the land disturbance and surface water quality impacts. Specifically:

- The RDSGEIS makes no attempt to evaluate the <u>cumulative</u> impacts of HVHF activity on water resources, at either the small (headwater stream) scale, or the larger watershed scale. Even very general cumulative estimates of land disturbance, and its associated water quality impacts, are not provided. Since the 1992 GEIS, the use of improved geographic information system (GIS) software and modeling tools has expanded the ability of scientists, engineers, and regulators to quantify the scale and impact of proposed activities on water resources. Such analysis has become standard industry practice for watershed planning and the development of TMDL (Total Daily Maximum Load) studies to determine the level of pollutant load (and required pollutant load reduction) to meet water quality standards. The RDSGEIS fails to provide any such analysis, and instead only acknowledges stormwater impacts with little industry-specific consideration, and no consideration of total or cumulative impacts. **A more detailed and comprehensive evaluation of the amount of anticipated land disturbance and associated water quality impacts is essential for a full environmental impact analysis, and to inform any determinations by the Department on the appropriate regulatory permitting requirements.**
- The RDSGEIS fails to consider the potential surface water impacts of stream crossing activity associated with HVHF well pads, most notably, stream

crossings associated with gathering lines and access roads (to both well pads and compressor stations). Stream crossings and the associated water quality impacts are not fully addressed in the RDSGEIS, and are specifically <u>not</u> included in the Draft SPDES HVHF GP. It is unclear how many stream crossings may be anticipated, and of these, how many will essentially be unregulated under current Department regulations. It is unclear what the anticipated environmental impacts of these stream crossings will be on water quality and aquatic systems. **The RDSGEIS should provide some estimate of the extent of anticipated stream crossings, potential water quality impacts, and proposed Department requirements to regulate and mitigate these impacts.**

- The RDSGEIS does not adequately address private well setbacks, road spreading of brine, gather lines, fueling areas, on-site disposal of drill cuttings, and acid rock drainage. Each of these has the potential to significantly impact and impair water quality. **The RDSGEIS should provide additional information regarding each of these impacts, specifically with regard to landowner notification of well setbacks, cumulative impacts of road spreading of brine, minimizing stream crossings with gather lines, addressing the non-stationary status of fueling areas, and consideration of ARD impacts from disposal of drill cuttings.**
- With the exception of watersheds that serve as unfiltered drinking water supplies and receive Filtration Avoidance Determination (FAD) status, the RDSGEIS and SPDES HVHF GP do not provide any specific consideration of whether different performance requirements or standards are necessary to protect water quality for higher quality watersheds, impaired streams, or areas of denser well pad development on a watershed basis. There is no documentation to support that proposed setbacks are adequate to protect water quality in all situations (i.e., higher quality streams, percent of land disturbance within a watershed, site specific conditions such as steep

slopes). **The RDSGEIS should provide some analysis or justification as to why a single set of performance requirements is applicable in all watersheds and all situations, regardless of stream designation or current levels of impairment or high quality.**

- Even if the proposed setbacks discussed in Chapter 7 were adequate, they are not clearly coordinated with the EAF requirements in Appendices 4, 5, 6 and 10 and the Draft SPDES HVHF GP mapping and documentation requirements (and the SPDES HVHF GP is presumably the regulatory mechanism for compliance). **The Draft SPDES HVHF GP mapping requirements must be at a scale and level of site-specific detail to accurately reflect the required information, and SPDES mapping requirements must be consistent with those identified in the RDSGEIS.**
- The RDSGEIS fails to provide a clear and accessible process for public and local government access to site specific HVHF activity information. At the same time, DEC expects local governments to provide notice to the Department if a proposed HVHF activity is not in compliance with local zoning or land use regulations. This approach puts the regulatory burden on a local government that wishes to challenge a proposed permit application while simultaneously failing to provide local government with access to the necessary information. **The burden of demonstrating compliance with local government land use requirements should fall on the industry, not local government and the public,** with supporting public access to all information regarding proposed land disturbance activity, and reasonable timeframes and processes for comments and addressing of concerns.
- The Draft SPDES HVHF GP is essentially a compilation of the Department's general permits for both construction activity and industrial activity. The general permit process is essentially "self-regulating," relying on the regulated industry to adhere to certain compliance requirements. Based on the very limited discussion of land disturbance and surface water impacts in the RDSGEIS, it is uncertain whether a general permit process will be

sufficient to protect water quality. It is also not clear that an industry that is NOT subject to local government review and approval, unlike virtually all other land disturbance activities addressed by general permits, can be adequately regulated through a general permit process. This is especially important for a heavy industrial activity that will be occurring in areas not zoned or accustomed to heavy industrial activity at the scale that will occur with HVHF operations.

- The general permit process does not provide a timeframe (and process) for public review, comment, and objection to any or all parts of a general permit coverage. Essentially, permit coverage is automatically granted to the industry by providing notice to the Department and meeting minimum performance requirements. There is no opportunity for public access to information or appeal of permit coverage. **It is essential that the SPDES HVHF GP provide a process for public access to all information associated with HVHF land disturbance and water quality impacts, and that a process and timeline be developed to allow for public comment and appeal of general permit coverage for a specific site *before* general permit coverage is granted. It is essential that the permit coverage timeline be adjusted to provide for public comment and appeal.**

Comments on the RDSGEIS

As previously indicated, the discussion in the RDSGEIS on the total land use impacts and associated water quality impacts as a result of both land disturbance during construction and post-construction stormwater management is extremely limited.

Comment 1:

Chapter 5, Natural Gas Development & High-Volume Hydraulic Fracturing. Section 5.1 of the RDSGEIS discusses the impacts of Land Disturbance, including Access Roads, Well Pads, Utility Corridors, and Well Pad Density. See pages 5-6 through 5-31. Estimates of land disturbance associated with each of these well drilling activities are provided but total or cumulative land disturbance is not addressed.

Comment 2:

Section 5.1 *Land Disturbance* identifies a number of types of land disturbance activities associated with HVHF including utility corridors (including gathering lines), compressor facilities, and access roads associated with compressor facilities. The Draft HVHF SPDES permit (Part III.A.3) does NOT address construction of gathering lines, compressor facilities, or the access roads associated with compressor facilities.

Recommendation: The RDSGEIS must provide a process for regulation and mitigation of the land disturbance impacts associated with gathering lines, compressor facilities, and the access roads associated with compressor facilities. The RDSGEIS cannot identify the SWPPP as "*the principal control mechanism to mitigate potential significant adverse impacts from stormwater runoff*" (Section 7.1.2 SGEIS) without providing for adequate management requirements for all HVHF activities in the Draft SPDES HVHF GP.

Further discussion in Section 5.1 provides some analysis of disturbance areas associated with gathering lines, compressor stations, and access roads to compressor stations, but specific consideration of the impacts of these activities is not discussed in Chapter 6, and specific recommendations to reduce the impacts of these components (such as co-locating gathering lines along well pad access roads) is not provided in Section 7 or the Draft HVHF SPDES permit.

Comment 3:

Section 5.1.1 *Access Roads* indicates that roads may be placed across ditches, but does not discuss the construction or widening of access roads that cross streams or wetlands. The potential impacts of such crossings are not discussed in Section 6.1.2, *Stormwater Runoff* or other portions of Section 6, nor are the mitigation measures for road crossings of streams and wetlands addressed in Section 7.1.2 *Stormwater.* Setbacks for roads from streams and wetlands are not specifically addressed in either Chapter 7 or the Draft HVHF SPDES permit, nor are requirements for stream and wetland crossings provided. It is not clear as to whether an Article 15 Stream Disturbance Permit from the DEC will be required for HVHF projects and what compliance might entail. It is noted that Photos 5.1 and 5.2 of the RDSGEIS portray access road stream crossings, but the impacts of the stream crossing are not addressed.

Road crossings of streams and wetlands will be unavoidable during the development of HVHF sites. Section 5.1.1 acknowledges that the length of road may be influenced by selecting a route to avoid environmentally sensitive areas, but mitigation measures recommending such route selection are not specifically addressed in either Chapter 7 or the Draft HVHF SPDES Permit. Estimates of the number and extent of anticipated stream and wetland crossings are not provided in Section 5.1.1.

Recommendation: The proximity of roads to streams and wetlands, and the unavoidable need to cross streams and wetlands, increases the risk that erosion and sedimentation will cause measurable impacts on water quality. Poorly constructed stream crossings can directly impact aquatic communities.[3, 7] Excessive sediment levels are one of the primary threats to US surface waters[10] and have multiple effects on stream health. The RDSGEIS should provide estimates of the anticipated extent of road crossings of streams and wetlands, as well as an evaluation of the potential environmental impacts of these crossings. Furthermore, avoidance and mitigation measures should be addressed in the RDSGEIS and incorporated into the regulatory process. Specific requirements and guidelines to mitigate the impacts of stream and wetland crossings should be provided.

Recommendation: If the SPDES HVHF GP is to be the primary mechanism for regulation, then the permit should include a defined documentation process to require the applicant to reduce the number and extent of stream crossings. This section should be incorporated into Part IV, *Contents of the Construction SWPPP*, as a requirement of Section A.1 and include both mapping requirements and narrative that documents the need for each stream crossing and explanation as to why any individual stream crossings cannot be reduced or combined. Road crossings on areas specifically in conflict with local government land use regulations should be identified, as well as road crossings on steep slopes erodible soils, or intact woodlands.

Comment 4:

Section 5.1.2 *Well Pads* notes that well pad size is determined by site topography, but no estimates are provided regarding the impact of slope on well pad size and disturbance footprint, and the increased impacts on erosion and sediment discharge. The area of disturbance can be increased by up to 50% on slopes exceeding 15 degrees[8] (the Draft HVHF SPDES permit allows disturbance on slopes up to 25% in AA or AA-s watersheds. It is not clear that there is a limit on slope construction in other watersheds). The stormwater and erosive impacts of well pads on steep slopes continues through the life of the well pad. At a minimum, the Draft SPDES HVHF GP should preclude well pad construction on slopes over 25%.

<u>Recommendation:</u> Section 5.1.2 should provide some evaluation of the anticipated increase in well pad disturbance as a function of slope (and required cut and fill) as a result of the impacted terrain conditions specific to New York. Section 7 of the RDSGEIS should provide discussion of specific mitigation measures to reduce the impacts of well pad construction on slopes. The HVHF SPDES permit should include specific requirements to reduce construction of well pads on steep slopes, limits on steep slope construction in all watersheds, and provide discussion and requirement of implementation measures to reduce the long-term water quality impact of well pads on slopes when such systems are constructed. Additional measures to prevent sediment discharge from construction on steep slopes should be defined and required as part of the facility SWPPP. It is not clear that the general requirements of either the 2005 New York State Standards and Specifications for Erosion Control or the 2010 New York State Stormwater Management Design Manual provide sufficient specific guidance to address the additional impacts associated with well pad construction on slopes. Both erosion control measures and stormwater measures must be adjusted in their design to account for the greater water quality impacts of well pad location on slopes.

<u>Comment 5:</u>

Section 5.1.2 *Well Pads* and **Section 5.1.4** *Well Pad Density* do not provide any specific information or estimates of well pad or HVHF facility location or density with regards to watershed drainage areas, or analysis of the anticipated density of well pads within intermittent or perennial headwater stream drainage areas. Section 6 does not discuss the impacts on water quality of well pad density within the drainage area of an intermittent or perennial stream. Headwater and intermittent perennial streams originate with a drainage area of 5.5- to 37-acres[5], increasing the likelihood of a HVHF well pad being within several hundred feet of an intermittent or perennial stream, and the likelihood that the disturbance will represent a sizable portion of the total drainage area to a headwater stream (i.e. 7.4 acres of total disturbance for a multi-well pad during the drilling phase, and 1.5

acres of disturbance during the drilling phase could represent a very large percentage of the drainage area of a headwater or small stream).

Recommendation: Current research[2] indicates a positive relationship between stream water turbidity and well density within a drainage area or watershed. The RDSGEIS does not provide any analysis or consideration of potential levels of watershed disturbance as a result of HVHF activities, and the resulting potential impacts on water quality, although such an analysis is well within current mapping and GIS capabilities and should be included in the RDSGEIS.

Comment 6:

While some mention of gathering lines is included in **Section 5.1.3** *Utility Corridors*, including an estimate of 1.66 acres per well pad, no discussion is made of the anticipated extent of stream crossings, or the cumulative levels of land disturbance associated with gathering lines on a watershed or other basis. No further discussion is provided in Chapters 6 and 7 specific to gathering lines. It is unclear exactly how the current DEC permit process for pipeline stream crossing is adequate to protect water quality from either a land disturbance or stream crossing impact from gathering lines, or how gathering line construction will be addressed and/or coordinated with the Draft HVHF SPDES permit process (which does not currently address gathering lines).

Recommendation: This issue requires additional consideration in the RDSGEIS, and the specific permitting requirements for gathering line stream crossings should either be identified in the Draft HVHF SPDES permit or coordinated with this permit so that impacts are reduced. Specifically, measures to reduce the impact of gathering line stream crossings (and general construction) by coordination of this construction with other well site needs should be required.

Comment 7:

Chapter 6, Potential Environmental Impacts. Section 6.1.2 *Stormwater Runoff,* discusses both stormwater impacts and erosion and sedimentation construction issues. However, this discussion is very general in nature, comprising only 1-1/4 pages within Chapter 6 for both of these topics. No discussion is provided regarding the specific magnitude and issues of concern associated with stormwater and erosion impacts from the various HVHF activities (i.e. well pad construction, and variations on well pad construction such as disturbance footprint from construction on steep slopes). Rather, it is simply noted that the potential for water resource impacts exists, and that these impacts may cause increased runoff volumes, greater erosive forces, heightened sediment loads, etc.

Recommendation: Research data and engineering methodologies are available to quantify the potential adverse water quality impacts, either on a "typical" facility basis or an anticipated watershed basis (using the estimates of acreage developed in Section 5). Such analysis would provide at least some basis for determining whether the requirements of the Draft HVHF SPDES GP are adequate for the industry. These estimates would also provide information on the cumulative impacts of HVHF on water quality and stream health and should be included in the RDSGEIS.

Comment 8:

Chapter 7, Mitigation Measures. Section 7.1.2 *Stormwater,* discusses stormwater management in general terms, with a non-specific discussion of the particular issues associated with HVHF stormwater and erosion. Much of the generic discussion focuses on pollution prevention from exposed industrial activities. Less than one page addresses stormwater management mitigation measures related to land use changes, and one-half page addresses mitigation associated with stormwater and erosion issues from construction activities. Section 7.1.3 discusses spills and containment, which is also addressed in the SPDES HVHF GP. However, much of this discussion is focused on industrial spill control, not stormwater impacts.

Chapter 7 indicates that the Department intends to issue a single SPDES General Permit that will encompass all issues of construction stormwater and erosion control, post-construction stormwater management, industrial stormwater management, and pollution prevention/spill control. Specifically, page 7-26 states: *The Department has determined that natural gas well development using high-volume hydraulic fracturing would require a SPDES permit to address stormwater runoff, erosion, and sedimentation. The SPDES permit will address the construction of well pads and access roads and any associated soil disturbance, as well as provisions to address surface activities associated with high-volume hydraulic fracturing for natural gas development. Additionally, during production of the natural gas, the Department will require coverage under the SPDES permit to remain in effect and/or compliance with regulations. The Department proposes to require SPDES permit conditions, a Comprehensive SWPPP (stormwater pollution prevention plan), and both structural and non-structural Best Management Practices (BMPs) to minimize or eliminate pollutants in stormwater. The Department is proposing the use of a SPDES general permit for high-volume hydraulic fracturing (HVHF GP), but the Department proposes to use the same requirements in other SPDES permits should the HVHF GP not be issued.*

Recommendation: The HVHF SPDES permit should be specific to this industry and impose requirements that reflect the lack of local government review and approval of the land development activities associated with the industry. The RDSGEIS should specifically identify the areas where additional permit requirements specific to the industry are necessary to protect water resources.

Comment 9:

Section 5.1.1 *Access Roads* notes that roads may be constructed by placing crushed stone or gravel, but Section 6 does not specifically address the water quality issues associated with the long-term use of gravel roads (after construction), nor does Section 6 provide any estimate of potential pollutant loadings associated with gravel roads, specifically estimates of sediment generation. Research data[4] indicates that gravel roads can be a significant source of sediment pollution, and data to support sediment pollutant load estimates is available but requires an estimate of the anticipated extent and area of gravel access roads to be constructed, which is not provided in Section 5.1.1. Gravel access roads serving HVHF will be subject to undefined levels of truck traffic, which has a greater impact on road condition and erosion than regular vehicle traffic. Section 6.1.2 *Stormwater Runoff* discusses the impacts of sediment on streams and notes that "*steep access roads…pose particular challenges.*" **Section 7.1.2** *Stormwater* indicates that the construction of access roads will be addressed by the SPDES permit, but neither Section 7.1.2 nor the Draft HVHF SPDES permit provide specific recommendations to reduce the length and width of gravel access roads, to reduce construction access roads on steep slopes, or to reduce the specific impacts of gravel road and sediment generation once the construction period has ended. General reference to the State stormwater manual is not sufficient for this issue as it relates to HVHF. There is no requirement in the Draft HVHF SPDES mapping requirements to indicate or accurately depict the length, width, or slope of gravel access roads. Since these areas will generate sediment pollutants through the life of the project, specific guidelines to mitigate pollution from access roads are warranted.

Recommendation: The RDSGIES should provide more detailed information on the specific impacts of gravel access roads with regards to sediment generation, and the estimated extent of potential pollutant loads. Section 7 of the RDSGEIS should provide discussion of specific mitigation measures to reduce the impacts of access road construction. The HVHF SPDES permit should indicate specific requirements for the documentation of access road lengths and widths, and requirements to reduce construction on steep slopes, reduce road width, and implement other measures to reduce the water quality impact of access roads.   Measures to maintain gravel access roads in a manner that prevents sediment discharge (over the life of the project) should be defined and required as part of the facility SWPPP.

<u>Comment 10:</u>

Section 7.1.11.1 *Setback from private well*, Section 7.1.11.1 states that "The Department proposes that it will not issue permits for high-volume hydraulic fracturing within 500 feet of a private water well or domestic supply spring unless waived by the landowner." However, the Draft SPDES permit does not require the applicant to map the location of private water wells or springs that may be within 500 feet, or to notify the landowner. Coverage under the GP is granted within 30 calendar days of the Department receiving the NOI (and meeting the requirements of Part II.B.2). How will the Department or the applicant be aware of the existence of private water wells within 500 feet? This is also not included in Section 5 of the Environmental Assessment Form, but IS included in the Proposed EAF Addendum Requirements for HVHF. It is not clear how 500 feet was determined as sufficient distance to support a private well from HVHF activities as no supportive reasoning is provided.

<u>Recommendation</u>: Require that all private water wells and domestic supply springs within 2,640 feet and 500 feet, respectively, to be located on the Site Map (prepared under Part IV.C.1.b and as a requirement to the Site Map in the SWPPP). The NOI form should require that the applicant confirm that there are no such wells within 500 feet, and provide proof to the Department of landowner waiver receipt (by certified mail or similar means).

<u>Recommendation</u>: The SWPPP should identify the private water well or spring in the narrative (Part XI.3) and identify measures undertaken to protect the private well and to address emergency spill situations.

<u>Comment 11:</u>

Section 7.1.11.2 *Setbacks from Other Surface Water Resources* states *"*Existing regulations prohibit the surface location of an oil or gas well within 50 feet of any 'public stream, river or other body of water.'" The 1992 GEIS proposed that this distance be increased to 150 feet and apply to the <u>entire well site</u> instead of just the well itself*".* The Draft HVHF SPDES permit (Section I.D.4) requires a setback of 150 feet from the <u>well pad</u> and perennial or intermittent streams, but does not address setbacks from other HVHF site components.

<u>Recommendation:</u> As discussed later in specific recommendations associated with the Draft HVHF SPDES permit, required setbacks of any length are meaningless unless the water features are accurately identified and located. A USGS 7-1/2 minute topographic map, at a scale of 1" = 2000' is inadequate for this purpose. It is essential that the Draft HVHF SPDES permit require mapping at a scale that can accurately depict both existing natural features (such as steep slopes and headwater streams) as well as proposed HVHF components.

<u>Comment 12:</u>

There are benefits associated with a single SPDES GP (or a single individual SPDES permit) that addresses construction, post-construction stormwater, and industrial stormwater and spill containment for each project in one permit. These benefits include a comprehensive evaluation of each project, potential continuity in responsible facility personnel, and consistency of management practices through both construction and operation.

However, the Department is largely drawing on the current requirements in the existing SPDES general permit for construction (New York State Department of Environmental Conservation SPDES General Permit For Stormwater Discharges From Construction Activity Permit No. GP-0-10-001) and the existing SPDES general permit for industry (New York State Department of Environmental Conservation SPDES Multi-Sector General Permit For Stormwater Discharges Associated With

Industrial Activity Permit No. GP-0-06-002). The Department is combining many (but not all) requirements of these two GPs into one HVHF GP and, in doing so, does not include provisions that would otherwise be required of permittees seeking either of the existing permits alone..

For the issues of site disturbance, stormwater management, setbacks, disturbance of sensitive features, erosion, and other impacts associated with many non-HVHF land development projects and industrial activities, there is an additional level of professional review and regulation in the form of local laws, regulations, plans or policies implemented by the local planning board or authorized board. In other words, for non-HVHF projects, such as land development projects, there is often a local project review of proposed plans by a professional reviewer knowledgeable in local conditions, supported by the review of an authorized board whose members possess local knowledge. Local regulations are likely to impose more rigorous mapping requirements, stormwater calculations, and design detail than those imposed in a Department general permit, and furthermore, project submissions receive local, professional review. In these circumstances, successful design and compliance (with the requirements of Department general permit) is more likely when supported by a secondary level of performance requirements and review at the local level.

The issuance of a single GP for HVHF (that encompasses many requirements of both existing Department GPs) will not have the benefit of local review and specific local performance requirements. The potential impacts of HVHF projects on land disturbance, stormwater, erosion, sensitive sites, etc. is at least as significant (if not more significant) than other, locally regulated land disturbance and industrial activities. HVHF is also a "heavy" industry that will be located in many areas unaccustomed to heavy industry.

Recommendation: The Department should provide the opportunity for local review by revising the SPDES HVHF GP to address compliance with applicable local ordinances. For instance, those activities which would typically require issuance of

GP-0-10-001 should be required to comply with all local ordinance requirements as they apply to HVHF activities. Additionally, the Department should require SPDES HVHF GP permittees to provide written notification to the Department from the affected local governments that the conditions of local ordinances are met to the satisfaction of the local governing authority prior to issuance of the permit. Comment 14 below discusses this further.

Comment 13:

HVHF compliance with the requirements of the GP are largely self-reviewing and self-monitoring, as facilities are required to develop and implement a SWPPP, but there is generally no review of the SWPPP unless the Department elects to request and review the SWPPP for a specific facility. Absent this specific request by DEC, the SWPPP is simply maintained on-site. In addition, DEC does not propose any mechanism that would enable it to effectively evaluate successful implantation of a SWPPP.

Recommendation: The SPDES HVHF GP should be revised to make public all documents, specifically including the SWPPP, available for review by the Department and the public. In all instances, the Department should establish a mechanism to routinely review whether applicants have successfully implemented their SWPPPs. Dated digital photos that support inspection and compliance per permit and SWPP requirements should be a requirement for permit coverage.

Comment 14:

Chapter 8 , Permit Process and Regulatory Coordination; **Section 8.1.1.5** *Local Planning Documents* of the SGEIS states:

> *However, in order to consider potential significant adverse impacts on land use and zoning as required by SEQRA, the EAF Addendum would require the applicant to identify whether the proposed location of the well pad, or any*

> *other activity under the jurisdiction of the Department, conflicts with local land use laws or regulations, plans or policies. The applicant would also be required to identify whether the well pad is located in an area where the affected community has adopted a comprehensive plan or other local land use plan and whether the proposed action is inconsistent with such plan(s). For actions where the applicant indicates to the Department that the location of the well pad, or any other activity under the jurisdiction of the Department, is either consistent with local land use laws, regulations, plans or policies, or is not covered by such local land use laws, regulations, plans or policies, the Department would proceed to permit issuance unless it receives notice of an asserted conflict by the potentially impacted local government.*

This approach is problematic. While it is the responsibility of the applicant to determine whether or not there are any conflicts, it is up to the potentially impacted local government to provide notice to the Department of an asserted conflict that has not been identified by the applicant. Although the RDSGEIS states that the Department would notify local governments of all applications for high-volume hydraulic fracturing in the locality, through the use of an electronic notification system to local government officials (see DSGEIS at 8-4), DEC offers no guarantee that this system will be in place prior to the issuance of permits and does not specifically describe when in the permitting process such notification to local governments will occur. These are critical issues that should be addressed. Further, it is unclear how the Department will determine "*whether significant adverse environmental impacts would result from the proposed project that have not been addressed in the SGEIS and whether additional mitigation or other action should be taken in light of such significant adverse impacts." RDSGEIS at 8-5.* It is also not clear as to whether this determination process applies to all HVHF GP applicants, or only those subject to SEQRA determination.

<u>Recommendation</u>: In consideration of the Department's decision to regulate HVHF under a single SPDES general permit <u>without</u> the important supplemental benefit of local review and local laws, regulations, plans or policies (that virtually all other land development and industrial construction projects are subject to when obtaining SPDES permit coverage), obtaining General or Individual Permit coverage (for all HVHF projects) should also require the applicant to notify the local government (as well as the Department) that there are no conflicts with local laws, regulations, plans or policies, and to provide supporting documentation of the evaluation to the local government and Department. This will allow local governments to receive the necessary information to "assert" a potential conflict that may not have been identified by the applicant. Without this critical information, local governments cannot be expected to "assert" a potential conflict to the Department.

Comment 15:

As discussed above, Section 5.1 of the RDSGEIS provides estimates of land disturbance for well pads and associated construction activities (roads, utility corridors, compressors, etc.), including total estimated disturbance per pad for multi- and single-well pads. The RDSGEIS notes that most wells will be multi-pad wells with a net disturbance of 7.4 acres per pad (reducing to 1.5 acres per pad during production). A spacing of 640 acres per multi-well pad is presented in Table 5.1 of the RDSGEIS. However, no consideration is provided of the anticipated disturbance and well pad density on a watershed basis, or proximity to streams and anticipated stream crossings, and no consideration is provided on the potential individual and cumulative effects on stream health.

A recently published study of natural gas development in the Fayetteville and Marcellus formations in Arkansas and Pennsylvania[2] used current topographic data, well development data, and readily available land use analysis computer modeling tools (ArcHydro Version 1.3) to evaluate both the overall well pad density per drainage area and well proximity to streams in these formations in Arkansas and Pennsylvania. This desktop analysis was further supported by in-stream turbidity measurements in seven different drainage areas with different well densities.

This report had several significant findings, most notably it "identified a positive relationship between stream water turbidity and well density. Turbidity was not positively correlated to other land use cover variables." (Entrekin, et al, "Rapid Expansion of Natural Gas Development Poses a Threat to Surface Waters, pg 507). The report further concluded that "preliminary data suggest that the cumulative effects from gas well and associated infrastructure development are detectable at the landscape scale."

This study also determined that approximately 17% of the active Pennsylvania wells were within 100 meters (328 feet) of a stream, and all wells were within 300 meters (984 feet) of a stream. Gas wells "were located, on average, 15 km (9.3 miles) from public surface-water drinking supplies and 37 km (23 miles) from public well water supplies." The report noted that "although wells are generally constructed far from public drinking-water sources, there is potential for wastewater to travel long distances given that many of the components, such as brines, will not settle out or be assimilated into biomass." In other words, due to the nature of material from HVHF wells, discharges that reach streams (due to inadequate stream setbacks) may travel to public drinking supplies, even if the surface water supplies are distant to the well.

Chapter 6 of the RDSGEIS broadly identifies potential environmental impacts on water resources (Section 6.1), including polluted stormwater runoff and spills. The RDSGEIS does not specifically discuss the cumulative impacts of land disturbance on surface water quality (i.e. whether turbidity or other measures of stream impact increase with well density). The RDSGEIS makes no attempt to estimate well density and land disturbance on a drainage area basis with regards to water quality impacts or consideration of specific watersheds and designated uses. No specific consideration is given to the topography and stream density of New York State with regards to land disturbance and proximity to surface waters.

Such an analysis would provide a far better estimate of potential surface water impacts and the extent of anticipated land disturbance on a watershed or drainage area basis. This information would inform the state as to the watershed impacts from HVHF activities, and provide some additional basis for well density in different watersheds. It would also better inform the decisions regarding setback distances discussed in Sections 7.1.5 and 7.1.11.2.

As discussed previously, most headwater and small perennial streams are not indicated on USGS 7-1/2 minute topographic quadrangles, and hence will not necessarily be identified under the current mapping requirements in the Draft HVHF SPDES permit. Headwater streams generally originate with a surface drainage area of 5 to 37 acres.[5] The study discussed above had a stream threshold of 12.4 acres. With a disturbance footprint of 7.4 acres per multi-well pad, drilling activities could potentially impact as much as 60% of the land area in a headwater stream drainage area (assuming 12.4 acres per drainage area). The extent and impact of land disturbance in headwater streams is not addressed in any manner in the RDSGEIS.

Recommendation: The RDSGEIS should provide some technically supported evaluation of the anticipated well density on a drainage area basis, with consideration of water quality impacts. The analytical land use tools, data, and models available today are significantly more robust than the environmental tools available during the development of the 1992 GEIS (and such tools are often used to support TMDL determinations). In other words, the density of anticipated land disturbance and proximity to streams and wetlands could easily be mapped and evaluated using anticipated development rates and relevant information from states such as Pennsylvania. At a minimum, representative watersheds could be evaluated in detail to represent anticipated conditions, and using topographic data and average proximity to streams could be estimated. Relevant well drilling data is also available from other states such as Pennsylvania. High-volume hydraulic fracturing is "distinct from other types of well completion" as noted in the RDSGEIS, and warrants additional consideration.

This type of land use and density evaluation will allow the Department to better assess the potential impacts of high-volume hydraulic fracturing on both watershed land use and proximity to streams, and can provide a technical basis for HVHF well density and setback decisions. It can also inform decisions regarding well density and setbacks in waters with TMDLs. But at this time there is no watershed impact consideration of HVHF well location and density. It is unclear whether the various setbacks discussed in the RDSGEIS are adequate to protect water resources during HVHF activity, or whether these setbacks merely represent an arbitrarily selected value.

Recommendation: To facilitate Department identification of wells that may have an impact on small headwater streams, the Draft SPDES HVHF GP could require that each well pad application document the total amount of anticipated land disturbance, and the percent of land disturbance within the drainage area of the well pad location. This is not a difficult estimate for the permit applicant to develop using current mapping tools, and will provide some indication that adjacent streams may be small and especially vulnerable to land use impacts.

Comment 16:

Section 7.1.3.1 indicates that fueling tanks are considered "non-stationary" at well pads, and therefore exempt from Department storage and registration requirements. Section 7.1.3.1 does state that secondary containment is required for all fueling tanks, and that fueling tanks would not be positioned within 500 feet of perennial or intermittent stream, storm drain, wetland, lake or pond.

It is unclear how this requirement will be met or maintained, especially in light of the fueling tanks being "non-stationary." Specific requirements are not reflected in the Draft HVHF SPDES permit, either in the general SWPPP requirements or the Fueling Area requirements. It is unclear how this setback will be identified and maintained, and how the Department intends to ensure compliance. The requirements for fueling areas in the Draft HVHF SPDES permit are the same general requirements applied to all industrial facilities and do not have any specific consideration of the nature and conditions of HVHF sites and fueling needs.

<u>Recommendation:</u> The RDSGEIS and Draft HVHF SPDES permit must address the issue of containment for "non-stationary" fueling tanks, and all other non-stationary tanks.

<u>Comment 17:</u>

The RDSGEIS **Section 7.1.7.2 Road Spreading** indicates that NORM concentration data in brines is insufficient to allow road spreading under a BUD, and that as more data becomes available the Department will evaluate the BUD petitions. However, the RDSGEIS is inadequate in that no consideration has been made of the total potential increase in chlorides on roads as a result of the HVHF industry disposing of brines in this manner, and the anticipated levels of chlorides and other compounds in the brine. Again, the RDSGEIS has not considered the cumulative impacts of the generation of this material and the potential volume of material application on roadways. No estimate is made of the volume of production brine that may be disposed of on roadways. No consideration is provided regarding what might be "safe" levels of chlorides (or other compounds) in different situations, or what other additional compounds that may be found in production brine that would preclude the use of the material for roadway application. The requirements in the current BUD have no basis as being sufficient for protecting water quality, and are generally self-monitored by the industry.

Unless the use of production brine is demonstrated as being a beneficial use for the public in roadway safety, application to roadways should not be seen as a viable disposal method. Much more research on the effects of the material on plant and aquatic systems is required.

Recommendation: The RDSGEIS should provide better information regarding anticipated brine production levels and disposal needs as a result of HVHF activity. Future authorization of the application of brines under a BUD should not be allowed until this information has been developed and provided for public review and comment.

Comment 18:

Section 7.1.9 Solids Disposal indicates that the generation of acid rock drainage (ARD) may occur as the result of material from certain portions of the Marcellus shale. The RDSGEIS indicates that an ARD mitigation plan would be required for in-site burial, but is not required for off-site disposal.

No estimate is provided within the RDSGEIS of the potential amount or magnitude of the generation of this material, and whether or not the amount of ARD material is of concern, or within which watersheds such material may be anticipated. The generation of ARD is of significant concern and impact on watershed health, and warrants more detailed analysis of the anticipated locations and extent where ARD may be an issue. It is not clear if this is expected to be an extensive concern, and no consideration is made of the amount and extent of the ARD material encountered in other states such as Pennsylvania, and how much this material has created additional acid discharge problems in other states. This issue is not addressed in the HVHF SPDES draft permit.

Recommendation: Estimates of the anticipated extent of such material should be included in Chapter 6.1.9.2, and coordinated requirements for ARD treatment (as discussed in Section 7) incorporated into the Draft HVHF SPDES permit. This material has significant potential impact to water quality.

Comment 19:

The EAF addendum should clearly define the process and timeline for notification of local government, and for the Department's process for determination of permit applicability when notice is received from the applicant or local governments that a conflict with local laws, regulations, plans or policies exists. Furthermore, the EAF addendum should address the issue of HVHF GP coverage upon NOI submission when such local conflicts exist.

<u>Recommendation:</u> Coverage should NOT begin until proof of notification to local governments has been received by the Department, local governments have been provided sufficient information and time to "assert" any unidentified potential conflicts, and the Department has made project specific determinations regarding the impact of identified or asserted conflicts. A timeline and process must be defined.

<u>Comment 20:</u>

EAF Appendix 12 Beneficial Use Determination (BUD) Notification Regarding Road Spreading states that "Any person, including any government entity, applying for a Part 364 permit or permit modification to use production brine from oil or gas wells or brine from LPG well storage operations for road spreading purposes (i.e. road deicing, dust suppression, or road stabilization) must submit a petition for a beneficial use determination (BUD)." This petition must include sampling data (although the sampling parameters are limited), a map indicating roads where brine is to be spread, and a general narrative of practices to be implemented, including avoiding applying brines within 50 feet of a stream or waterbody, avoiding application during rainfall periods or on slopes greater than 10 percent.

Chlorides are toxic to many plants and freshwater aquatic plants and invertebrates[14] with levels as low as 30 mg/L toxic to plants, and at 1000 mg/L toxic to aquatic plants and invertebrates. Chlorides also impact the use of surface water for potable water sources.

While chlorides are applied to roads during snow and ice conditions for safety reasons, many state Departments of Transportation have begun programs to significantly reduce the use of chlorides and implement alternative de-icing practices to reduce the impacts of chloride on both vegetation and stream system health.

Recommendation: Additional analysis of potential impacts must be done to evaluate potential impacts from road spreading, including analysis to support that the proposed setback criteria are sufficient to protect water quality, as well as to define required sampling requirements for BUD petitions.

Comment 21:

In addition to defining the processes and timelines for review and notification requirements, coordinating permit approvals and public participation activities would ensure compliance with all applicable statutes and eliminate any conflicts that may arise. Regulatory permit tracking, municipal coordination and public outreach and participation should be integrated and automated to the fullest extent possible to ensure satisfactory oversight of gas development operations. This includes the use of internet and GIS technologies for geovisualization, database management, and compliance with all regulatory requirements.

One example of internet-based GIS information sharing is the Pennsylvania Department of Environmental Protection's (PA DEP) eMapPA website. PA DEP uses this online application that is updated on a regular schedule and tied to a multitude of databases which track publicly available information (air quality, water quality, mining/reclamation, natural resources, etc.) on a publicly accessible GIS website. (See http://www.emappa.dep.state.pa.us/emappa/viewer.htm).

Recommendation: With regard to regulatory permit tracking, PA DEP has developed an additional tool called Environment, Facility, Application, Compliance Tracking System (eFACTS). PA DEP staff, as necessary, has internal agency access to this database system, cross-referenced by regulatory program, in which permits and permittees may be tracked and updated with regard to permits issued, violations, etc. This information is also available to the public, in a limited format, via the internet at http://www.dep.state.pa.us/dep/efacts/efacts.html. If not already available through the NYS Department Application Review Tracking (DART) system, the development of such a system would be very beneficial for tracking SPDES

HVHF GPs, as well as other state issued permits associated with gas development projects, including dirt/gravel roads, stream crossings, etc. This information should be linked to any web-based GIS application.

Recommendation: Population of a geodatabase may occur through the submission of GIS data by permittees. Permit application packages could and should be front loaded for digital information by requiring permittees to submit GIS data (i.e., shapefiles in an accepted Metadata format) about their project sites. At a minimum, a project boundary on georeferenced state plane coordinate system should be required. This website should also link each project boundary to any online permit tracking system, including the email address of appropriate personnel to whom comments may be submitted.

Recommendation: In addition to sharing GIS data with local governments, NYSDEC should, if it has not already, implement a requirement for municipal notification similar to those commonly referred to in Pennsylvania as Act 14 notices. Pennsylvania permitting processes include requirements for written notifications to be sent to each municipality and county government in which the permitted facility is or will be located under an amendment to the Commonwealth's Administrative Code. These notifications allow 30 days for specific municipal and county comments.

Recommendation: Additional public participation may be solicited by the publication of notices of pending permits in NYSDEC's Environmental Notice Bulletin (ENB). Certain SPDES permitting actions are already included in the monthly ENB; however, it may be beneficial to provide a section specific to those SPDES permits issued for HVHF gas development on the ENB website and linked to the DART system.

Comments on the Draft SPDES HVHF GP

Impacts to surface water quality from gas exploration and extraction activities can occur during the construction of the facility, the operation of the facility, and as a result of inadequate restoration of the facility after operations have ceased. Applying specific performance standards and consistent regulatory oversight through a thorough permitting process is essential to ensuring the prevention of water quality impacts. A comprehensive permitting process should include, but not be limited to, the following considerations:

- Clearly defined permitting process and timelines;
- Sound technical guidelines specific to the activities being permitted;
- Compliance with both State and local regulations prior to final permit approvals;
- Opportunities for public participation, outreach, and comment.

These considerations, as well as a comprehensive evaluation of all potential environmental impacts, are essential to the development of permitting procedures that are adequately protective of environmental resources.

The RDSGEIS notes that certain water resources, such as the New York City and Syracuse drinking water supplies, have been the subject of extensive comment and warrant different regulatory requirements (i.e. a prohibition on drilling). Specifically, the "Department finds that standard stormwater control and other mitigation measures would not fully mitigate the risk of potential significant adverse impacts on water resources from high-volume hydraulic fracturing." RDSGEIS at 7-55.

In a paper prepared by Patrick O'Dell, a professional engineer with the National Park Service Geologic Resources Division, Mr. O'Dell noted that "If the public depends on operators in general to voluntarily use measures such as 'best management practices' to meet an agency's standards of resource protection, the public will be disappointed. This is because operators are sometimes willing to assume more environmental risk in exchange for a reduction in expense or acceleration of project completion."[8]

Given these comments, and that the Department recognizes that "*standard stormwater control and other mitigation measures would not fully mitigate the risk of potential significant adverse impacts on water resources from high-volume hydraulic fracturing*," and the Department's decision to preclude HVHF in FAD watersheds (Section 7.1.5), the validity and effectiveness of a self-monitoring GP process for other watersheds cannot be assumed to be protective of water resources, and the SPDES permit and associated regulatory activities must be developed to address these concerns.

In comments provided to the Pennsylvania DEP, Dr. James Schmid[14] PhD made the following recommendations that are directly applicable to NYSDEC regarding the HVHF SPDES permitting process in New York:

a. Place all gas-related permit applications, issued permits, and enforcement actions online in an electronic database accessible by public.
b. Include stream encroachment for pipelines *(in the SPDES permit).*
c. Select a significant number of permit applications for file and on-site audit, to ascertain trends in adequacy of permitting process.
d. Disallow general permits in Exceptional Value and High Quality waters (or in New York, require individual permits for AA or A drinking water streams and T or TS trout streams).
e. Require an inventory for all EV or HQ streams within 500 ft of well pads.

f. Make an attained use determination at every stream proposed for impact that has not been studied.
g. Require disclosure of ALL related facilities in each project application, require disclosure of all land and water disturbances for each well or well pad so that projects do not incorrectly fall below thresholds.
h. Require construction of impermeable holding areas sufficient to contain spills and prevent release outside pad.
i. Require accounting of tree clearing. Provide plans and timetable for reforestation.
j. Gathering lines and water pipelines should follow existing roads rather than new ROWs. New ROWs should be demonstrated to reduce stream/wetland crossings.
k. Distinguish between new stream crossings and those made atop existing culverts.

With these and other previously discussed recommendations in consideration, the following comments are provided with regards to the current Draft HVHF SPDES General Permit:

<u>Comment 1:</u> The Draft HVHF SPDES permit is primarily a compilation of the existing Construction SPDES GP (001) and the Industrial Stormwater GP (002). It has not been significantly modified to address the issues specific to HVHF. Additionally, the Draft HVHF SPDES permit should encompass ALL components of a well project (well pads, access roads, water lines, gathering lines, compressor stations, water withdrawals, transportation of materials, waste management) with considerations specific to HVHF, or clearly provided coordination with other permitting requirements specific to these issues.

<u>Comment2:</u> Given the lack of local land use review, the mapping and data requirements for the SWPPP should be coordinated with the mapping/data requirements of the Environmental Assessment Form, and <u>all</u> information should be available digitally for access by local government, property owners, and the general public. The RDSGEIS Appendix 5 *Environmental Assessment Form Attachment to Drilling Permit Application* does NOT reflect all site data requirements described in Appendix 6 *Proposed EAF Addendum Requirements for High-Volume Hydraulic Fracturing*.

<u>Comment3:</u> The SPDES HVHF GP should be modified to include construction and stormwater discharges related to gathering lines, compressor stations and compressor station access roads, or to clarify how these activities will be addressed under another permit.

<u>Comment 4:</u> In the absence of more explicit requirements, such as the submission of supporting calculations for BMP design, owners/operators are likely to use a generic narrative for multiple wells, with exception of mapping requirements. It is important that the SPDES HVHF GP requirements for mapping be site specific, comprehensive, at a scale that provides info needed. Generic SWPPPs tend to be ignored.

The following comments are in regard to specific sections of the Draft SPDES HVHF GP as noted.

Part I GENERAL PERMIT COVERAGE AND LIMITATIONS

<u>Comment 5:</u>

Section B.2 Maintaining Water Quality – This section places the burden of identifying a violation of a water quality standard on the Department, as opposed to the permittee. In the Industrial Stormwater GP, the burden of identifying such stormwater discharges is placed on the permittee: "*If there is evidence indicating* *that the stormwater discharges authorized by this permit are causing, have the reasonable potential to cause, or are contributing to an excursion above an applicable water quality standard, the permittee must take appropriate corrective action and notify DEC of corrective actions taken*." Similar responsibility should be placed on the permittee for HVHF activities.

Comment 6:

Section C.3 Non-Stormwater Discharges – This section authorizes non-stormwater discharges and adds "uncontaminated discharges from well site dewatering operations" to the list of allowable non-storm discharges. Is this section referring to only de-watering of erosion and sediment control measures in site development or to well drilling material? This should be clarified.

Comment 7:

Section D.2 Activities Which are Ineligible for Coverage under this General Permit – This section precludes the construction of HVHF only on locations where the stream designation is AA or AA-s, **and** there is no impervious cover **and** the slopes are greater than 25% or E / F slope designation. Does this mean that if there is some impervious cover on such a site that HVHF is allowed? Does this mean that all other sites have no limits on slope (unless identified by the applicant as addressed in local land use regulations **and** identified as an objection by local government)? Is disturbance of steep slopes allowed in T streams? Should steep slope disturbance be precluded in proximity to water bodies and wells and identified in setbacks? The RDSGEIS notes in Section 6.1.2 that "*Steep access roads, well pads on hill slopes, and well pads constructed by cut-and-fill operations pose particular challenges, especially if an on-site drilling pad is proposed."* This section should be substantially re-evaluated to preclude or define limits on coverage for steep slopes, etc. in all watersheds. Additionally, the Department should develop specific performance parameters/requirements for coverage of such activities on steep slopes under an Individual Permit for sites not addressed under the GP, rather than issuing an Individual Permit that is substantially similar to the GP. Additionally, this section should clarify that local land use regulations regarding steep slopes and other environmental constraints apply unless waived by local government.

Comment 8:

Section D.4 Setbacks for Well Pad – These setbacks should reflect further consideration in the RDSGEIS, and include all setbacks discussed and identified in the RDSGEIS and appendices – such as setbacks from private water supply wells and springs, public water supply wells, residences, etc. This section should also clarify where ALL HVHF activities are prohibited (i.e. within 100-year floodplain, within 4,000 feet of unfiltered water supply watersheds, within 2,000 feet of public water supply, etc.).

All setback dimensions should be indicated on the GP mapping requirements.

Additionally, this section should clarify that local land use regulation setbacks also apply unless waived by local government. The permittee should prepare documentation that such land use regulations have been evaluated, and the local government notified if local land use requirements have not been met.

Part II Obtaining General Permit Coverage

Comment 9:

A. Notice of Intent (NOI) Submittal – The applicant is required to submit an NOI form to the Department, and prepare a SWPPP. The SWPPP must be available to the Department (if requested) and maintained on site. This process does not provide for public access and notification (other than the publication in a newspaper, which is easily overlooked by the public).

The public, including immediately adjacent property owners, should have opportunity for notification when such notification is submitted to the Department.

Many local governments have adjacent property owner notification requirements as part of the local zoning and land development process. Since this process does not apply to HVHF, a process of notification to adjacent and potentially impacted property owners should be included in Section II.A. Clarification of the definition of "potentially impacted property owners" requires further consideration in the RDSGEIS. Potentially, notice should be provided to water suppliers, etc.

If coverage under the GP is dependent upon development and implementation of the SWPPP, then the SWPPP must be available for public review upon request. It is likely that most members of the general public would not necessarily know how to request or obtain a copy of the SWPPP. As previously suggested, an on-line database would allow public and Department access to the SWPPP. It is unreasonable to allow the industry to obtain GP coverage without an opportunity for public comment.

Comment 10:

B.2.3.b General Permit Authorization – Given the unique nature of HVHF construction, and the lack of local government review regarding land use disturbance and stormwater management, the permit should impose a time period between preparation and submission of any and all required materials and actual permit coverage. All material should be digitally submitted and all information regarding land disturbance activities should be available and accessible for public review and comment, with a minimum 30-day period for public comment before permit coverage. HVHF practices are different from other industrial practices and coverage under a general permit must provide some process for public review and comment on permit coverage.

Comment 11:

C. Impaired Waters and TMDLs – The RDSGEIS has not provided any documentation or consideration as to whether a general permit is sufficient to prevent further water quality impacts in impaired waters and especially watersheds with TMDLs. A requirement should be imposed for the permit applicant to identify to the Department when the discharge will occur in impaired waters, and what specific additional measures are being implemented to provide protection for the specific pollutants of concern. The Department should maintain specific records and documentation of HVHF activities in impaired waters. Additional monitoring and reporting requirements are warranted in impaired waters, and should be submitted to the Department, not just maintained on site.

Part III – DEVELOPMENT AND ADMINISTRATION OF THE CONSTRUCTION SWPPP

Comment 12:

A.3. Development of the Construction SWPPP – Section 5.1 of the RDSGEIS identifies a number of types of land disturbance activities associated with HVHF including utility corridors (including gathering lines), compressor facilities, and access roads associated with compressor facilities. However, the construction of gathering lines, compressor facilities and the access roads associated therewith is not required to be addressed in the SWPPP. The GP and the required SWPPP contents should be revised to include construction and stormwater discharges related to gathering lines, compressor stations and associated access roads, as well as those facilities currently listed under this section.

Comment 13:

C.1. Disturbance of more than five (5) acres – If phased construction is planned, with a maximum of five acres disturbed in any phase, the permitting of greater disturbance may be permissible under the SPDES HVHF GP as it is currently written.

Recommendation: The SPDES HVHF GP should be revised to require approval when the soil disturbance activities will result in more than five acres of disturbance at any one time, or more than five acres of disturbance over the life of the project.

Recommendation: The SPDES HVHF GP should be revised to effectively cover all areas not in AA, AA-Special, or FAD areas.

Part IV CONTENTS OF SWPPP

Comment 14:

A. What the Construction SWPPP Must Achieve –The SPDES HVHF GP requires well sites to be *designed to minimize environmental impacts* through the minimization of clearing and grading; and avoidance of sensitive areas such as erodible soils, steep areas, and critical habitats. However, the SPDES HVHF GP does not indicate how the permittee will achieve this.

Recommendation: The SPDES HVHF GP should be revised to clearly indicate how sensitive areas will be identified in permittee submission packages and require the identification to be done so at a mapping scale adequate to clearly identify all potential sensitive areas to ensure clearing and grading will be minimized accordingly. This requirement also applies to setback requirements around waterbodies. (See additional comments under Part IV.C.1. and Part IV.A.)

Comment 15:

B.1.b. and e. Effluent Limitation Requirements – The SPDES HVHF GP requires compliance with erosion and sediment controls to *minimize the discharge of pollutants,* specifically the control of stormwater and sediment discharges, but does not require supporting calculations to be submitted.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit calculations supporting any claim of compliance with mandatory control of stormwater, sediment, or other pollutant discharges.

Comment 16:

C.1.b. Erosion and sediment control components - The SPDES HVHF GP requires a site map/construction drawing(s) that include information vital to erosion and sediment control considerations, including wetlands, potentially affected surface waters, existing and final slopes, and location(s) of stormwater discharges. However, there is no maximum scale identified for this requirement. It is possible that sensitive features may be overlooked and steep slopes unidentified if mapping is at too large a scale.

Recommendation: The SPDES HVHF GP should be revised to require mapping at a maximum scale no greater than 1" = 100' to ensure adequate identification of features to be avoided or protected during construction.

Comment 17:

C.1.i. Erosion and sediment control components – The inspection schedule, as well as the corresponding inspection reports should be made available with the SWPPP for Department access. At a minimum, the inspection schedule should be made available to the public and include a Department contact where concerns may be reported.

Comment 18:

D.1.b. Post-construction stormwater management practice component - The SPDES HVHF GP requires a well site map/construction drawing(s) that include information vital to post-construction stormwater management practice evaluation, including the specific location and size of each post-construction stormwater management practice. However, there is no maximum scale identified for this requirement. It is possible that the regulatory review of post-construction stormwater management practices may be inadequate if mapping is at too large a scale.

Recommendation: The SPDES HVHF GP should be revised to require mapping at a maximum scale no greater than 1” = 100’ to ensure adequate identification and evaluation of proposed post-construction stormwater management practices.

Comment 19:

D.1.e. Post-construction stormwater management practice component - The SPDES HVHF GP requires a hydrologic and hydraulic analysis for all structural components of the stormwater management control system. However, the SPDES HVHF GP does not require supporting calculations to be submitted in support of these analyses. Without supporting calculations, regulators will be limited in the ability to effectively review the appropriateness of the proposed system.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit calculations supporting the hydrologic and hydraulic analysis of all structural components of the proposed stormwater management control system. All calculations and information should be available to the public upon request.

Comment 20:

D.1.f. Post-construction stormwater management practice component – The SPDES HVHF GP requires a detailed summary of the sizing criteria that were used to design all post-construction stormwater management practices *including calculations* to be submitted with the SWPPP. The SPDES HVHF GP requires the summary to address, at a minimum, the required design criteria from applicable chapters of the 2010 New York State Stormwater Management Design Manual.

However, the SPDES HVHF GP does not indicate that the calculations are site specific. Given the variability of site conditions throughout any given project, it is essential that the post-construction stormwater management practices be designed to address the unique considerations of both the site conditions and the functional practicality of any proposed post-stormwater management practice.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit site-specific calculations supporting the design of all proposed stormwater management practices to ensure they are appropriate for site-specific conditions.

Comment 21:

E. Enhanced Phosphorous Removal Standards – The SPDES HVHF GP requires post-construction stormwater management practices to be designed in conformance with the Enhanced Phosphorous Removal Standards included in the 2010 New York State Stormwater Design Manual. However, the SPDES HVHF GP does not require permittees to submit documented implementation of this requirement.

Recommendation: The SPDES HVHF GP should be revised to require permittees to document the implementation of the Enhanced Phosphorous Removal Standards within the SWPPP as part of their permit application package.

Part V-CONSTRUCTION OF WELL SITE – INSPECTION, MAINTENANCE, AND RECORDKEEPING REQUIREMENTS

Comment 22:

D. Recordkeeping – The SPDES HVHF GP requires all inspection reports to be maintained on the *well site* with the *Construction SWPPP*. Without a requirement to submit inspection reports or, at a minimum, a list of violations and corrective actions required, to the Department, the inspection reports may not serve their intended purpose. Regardless of limitations to staff and funding, the Department should maintain responsibility for ensuring compliance with applicable regulations. The utilization of *qualified inspectors* is only one part of ensuring compliance and should be supplemented with quality control checks by the Department, which may be done by performing random reviews of documents submitted electronically to a Department database similar to that mentioned in previous comments.

Recommendation: The SPDES HVHF GP should require electronic submission of inspection reports or, at a minimum, a list of violations and correctives actions required, to the Department. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments. Additionally, the Department should conduct quality control reviews of inspection documents to ensure compliance is being achieved.

Part VI CONSTRUCTION PHASE COMPLETION

<u>Comment 23:</u>

B. Inspections – The SPDES HVHF GP requires from qualified inspectors, by signature, a statement certifying achievement of final site stabilization. However, the SPDES HVHF GP does not require any documentation supporting this certification.

Recommendation: The SPDES HVHF GP should be revised to require documentation, specifically time/date-stamped digital photographs, to support certification of final stabilization.

Part VII HVHF SWPP

<u>Comment 24:</u>

Part VII General comment – Would an applicant be permitted to submit one generic document to be applied at multiple sites? If so, it is unlikely that all relevant issues will be adequately addressed.

Recommendation: The SPDES HVHF should be revised to require a site-specific SWPPP as described in previous comments to ensure adequate protection and mitigation measures are proposed.

<u>Comment 25:</u>

A.5. Development of the HVHF SWPPP – The SPDES HVHF GP requires the HVHF SWPPP to be developed by someone knowledgeable in the principles and practices of stormwater management and groundwater protection associated with the HVHF Phase and the Production Phase. The SPDES HVHF GP specifically mentions a Professional Engineer. However, the principles and practices of groundwater protection are often best performed by a Professional Hydrogeologist.

Recommendation: The SPDES HVHF GP should be revised to reference the appropriate professional disciplines necessary to adequately address both stormwater management (Professional Engineer) and groundwater protection (Professional Hydrogeologist).

<u>Comment 26:</u>

A.11 Development of the HVHF SWPPP – The SPDES HVHF GP allows the Department to issue an immediate stop work order upon a finding of significant non-compliance of the HVHF SWPPP or violation of the GP.

Recommendation: The ability to issue a stop-work order is a great option for the Department and should be supplemented by random quality control reviews performed as described in previous comments.

Part VIII HVHF OPERATION REQUIREMENTS

Comment 27:

A.1. and 2. General Requirements – The SPDES HVHF GP requires owners and operators to develop and evaluate alternatives for HVHF Phase fluid additives and to maintain a list of all HVHF Phase fluid additives on-site. The Department must make clear that propriety information must not be excluded from this list.

Comment 28:

A.4. General Requirements – The SPDES HVHF GP requires qualified inspectors to sign a statement certifying achievement of final site stabilization prior to initiating the HVHF Phase. However, the SPDES HVHF GP does not require any documentation supporting this certification.

Recommendation: The SPDES HVHF GP should be revised to require documentation, specifically time/date-stamped digital photographs, to support certification of final stabilization.

Comment 29:

A.6. General Requirements – The SPDES HVHF GP requires Department inspector verification of partial site reclamation. However, the SPDES HVHF GP does not address the procedures necessary if partial site reclamation is not sufficient.

Recommendation: The SPDES HVHF GP should be revised to detail the process for addressing sites where the requirements for partial site reclamation are insufficient.

Part IX CONTENTS OF THE HVHF SWPPP

Comment 30:

A.2. HVHF General SWPPP Requirements – The SPDES HVHF GP requires a site map that includes information critical to adequately review and evaluate the HVHF

SWPPP. Specifically, the SPDES HVHF GP cites a *USGS quadrangle or other map.* While a USGS quadrangle map may be adequate for showing general site location, it is not appropriate for showing detailed information. It is possible that the regulatory review of the HVHF SWPPP may be inadequate if mapping is at too large a scale.

Recommendation: The SPDES HVHF GP should be revised to require mapping at a maximum scale no greater than 1" = 100' to ensure adequate identification and evaluation of proposed post-construction stormwater management practices. Specifically, this section of the SPDES HVHF GP should be revised as follows:

b. Directions of stormwater flow should be shown on a contoured map with contours shown at minimum 5-ft intervals.

e. The scale for maps showing the locations of items listed in this section should be mapped at an appropriate defined scale (e.g. 1"=50' maximum). This section should also include the location of gathering lines.

g. Drainage area maps and stormwater outfall locations should be submitted on a separate stormwater map, attached to the site map, to ensure correct documentation.

i. The procedure for determining areas with significant potential for causing erosion should be defined or, if already defined in other documents, referenced.

Comment 31:

A.4. HVHF General SWPPP Requirements – This section requires the name, classification, and distance from the nearest edge of the well pad to the nearest receiving water(s). Submission of this information in narrative form may be sufficient, but an appropriately scaled map with labeled features would also provide an easily-verifiable document.

Recommendation: The SPDES HVHF GP should be revised to require a map showing the name, classification, and distance from the nearest edge of a well pad to the nearest receiving water(s) at a legible scale.

<u>Comment 32:</u>

A.7. HVHF General SWPPP Requirements – The inclusion of gravel is important when considering the total imperviousness of the well site. The compaction of subsoils and clogging with fine sediment within gravel areas has been shown to function as an impervious surface with regard to stormwater runoff.

<u>Comment 33:</u>

A.7. HVHF General SWPPP Requirements – This section includes an equation for estimating the total imperviousness of a well site as:

> Area of Roofs + Area of Paved and Other *Impervious* Surfaces, including gravel and roads = Total Area of *Well site.*

This equation should be revised as follows:

> Area of Roofs + Area of Paved and Other *Impervious* Surfaces, including gravel and roads = Total <u>Impervious Surface</u> Area of *Well site.*

<u>Comment 34:</u>

A.11. HVHF General SWPPP Requirements – The SPDES HVHF GP requires a summary of discharge sampling data to be maintained on the well site. Without a requirement to submit sampling data to the Department, it is possible that discharges in violation of the SPDES HVHF GP may be overlooked. Regardless of limitations to staff and funding, the Department should maintain responsibility for compliance and enforcement through quality control checks.

Recommendation: Quality control checks should be performed by the Department and facilitated by the submission of sampling data to the Department electronically. Checks should then be verified through cross-checking submitted sampling data against Department-collected sample data. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments.

<u>Comment 35:</u>

A.13. HVHF General SWPPP Requirements – In addition to identifying the proposed sources or any water to be used at the well site, an estimate of proposed volume to be withdrawn from each source will assist in tracking any pollutants found in that water.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit estimated volumes to be withdrawn from each identified water source.

<u>Comment 36:</u>

A.16. HVHF General SWPPP Requirements – The SPDES HVHF GP requires the HVHF SWPPP to include a description of stormwater management controls appropriate for the *well site*. However, the SPDES HVHF GP does not indicate that this description will include site specific sizing calculations. Given the variability of site conditions throughout any given project, it is essential that stormwater management controls be designed to address the unique considerations of both the site conditions and the functional practicality thereof.

Recommendation: The SPDES HVHF GP should be revised to require permittees to submit site specific sizing calculations supporting the design of all proposed stormwater management controls to ensure they are appropriate for site-specific conditions. Site-specific stormwater management controls should be evaluated for design and performance through inspection reporting and quality control as described in previous comments.

Comment 37:

A.18.k. HVHF General SWPPP Requirements – The SPDES HVHF GP requires the HVHF SWPPP to include information about partial site reclamation, including a requirement that reclaimed areas be seeded and mulched after topsoil replacement and reestablishment of vegetative cover. Standards for acceptable seeding, maintenance of seeded areas, and soil restoration should be defined in order to ensure reclamation, revegetation, and continued stabilization are achieved.

Recommendation: The SPDES HVHF GP should be revised to include by definition or reference standards for acceptable seeding, maintenance of seeded areas, and soil restoration.

Comment 38:

B.1.p. Required Non-Structural BMPs - The SPDES HVHF GP requires the owner or operator to use absorbents for dry cleanup whenever possible. However, the SPDES HVHF GP does not address the disposal of used absorbents.

Recommendation: The SPDES HVHF GP should be revised to address the disposal of used absorbents in accordance with NYS and EPA guidelines.

Comment 39:

C. Required Structural BMPs – The SPDES HVHF GP requires the HVHF SWPPP to "describe the traditional stormwater management practices…that currently exist or that are planned." However, the SPDES HVHF GP does not require calculations supporting the capacity of existing stormwater management practices to manage additional stormwater from newly constructed well sties, nor does the SPDES HVHF GP require supporting calculations for design of proposed stormwater management practices. Without a thorough review prior to issuance of the GP, it is possible that stormwater management practices will be inadequate to effectively address stormwater runoff from well sites.

Recommendation: - The SPDES HVHF GP should be revised to require the submission of calculations supporting the capacity of existing stormwater management practices and the design of proposed stormwater management practices to effectively manage stormwater runoff resulting from the construction and operation of a well site.

Part X ACTIVITIY-SPECIFIC STRUCTURAL AND NON-STRUCTURAL BMPs AND BENCHMARK MONITORING REQUIREMENTS

Comment 40:

A.5. General – The SPDES HVHF GP states that "if the [HVHF] activities are conducted for less than one (1) calendar year, all stormwater monitoring requirements must be satisfied during the period of activity. If no qualifying storm event occurs during the period of activity, or no qualifying storm event results in a *discharge*, monitoring requirements must be completed during the first qualifying storm that results in a *discharge*." However, the SPDES HVHF GP does not define the term "qualifying storm event." To ensure adequate monitoring of stormwater resulting from HVHF activities, the monitoring and sampling requirements must be clearly defined in order for permittees to satisfy the conditions of the permit.

Recommendation: The SPDES HVHF GP should be revised to include a clear definition of the term "qualifying storm event."

Comment 41:

D. Vehicle and equipment cleaning areas – The SPDES HVHF GP states that "discharge of vehicle and equipment wash waters … are not authorized by the SPDES HVHF GP and must be covered under a separate SPDES permit or discharged to a sanitary sewer in accordance with applicable industrial pretreatment requirements or transported off-site for proper disposal." The intent of the SPDES HVHF GP was to streamline and condense the permitting process for HVHF activities. Requiring a separate permit for the discharge of vehicle and equipment wash waters seems redundant in light of the ability of the SPDES HVHF GP to cover all other HVHF activities.

Recommendation: The SPDES HVHF GP should be revised to incorporate all the provisions necessary to meet New York State permitting requirements within a single permit, including the provisions necessary to authorize discharges from vehicle and equipment wash waters or require off-site transportation for disposal.

Comment 42:

J. Piping/conveyances – The SPDES HVHF GP requires the HVHF SWPPP to include and describe measures that prevent or minimize the contamination of surface runoff from spills and leaks from piping/conveyance systems used for transferring "fresh water, *flowback* water, *production brine*, well *stimulation* water, sanitary, and other wastewaters." However, the SPDES HVHF GP does not address this requirement for piping/conveyance systems used for transferring the gas produced by each well site. Failure to address the piping/conveyance systems used for gas transmission may result in inadequate protection of surface waters in the event of a leak or spill of gas.

Recommendation: The SPDES HVHF GP should be revised to address all piping/conveyances, including gas transmission systems.

Comment 43:

J.2.p. Piping/conveyances – The SPDES HVHF GP states, "pipelines buried under stream crossings shall be buried below the scouring depth and may require other permits." The SPDES HVHF GP does not require the submission of supporting calculations for determination of scour depth, nor does it clearly define the conditions under which "other permits" may be required. Furthermore, it seems that NYSDEC does not require stream crossing permits for activities other than silviculture. This lack of oversight may result in significant impacts to surface waters due to the potential thousands of crossings at headwater streams to facilitate HVHF activities.

Recommendation: The SPDES HVHF GP should be revised to require submission of calculations supporting the determination of scour depth for the placement of buried pipeline stream crossings.

Recommendation: The SPDES HVHF GP should be revised to clearly define which "other permits" may be required and the conditions under which those "other permits" are applicable.

Recommendation: NYSDEC should examine current stream crossing requirements and develop more robust regulations to ensure proposed crossings are constructed and maintained appropriately and do not impact water quality.

Comment 44:

M. Freshwater Surface Impoundments and Reserve Pits – The SPDES HVHF GP states, "a closed-loop tank system must be used instead of a reserve pit to manage drilling fluids and cuttings for any of the following: a) horizontal drilling in the Marcellus Shale unless an acid rock drainage mitigation plan for onsite burial of such cuttings is approved by the Department; and; b) any drilling requiring cuttings to be disposed of off-site, as provided in Part 360 of this Title, including at a landfill." However, the SPDES HVHF GP does not define an "acid rock drainage mitigation plan." The SPDES HVHF GP also does not clearly identify the reference to Part 360 in section (b), above.

Recommendation: The SPDES HVHF GP should be revised to include a section defining an "acid rock drainage mitigation plan" which includes the conditions under which the plan must be developed, the issues which the plan must address (including any necessary supporting calculations), and the contents which must be included in the plan.

Recommendation: The SPDES HVHF GP should be revised to clearly identify the statute included in part (b) of this section which references the off-site disposal of cuttings.

Part XII HVHF PHASE MONITORING

Comment 45:

A. Schedule for Monitoring – The SPDES HVHF GP requires a schedule for visual monitoring and examination of stormwater discharges at each outfall after each qualifying storm that must document observed color, odor, clarity, floating solids, settled solids, suspended solids, foam, and oil sheen. However, the SPDES HVHF GP does not require sampling, even if the visual observations indicate the presence of pollutants.

Recommendation: The SPDES HVHF GP should be revised to clearly define sampling requirements. At a minimum, sampling and laboratory testing should be required if a visual examination indicates the presence of pollutants.

Comment 46:

A. Schedule for Monitoring – The SPDES HVHF GP requires visual examination documents to be maintained on the well site. Also, the SPDES HVHF GP does not require photographic documentation to support visual examination reports. The Department should perform quality control checks, which may be done by performing random reviews of documents submitted electronically to a Department database similar to that mentioned in previous comments.

Recommendation: The SPDES HVHF GP should require electronic submission of visual examination reports, including photos, to the Department. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments. Additionally, the Department should conduct quality control reviews of visual examination documents to ensure compliance is being achieved.

Comment 47:

A. Schedule for Monitoring – The SPDES HVHF GP states, "all samples (except snowmelt samples) must be collected from the *discharge* resulting from a storm event that is greater than 0.1 inches in magnitude and that occurs at least seventy-two (72) hours from the previously measurable (greater than 0.1 inch rainfall) storm event. The 72-hour storm interval is waived if the preceding measurable storm did not result in a stormwater *discharge* (e.g., a storm event in excess of 0.1 inches may not result in a stormwater *discharge* at some facilities)." Is this the intended definition of "qualifying storm event?"

Comment 48:

A. Schedule for Monitoring – The SPDES HVHF GP states, "if a visual examination was performed and the storm event was later determined not to be a measurable (greater than 0.1 inch rainfall) storm event, the visual examination should still be included in the *HVHF SWPPP* records." The inclusion of all visual examination reports in the HVHF SWPPP record should be required.

Recommendation: The SPDES HVHF GP should be revised to state, "if a visual examination was performed and the storm event was later determined not to be a measurable (greater than 0.1 inch rainfall) storm event, the visual examination must still be included in the *HVHF SWPPP* records."

Comment 49:

A.3.c. Schedule for Monitoring – This section of the SPDES HVHF GP requires samples to be analyzed within ten calendar days after they have been collected.

This information may be more logically located in section A.10.b. which discusses collection and analysis of samples.

Recommendation: The SPDES HVHF GP should be revised to move the above referenced requirement for analysis of samples from Part XII.A.3.c. to Part XII.A.10.b.

Comment 50:

A.3.d. Schedule for Monitoring – This section of the SPDES HVHF GP states, "the benchmark concentrations do not constitute direct numeric effluent limitations and, therefore, an exceedance is not a general permit violation." What is the purpose of benchmark monitoring if exceedance of the benchmark concentrations listed in Part X of the SPDES HVHF GP do not result in a general permit violation?

Recommendation: The SPDES HVHF GP should be revised to omit this sentence from the document. Exceeding benchmark concentrations should immediately result in a violation of the GP to ensure proper corrective action is taken to protect water quality.

Comment 51:

A.3.f. Schedule for Monitoring – The SPDES HVHF GP requires benchmark monitoring results to be documented and maintained on the well site. The Department should perform quality control checks, which may be done by performing random reviews of documents submitted electronically to a Department database similar to that mentioned in previous comments.

Recommendation: The SPDES HVHF GP should require electronic submission of benchmark monitoring results, including corrective actions needed, to the Department. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments. Additionally, the Department should conduct quality control reviews of benchmark monitoring documents to ensure compliance is being achieved.

Comment 52:

A.10.b. Schedule for Monitoring – The SPDES HVHF GP states that "sampling requirements must be assessed on an outfall-by-outfall basis." However, there are no criteria upon which sampling requirements are to be assessed. The SPDES HVHF GP also fails to identify the party responsible for directing sampling requirements at each outfall. Sampling requirements should be directed by NYSDEC guidance criteria, to include frequency of collection and analysis requirements.

Recommendation: The SPDES HVHF GP should be revised to clearly identify the Department as the party responsible for directing sampling requirements at each outfall.

Recommendation: The NYSDEC should develop guidance criteria for sampling requirements for HVHF activities. This guidance criteria should address the conditions under which sample collection is required (i.e., when a visual examination indicates the presence of pollution), location of sample collection, frequency of sample collection, and laboratory analysis requirements for collected samples.

Recommendation: The SPDES HVHF GP should be revised to require sampling in accordance with NYSDEC guidance criteria, to include frequency of collection and analysis requirements.

Comment 53:

A.10.b. Schedule for Monitoring – This section of the SPDES HVHF GP does not reference the ten-day time limit for analysis of collected samples.

Recommendation: This section of the SPDES HVHF GP should be revised to include reference to the ten-day time limit for analysis of collected samples included in Part XII.A.3.c.

Comment 54:

A.10.c. Schedule for Monitoring – This section of the SPDES HVHF GP requires owners/operators to provide the date and duration of sampled storm events, rainfall measurements or estimates (in inches) of the storm event that generated the sampled runoff, time between storm events greater than 0.1 inch, and an estimate of volume sampled. A rain gauge/weather station should be required to ensure rainfall greater than 0.1 inch is accurately recorded. This will also ensure visual examination and sampling is completed for events greater than 0.1 inch.

Recommendation: The SPDES HVHF GP should be revised to require rainfall measurements and remove references to rainfall estimates to ensure monitoring and sampling in compliance with the conditions of the permit.

Part XIII HVHF PHASE REPORTING

Comment 55:

A. Discharge Monitoring Reports (DMR) – The SPDES HVHF GP requires the results of laboratory analysis of samples to be submitted to the Department on preprinted DMRs within ten days of their receipt. The required formatting of DMRs lends itself very easily to standardization for electronic submission to the Department, which would allow for faster submission and reduce the costs incurred by both the Department and permittees by eliminating unnecessary paper and paperwork. Furthermore, the Department should perform quality control checks, which may be done by performing random reviews of documents submitted electronically to a Department database similar to that mentioned in previous comments.

Recommendation: The SPDES HVHF GP should require electronic submission of DMRs, in approved format via online forms, to the Department. These submissions should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments. Additionally, the Department should conduct quality control reviews of benchmark monitoring documents to ensure compliance is being achieved.

Part XIV MONITORING FOR THE PRODUCTION PHASE AND TEMPORARY SUSPENSION OF THE HVHF PHASE

Comment 56:

A. Schedule for Monitoring – Please see comments 45, 46, 49, 50, 51, 52, 53, and 54, and the corresponding recommendations as they apply to this section of the SPDES HVHF GP.

Part XVI PRODUCTION PHASE REPORTING

Comment 57:

A. Discharge Monitoring Reports (DMR) – Please see comment 55 and the corresponding recommendation as it applies to this section of the SPDES HVHF GP.

Part XXI. STANDARD GENERAL PERMIT CONDITIONS

Comment 58:

F. Duty to Provide Information – The SPDES HVHF GP states, "the NOI, SWPPP and inspection reports required by this general permit are public documents that the *owner or operator* must make available for review and copying by any person within five (5) business of the *owner or operator* receiving a written request by any such person to review the NOI, SWPPP or inspection reports. Copying of documents will be done at the requester's expense." Many HVHF well sites prohibit access by the general public, and all of the public documents indicated are required by the SPDES HVHF GP to be kept on the well site. In order to expedite requests and eliminate man-hours necessary to escort individuals through restricted areas, as well as provide for the recommendations above, the Department should require the electronic submission of all public documents. These documents should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments.

Recommendation: The SPDES HVHF GP should be revised to allow for the electronic submission of all public documents. These documents should be managed in a Department database similar to that mentioned in previous comments. The Department database should also be accessible to the public in a manner described in previous comments.

Attachment A

Technical Information in support of comments:

1. Sediment Loads from Gravel Roads

   The Pennsylvania Center for Dirt and Gravel Road Studies provides information on measures to maintain gravel roads in a manner to reduce the discharge of pollutants and protect water quality. Penn State's Center for Dirt and Gravel Road Studies (Center) recently completed a research project for the Chesapeake Bay Commission (Scheetz, Summary Statement) that begins to quantify sediment production from gravel roads and sediment reductions from several commonly used practices. This study found that:

   > **Runoff Rates from Existing Roads:**
   > *"The five "existing condition" tests done for this study found sediment production rates ranging from 0.7-12.2 pounds of sediment runoff in a single 30 minute, 0.55 inches simulated rainfall. The 0.7 pound event was generated from a flat narrow farm lane with grass growing between the wheel tracks. The 12.2 pound event was generated from a wider, mixed limestone/clay road at a 4-5% slope. This highlights the great variability in erosion rates based on specific site conditions. Using the average sediment runoff rate of 5.6 pounds per event, a single 30 minute 0.55 inch rain event moving across Pennsylvania can be conservatively expected to generate over 3,000 tons* of sediment form the State's 20,000+ miles of public unpaved roads".*

   This research supports that gravel roads can be a significant source of pollutants such as sediment. As discussed in several comments, there is a need for the RDSGEIS to estimate the cumulative impact of gravel road development as a result of HVHF activity.

2. **Water Quality Impacts from Gas Drilling Activities**

   In 2005, the U.S. Environmental Protection Agency (U.S. EPA) awarded a grant to the City of Denton, Texas, to monitor and assess the impact of gas well drilling on stormwater runoff. The results of this effort were published in December 2007 in a report titled “Demonstrating the Impacts of Oil and Gas Exploration on Water Quality and How to Minimize These Impacts Through Targeted Monitoring Activities and Local Ordinances.” With regards to the discharge of sediment during construction, this study determined that:

> *“Gas well sites have the potential to produce sediment loads comparable to traditional construction sites.*
>
> - *Total suspended solids (TSS) and turbidity event mean concentrations (EMC = pollutant mass / runoff volume) at gas sites were significantly greater than at reference sites (the median TSS EMC at gas sites was 136 times greater than reference sites).*
>
> - *Compared to the median EMCs of storms sampled by Denton near one of their outfalls, the gas well site median EMC was 36 times greater.*
>
> - *Gas site TSS EMCs ranged from 394 to 9898 mg/l and annual sediment loadings ranged from 21.4 to 40.0 tonnes/hectare/year (tonne = 1000 Kg; hectare = 10,000 square meters), and were comparable to previous studies of construction site sedimentation”*.

This study concludes that “Gas well sites have the potential to negatively impact surface waters due to increased sedimentation rates.” (US EPA ID No. CP-83207101-1, page 2).

In addition to the well pad site, roads that are constructed, widened, or altered for vehicle access to and from the well pad site can be a source of sediment and pollutants during both construction and operation. The U.S. EPA Publication “Erosion, Sediment and Runoff Control for Roads and Highways” (EPA-841-F-95-008d) states that:

> Runoff controls are essential to preventing polluted runoff from roads, highways, and bridges from reaching surface waters. Erosion during and after construction of roads, highways, and bridges can contribute large amounts of sediment and silt to runoff waters, which can deteriorate water quality and lead to fish kills and other ecological problems.
>
> Heavy metals, oils, other toxic substances, and debris from construction traffic and spillage can be absorbed by soil at construction sites and carried with runoff water to lakes, rivers,

> and bays. Runoff control measures can be installed at the time of road, highway, and bridge construction to reduce runoff pollution both during and after construction. Such measures can effectively limit the entry of pollutants into surface waters and ground waters and protect their quality, fish habitats, and public health.

This publication (EPA-841-F-95-008d) identifies a number of pollutant types and sources related to Roads and Highways, as identified in Table 1.

Table 1. Typical pollutants found in runoff from roads and highways.

Erosion, Sediment and Runoff Control for Roads and Highways | Polluted Runoff | US EPA

	Pollutant	**Source**
Sedimentation	Particulates	Pavement wear, vehicles, the atmosphere and maintenance activities
Nutrients	Nitrogen & Phosphorus	Atmosphere and fertilizer application
Heavy Metals	Lead	Leaded gasoline from auto exhausts and tire wear
	Zinc	Tire wear, motor oil and grease
	Iron	Auto body rust, steel highway structures such as bridges and guardrails, and moving engine parts
	Copper	Metal plating, bearing and brushing wear, moving engine parts, brake lining wear, fungicides & insecticides
	Cadmium	Tire wear and insecticide application
	Chromium	Metal plating, moving engine parts and brake lining wear
	Nickel	Diesel fuel and gasoline, lubricating oil, metal plating, bushing wear, brake lining wear and asphalt paving
	Manganese	Moving engine parts
	Cyanide	Anti-caking compounds used to keep deicing salt granular
	Sodium, calcium & chloride	Deicing salts
	Sulphates	Roadway beds, fuel and deicing salts
Hydrocarbons	Petroleum	Spills, leaks, antifreeze and hydraulic fluids and asphalt surface leachate

References

1. Center for Rural Pennsylvania "the Impact of Marcellus Gas drilling on Rural Drinking Water Supplies", October 2011.

2. Entrekin, Sally, et al, "Rapid Expansion of Natural Gas Development Poses a Threat to Surface Waters", From Frontiers in Ecology 2011; 9(9): 503-511, Oct 2011.

3. Etowah Aquatic Habitat Conservation Plan "Utility Stream Crossings Policy", July 13, 2006.

4. Handlerof, Stephanie; League of Women Voters of Indiana "Marcellus Shale Natural Gas Extraction Study 2009-2010 Study Guide V: Regulation and Permitting of Marcellus Shale Drilling", League of Women Voters of Pennsylvania, 2010.

5. Kaplan, Louis, et al "Protecting Headwaters: The Scientific Basis For Safeguarding Stream And River Ecosystems, A Research Synthesis from the Stroud Water Research Center " 2008.

6. Leopold, Luna B.; "A View of the River", Harvard University Press, Cambridge, MA, 1994.

7. NYDEC "Stream Crossings Protecting and Restoring Stream Continuity" web page at http://www.dec.ny.gov/permits/49060.html.

8. O'Dell, Patrick M., Professional Engineer in Petroleum Engineering, National Park Service Geologic Resources Division, "Potential for Development of Natural Gas Exploratory Wells to Adversely Affect Water Resources of the Delaware River Basin", Nov 23, 2010.

9. Reid, Scott M. and Paul G. Anderson "Effects of Sediment released During Open-cut Pipeline Water Crossings, Canadian water Resources Journal Vol. 24, No 3, 1999.

10. Scheetz, Dr. Barry E. and Steven M. Bloser; Center for Dirt and Gravel Road Studies, The Pennsylvania State University, University Park, PA 16802; "Environmentally Sensitive Maintenance Practices for Unpaved Roads: Sediment Reduction Study" Prepared for Chesapeake Bay Commission c/o Senate of Pennsylvania G-05 North Office Building Harrisburg, PA 1712, FINAL REPORT June 30, 2008, Revised August 29, 2008 and Summary Statement

11. United States Environmental Protection Agency "Erosion, Sediment and Runoff Control for Roads and Highways", Office of Water (4503F) EPA-841-F-95-008d, December 1995

12. United States Environmental Protection Agency, Final Report for Catalog of Federal Domestic Assistance Grant Number 66.463 Water Quality Cooperative Agreement for Project Entitled "Demonstrating the Impacts of Oil and Gas Exploration on Water Quality and How to Minimize these Impacts Through Targeted Monitoring Activities and Local Ordinances" and "Summary of the Results of the Investigation Regarding Gas Well Site Surface Water Impacts", ID No. CP-83207101-1, Kenneth E. Banks, Ph.D. Manager, Division of Environmental Quality and David J. Wachal, M.S. Water Utilities Coordinator

13. United States Environmental Protection Agency, Wadable stream assessment: a collaborative survey of the nation's streams, 2006. EPA 841-B-06-002.

14. Letter from James A. Schmid, PhD, Schmid & Company Consulting Ecologists to Scott E. Walters, Chief General Permits Bureau of Waste Management PaDEP, 8 November 2011.

Attachment 7

The Louis Berger Group, Inc.

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Memorandum

TO: Kate Sinding, Natural Resources Defense Council

FROM: Niek Veraart, Louis Berger Group

DATE: January 11, 2012

RE: Technical Review Comments on the 2011 Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program and Proposed High-Volume Hydraulic Fracturing Regulations (Proposed Express Terms 6 NYCRR Parts 550 through 556 and 560)

1.0 Introduction

The Louis Berger Group Inc. (LBG) reviewed the 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS), the proposed Environmental Assessment Form (EAF) and EAF Addendum (RDSGEIS Appendices 5 and 6), the proposed Supplemental Permit Conditions (RDSGEIS Appendix 10) and the proposed High-Volume Hydraulic Fracturing (HVHF) regulations (Proposed Express Terms 6 NYCRR Parts 550 through 556 and 560) for the following topics:

- Noise (RDSGEIS Sections 2.4.13 and 6.10)
- Ground-borne noise and vibration (impacts not addressed in the RDSGEIS)
- Visual impacts (RDSGEIS Sections 2.4.12 and 6.9)
- Land use (impacts not addressed in the RDSGEIS)
- Transportation (RDSGEIS Sections 2.4.14 and 6.11)
- Community character (RDSGEIS Sections 2.4.15 and 6.11)
- Cultural resources (impacts not addressed in the RDSGEIS).
- Aquatic Ecology (RDSGEIS Sections 6.1.1.2, 6.1.1.3 and 6.1.1.4).

For each topic, the following sections address the sufficiency of the RDSGEIS impact analyses and proposed mitigation measures in meeting State Environmental Quality Review Act (SEQRA--6 NYCRR Part 617) requirements. The comments also identify specific improvements and best practice approaches that the New York State Department of Environmental Conservation (NYSDEC) could use to resolve the deficiencies identified and minimize the environmental impacts of High-Volume Hydraulic Fracturing (HVHF) and related development in New York.

2.0 Noise

2.1 Construction Impacts

The 2011 RDSGEIS quantitative construction noise assessment uses information from the Federal Highway Administration's Road Construction Noise Model to estimate noise levels at various distances from the construction site and represents a substantial improvement over the qualitative analysis in the 2009 Draft Supplemental Generic Environmental Impact Statement (DSGEIS). For quiet rural areas, the results show that construction activities would result in significant adverse impacts under NYSDEC criteria (increase of 6 dBA (A-weighted decibels) or more over existing conditions) at distances exceeding 2,000 feet.

The RDSGEIS provides the requisite construction noise analysis, but fails to appropriately evaluate and discuss the significance of the model results. Instead, a one sentence conclusion is provided: “Such levels would not generally be considered acceptable on a permanent basis, but as a temporary, daytime occurrence, construction noise of this magnitude and duration is not likely to result in many complaints in the project area.”

Contrary to this statement, there is no regulatory requirement that access road construction and site preparation be limited to daytime hours. To mitigate this significant adverse impact, a prohibition on nighttime construction should be included in the HVHF regulations or supplemental permit conditions to avoid annoyance and sleep disturbance of nearby residences, along with other construction noise control best practices (See Section 2.6 infra).

Further, the assertion in the RDSGEIS that construction noise impacts are “temporary” ignores the likelihood of large number of wells and pads being concentrated in certain areas, as well as construction noise from related infrastructure development (pipelines, compressors, etc.). The cumulative construction noise impact has not been addressed.

In addition, noise-related complaints are not the appropriate basis for drawing conclusions about the significance of noise impacts under SEQRA because people (and wildlife) can be adversely affected by noise, but choose not to report it. NYSDEC should evaluate the significance of the construction noise impacts in relation to the duration, quality (tonal purity), time of day and year, background noise present, distance to the source, familiarity with the noise and other factors such as the setting. Studies have shown that each listener’s subjective perception of appropriateness of a noise in a particular setting can be just as important to annoyance as the objective sound level.[1] Given the rural context of the majority of the areas where natural gas development is expected to occur, many residents and visitors to these areas would find heavy construction activity noise to be out of place and annoying. Construction noise adjacent to parks and other sensitive land areas where natural quiet is expected would be especially problematic and would contribute to adverse economic impacts not accounted

[1]See: Blauert, J. 1986. “Cognitive and Aesthetic Aspects of Noise Engineering.” In *Proceedings of Inter-Noise 86, Cambridge, Massachusetts, July 21–23*, volume 1, 5–13.

Kuwano, S., S. Namba, and H. Miura 1989 “Advantages and Disadvantages of A-weighted Sound Pressure Level in Relation to Subjective Impression of Environmental Noises.”*Noise Control Engineering Journal* 33:107–115.

Carles, J.L., I. Lopez Barrio, J.V. de Lucio 1999 “Sound Influence on Landscape Values.”*Landscape and Urban Planning* 43:191–200.
Ozawa, K., S. Ohtake, Y. Suzuki, and T. Sone 2003 “Effects of Visual Information on Auditory Presence,” Acoustical Letter to Acoustical Science and Technology, 24(2), 97-99.

for in the 2011 RDSGEIS by making areas where gas development is occurring less attractive to visitors.[2]

2.2 Drilling and Fracturing Impacts

2.2.1 Failure to Analyze Multi-Well Pad Impacts

The general approach used in the RDSGEIS quantitative noise impact assessment is reasonable and consistent with the methodology recommended in NRDC's comments on the 2009 DSGEIS for evaluation of the impacts of drilling and fracturing of one horizontal well. However, it fails to analyze the impacts of multi-well pads, which is the primary form of development anticipated. Table 6-59 in the RDSGEIS presents the duration of various construction and operational phases for one well. Each well is estimated to take 28-35 days to drill, while fracturing is assumed to take up to five days. Since drilling or fracking of multiple wells is likely to occur simultaneously, the combined noise levels would be higher than those reported for a single well in the RDSGEIS.

The failure of the RDSGEIS to provide a noise impact assessment for the simultaneous drilling and fracturing of multiple wells is especially problematic because it is inconsistent with the scenario developed for the analysis of transportation impacts (page 6-305). The result of this inconsistency is that the noise impacts of drilling and fracturing are underestimated and do not reflect a reasonably foreseeable worst-case development scenario. The multi-pad horizontal well development scenario in the transportation section of the RDSGEIS assumed three rigs would be operated simultaneously over a 120 day period and that each rig would drill four wells (for a total of 12 wells at the site). With three rigs in operation at the same time, the combined noise level at a distance of 50 feet would be approximately 84 dBA, not 79 dBA as reported for one rig in the RDSGEIS (Table 6.56- Rotary Air Well Drilling).[3]

With respect to the fracturing phase, the RDSGEIS wording is unclear, but appears to suggest sequential fracturing (one well being fractured at a time for a total of 60 days of fracturing noise impacts). The RDSGEIS states "fracturing and completion of the four wells occurs sequentially and tanks are brought in once for all four wells" (page 6-305). This statement is confusing because the scenario being described involves a total of 12 wells, not four wells. If fracturing of multiple wells occurs simultaneously, then the duration of fracturing impacts would be less, but the combined noise level would be higher. For example, fracturing two wells at once would create a combined noise level 3 dBA higher than the fracturing of one well. When drilling and fracturing are occurring at the same time, the total noise level would be entirely driven by the much louder fracturing process (no increase in the total sound level because the difference between the two sound levels is greater than 10 dBA).

At a minimum, NYSDEC should analyze the noise impact from the same multi-pad well development scenario as used in the analysis of transportation impacts. NYSDEC should address the expected number of wells per multi-well site, the timing of drilling and fracturing at each well and the reasonable worst case noise levels that could result from the various combinations of drilling and fracturing at multiple wells on the same site.

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[2] Refer to Susan Christopherson's socioeconomics technical memorandum for more information on impacts to the tourism industry.
[3] Decibels are expressed on a logarithmic scale and thus cannot be added together directly.

2.2.2 Lack of Reasonable Noise Impact Significance Criteria

Similar to the construction impact assessment discussed in Section 2.1, the RDSGEIS presents the model results for the drilling and fracturing noise impacts without a SEQRA-compliant assessment of the significance of the results in various contexts where natural gas development is anticipated. The RDSGEIS does not include noise impact criteria against which the significance of the impacts can be assessed generically or at the site specific review level, which is contrary to the purposes of a GEIS. For information on a recommended framework for developing noise impact criteria, refer to Section 2.8.

The RDSGEIS references NYSDEC's noise policy ("Assessing and Mitigating Noise Impacts,"2001)[4], but this document has a number of significant problems that limit its usefulness in regulating noise. It discusses a 6 dBA increase as potentially significant, but does not define what averaging time period should be used in calculating the increase, does not account for increased sensitivity to noise occurring at night, and does not take into account the total level at the affected receptor. The policy also does not provide a standard for specific highly sensitive land uses, such as passive recreation parks and wilderness areas. The NYSDEC noise policy leaves too much discretion to individual analysts to ensure consistent application of noise control for an activity expected to have widespread and significant impacts across New York. Accordingly, an assessment as to the significance of the potential adverse noise impacts should be made independent of the 2001 policy.

The RDSGEIS acknowledges that drilling and fracturing would take place 24hours per day. People are much more sensitive to noise that occurs at night and interferes with sleep than to noise that occurs only during daytime activities. For this reason, community noise impact assessment metrics such as day-night sound levels (Ldn) apply a 10 dB penalty to sounds occurring at night in determining a 24-hour average energy sound level that better reflects human preferences. Background noise levels are also lower at night, further emphasizing the significance of the increase in sound levels attributable to drilling and fracturing. As noted above in the discussion of construction impacts, non-residential land uses in rural areas vital to the economic health of upstate New York such as parks, recreation areas and campgrounds would be especially sensitive to increases in sound levels.

2.2.3 Fracturing Noise Impacts Exceed Hearing Damage Thresholds

The noise levels associated with the fracturing process are of a relatively short duration on a per well basis (2-5 days), but are of an extremely large magnitude that could adversely affect human health:

- At a distance of 2,000 feet, the fracturing pump truck noise level of up to 72 dBA would be intrusive and interfere with normal conversation.
- At a distance of 500 feet, the fracturing pump truck noise level of up to 84 dBA approaches the level where hearing damage occurs (85 dBA for eight hours).

[4] http://www.dec.ny.gov/docs/permits_ej_operations_pdf/noise2000.pdf

- At a distance of 250 feet, the fracturing pump truck noise level of up to 90 dBA is in the range of noise levels where no more than 15 minutes of unprotected exposure is recommended to prevent damage to hearing.[5]
- At a distance of 50 feet, the fracturing pump truck noise level of up to 104 dBA is of a similar magnitude to a jet flyover at a distance of 1,000 feet and at a level where unprotected exposure over one minute poses a risk of permanent hearing loss.

For context in understanding the sound levels discussed above, Table 1 provides a summary of the decibel level of common sounds sources and the associated effects.

Table 1
Decibel Levels of Common Sound Sources

Sound	Noise Level (dB)	Effect
Jet Engines (near)	140	
Shotgun Firing Jet Takeoff (100-200 ft.)	130	
Rock Concerts (varies)	110–140	Threshold of pain begins around 125 dB
Oxygen Torch	121	
Discotheque/Boom Box Thunderclap (near)	120	Threshold of sensation begins around 120 dB
Stereos (over 100 watts)	110–125	
Symphony Orchestra Power Saw (chainsaw) Pneumatic Drill/Jackhammer	110	Regular exposure to sound over 100 dB of more than one minute risks permanent hearing loss.
Snowmobile	105	
Jet Flyover (1000 ft.)	103	
Electric Furnace Area Garbage Truck/Cement Mixer	100	No more than 15 minutes of unprotected exposure recommended for sounds between 90–100 dB.
Farm Tractor	98	
Newspaper Press	97	
Subway, Motorcycle (25 ft.)	88	Very annoying
Lawnmower, Food Blender Recreational Vehicles, TV	85–90 70–90	85 dB is the level at which hearing damage (8 hrs.) begins
Diesel Truck (40 mph, 50 ft.)	84	
Average City Traffic Garbage Disposal	80	Annoying; interferes with conversation; constant exposure may cause damage
Washing Machine	78	
Dishwasher	75	
Vacuum Cleaner, Hair Dryer	70	Intrusive; interferes with telephone conversation
Normal Conversation	50–65	
Quiet Office	50–60	Comfortable hearing levels are under 60 dB.
Refrigerator Humming	40	
Whisper	30	Very quiet
Broadcasting Studio	30	
Rustling Leaves	20	Just audible
Normal Breathing	10	

Source: http://www.nidcd.nih.gov/health/education/teachers/pages/common_sounds.aspx

The minimum setbacks in the proposed regulations (currently 100 feet from a residence) must be revised to protect the health and well-being of nearby residents during fracking. Landowners should not have the power to waive the minimum setback requirement. The

[5] http://www.nidcd.nih.gov/health/education/teachers/pages/common_sounds.aspx

landowners should not be presented with the temptation to trade their family's health for financial gain. An additional problem with granting landowners the ability to waive setback requirements is that tenants of a landowner's property would not have any say in the landowner's decision to waive setback requirements essential for health.

The drilling phase sound levels are substantially lower than the fracturing noise levels, but their duration is much longer (approximately one month of 24-hour drilling per well). Drilling sound levels would drop to below 70 dBA at a distance of 250 feet from the well pad. However, 70 dBA is still 40 dBA greater than the nighttime background sound level in rural areas of 30 dBA, further supporting the need for noise impact criteria and mitigation requirements to protect the soundscapes of rural areas

2.2.4 Other Comments

Tables 6.56, 6.57 and 6.58 are all incorrectly labeled as showing "estimated construction noise levels."

The equipment assumed in the analysis and sound levels associated with each piece of equipment are based on "confidential industry sources." NYSDEC should disclose the basis for the equipment assumptions and sound levels so that these important inputs can be independently validated.

Table 6.57 has footnote "2" for the rig drive motor and generator sound levels, but the explanation for footnote 2 is missing. In addition, it appears that footnote #1 on Table 6.57 should be associated with the "Distance in Feet/SPL (dBA)" portion of the table and not the sound levels associated with the top drive, draw works and triple shaker.

2.3 Transportation Noise Impacts

The RDSGEIS discusses the potential for noise impacts related to truck traffic, but fails to conduct a meaningful analysis of typical transportation noise impacts for various phases of well pad development. This failure is particularly problematic given that the detailed truck trip generation information necessary for conducting a traffic noise assessment was developed for the transportation section of the RDSGEIS.

NYSDEC should use the Federal Highway Administration's (FHWA) Traffic Noise Model (TNM) version 2.5 and the truck trip generation information to fully consider truck traffic noise impacts. While site-specific impacts cannot be assessed, NYSDEC could easily examine a hypothetical, yet realistic development scenario for one well. The analysis could look at one single public road segment from which the well site would be accessed. Receptors at various distances (50 feet to 1,000 feet) would help show the potential extent of the area where impacts could occur. A range of non-natural gas related background traffic on the modeled road could be considered to show how the increase in sound levels would be much higher for local roads with low traffic volumes than for roads with high volumes under existing conditions. Traffic noise impacts for the various receptor distances could be assessed using well established New York State Department of Transportation (NYSDOT) and FHWA criteria.[6]

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[6]FHWA's noise impact assessment and mitigation procedures are defined under 23 CFR 772. NYSDOT's latest noise policy (revised April 2011) for implementing the FHWA requirements is

For the purposes of the SGEIS level of analysis, a number of simplifying, conservative assumptions could be employed in the TNM analysis (assuming flat terrain, no existing barriers, analyze one worst-case peak hour and one worst-case off-peak hour etc.). These assumptions would allow NYSDEC to complete a meaningful traffic noise analysis without extensive cost or delay to the review process.

2.4 Effects on Wildlife

Animals rely on sounds for communication, navigation, avoiding danger and finding food. Industrial and transportation noises associated with natural gas development create noise levels that can interfere with the sounds used by animals, which in turn can affect wildlife behavior and populations. The RDSGEIS acknowledges that noise could contribute to impacts on wildlife (page 6-68), but does not provide any analysis of this issue. NYSDEC should review the available scientific literature on this topic, qualitatively assess impacts and ensure appropriate mitigation measures are implemented. Key references to assist NYSDEC in this aspect of the environmental review are provided below:[7]

FHWA. Synthesis of Noise Effects on Wildlife Populations. http://www.fhwa.dot.gov/environment/noise/noise_effect_on_wildlife/effects/

Barber, J.R., K.R. Crooks, and K. Fristrup. 2010. The costs of chronic noise exposure for terrestrial organisms. Trends Ecology and Evolution 25(3): 180–189. Available at: http://www.sciencedirect.com/

Bayne, E.M., L. Habib and S. Boutin. 2008. Impacts of Chronic Anthropogenic Noise from Energy-Sector Activity on Abundance of Songbirds in the Boreal Forest. Conservation Biology 22(5) 1186-1193. Available at: http://oz.biology.ualberta.ca/faculty/stan_boutin/uploads/pdfs/Bayne%20etal%202008%20ConBio.pdf

Dooling R. J., and A. N. Popper. 2007. The effects of highway noise on birds. Report to the California. Department of Transportation, contract 43AO139. California Department of Transportation, Division of Environmental Analysis, Sacramento, California, USA. Available at: http://www.dot.ca.gov/hq/env/bio/files/caltrans_birds_10-7-2007b.pdf

Francis, C.D., C.P. Ortega and A. Cruz. 2009. Noise Pollution Changes Avian Communities and Species Interactions. Current Biology, Aug 25;19(16):1415-9 10.1016/j.cub.2009.06.052. Available at: http://www.sciencedirect.com/science/article/pii/S0960982209013281

Habib, L, E.M. Bayne and S. Boutin. 2007. Chronic industrial noise affects pairing success and age structure of ovenbirds Seiurus aurocapilla. Journal of Applied Ecology 44: 176-184. Available at: http://oz.biology.ualberta.ca/faculty/stan_boutin/ilm/uploads/pdfs/Habib%20etal%202

available at https://www.dot.ny.gov/divisions/engineering/environmental-analysis/manuals-and-guidance/epm/repository/4_4_18Noise.pdf

[7] The suggested list of references is adapted from the USFWS paper entitled "The Effects of Noise on Wildlife." Available at: http://www.fws.gov/windenergy/docs/Noise.pdf

007%20JAE.pdf

Schaub, A, J. Ostwald and B.M. Siemers. 2008. Foraging bats avoid noise. The Journal of Experimental Biology 211: 3174-3180. Available at: http://jeb.biologists.org/cgi/content/full/211/19/3174

Swaddle, J.P. and L.C. Page. 2007. High levels of environmental noise erode pair preferences in zebra finches: implications for noise pollution. Animal Behavior 74: 363-368.

2.5 Cumulative Impacts

The RDSGEIS does not address the cumulative noise impacts of the anticipated natural gas development. Key considerations in developing a cumulative impact analysis for noise include the following:

- Analyze the cumulative noise impact of multi-well pads. The RDSGEIS analysis only addresses a single well.
- Analyze the cumulative noise impact from well site construction, drilling and fracturing in combination with the construction of pipelines and the operation of compressor stations. Pipelines and compressor stations are a reasonably foreseeable form of "induced growth" that needs to be considered.
- Examining the Ldn sound levels that would result at residences that are exposed to drilling, fracturing and truck traffic noise. The combination of these sources could result in impacts more significant than any individual source examined separately.
- Discuss regional-scale traffic noise impacts that would result from wide spread natural gas development and related economic development and temporary population growth.
- Discuss regional-scale noise impacts on human beings and wildlife, including the potential for disturbance of noise-sensitive species, such as the ovenbird (*Seiurus aurocapilla*).[8]

2.6 Mitigation

2.6.1 Mitigation for Construction Impacts

Construction noise impact mitigation is not addressed in Section 7.10 of the RDSGEIS. NYSDEC should require the use of construction noise mitigation best practices, such as those outlined in FHWA's Construction Noise Handbook. At a minimum, these measures should include:

- Requiring the use of construction noise control measures in construction contract documents. Specific noise levels can be established to ensure the protection of sensitive receptors.

[8] http://oz.biology.ualberta.ca/faculty/stan_boutin/ilm/uploads/pdfs/Habib%20etal%202007%20JAE.pdf

- Limitations on the time periods when construction could occur (e.g., prohibiting nighttime construction).
- Requiring the use of less noisy equipment and mufflers.
- Requiring temporary noise barriers when significant impacts cannot be addressed through other means.

2.6.2 Mitigation for Drilling, Fracturing and Transportation Impacts

The general types of noise mitigation measures for drilling, fracturing and trucking suggested in the RDSGEIS are reasonable, but there is no guarantee which measures, if any, will actually be required in specific circumstances. Therefore, it is likely that significant impacts will not be mitigated at the site level. In addition, the RDSGEIS states that detailed noise modeling and consideration of mitigation measures will only be required for receptors within 1,000 feet of the well pad. This requirement is illogical given the impact analysis results that show impacts extending beyond 2,000 feet. Under NYSDEC's proposed 1,000 feet distance for noise modeling, well operators could avoid assessing site specific impacts and mitigation by locating wells just beyond the 1,000 feet threshold. This could result in unmitigated significant adverse impacts for residences between 1,000 and 2,000+ feet from the well pad.

Table 2 summarizes the noise mitigation commitments in the RDSGEIS and shows that many of these commitments were not carried through to the EAF, EAF Addendum or the proposed regulations. The mitigation measures not included in the EAF or regulations are not enforceable.

The proposed supplemental permit conditions (Appendix 10) state that NYSDEC can require noise mitigation "deemed necessary," but this is meaningless without a clear basis for determining when noise impacts that warrant mitigation occur. The proposed supplemental permit conditions do not contain any of the mitigation measures in Table 2 that were not addressed by the EAF or the regulations. The proposed supplemental permit conditions do contain specific requirements to mitigate air quality impacts (Appendix 10, Attachment A), therefore it would be reasonable and consistent to also include many of the site-specific noise mitigation measures in Table 2 as supplemental permit conditions. A few of the mitigation measures in Table 2 are general enough that they should be incorporated in the proposed regulations, rather than as supplemental permit conditions. These are indicated in the "notes" column of Table 2.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate noise impacts at HVHF sites, and use this information to refine the noise mitigation requirements for future permit applications.

Table 2
Noise Mitigation Matrix

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated into Supplemental Permit Conditions	Notes
Compliance with regulatory spacing and siting restrictions. (7-128)	No	Yes (553.1)	No	
Unless otherwise required by private lease agreement, the access road must be located as far as practicable from occupied structures, places of assembly, and occupied but unleased property. (7-135)	Yes (A6-6)	Yes (560.6(a))	No	Regulation adds an additional qualifier where this provision potentially does not apply- to avoid bisecting agricultural land.
The well operator must operate the site in accordance with a noise impacts mitigation plan consistent with the SGEIS. (7-135)	Yes (A6-6)	No	No	Applies to all wells, should be in regulations
The operator's noise impacts mitigation plan shall be provided to the Department along with the permit application. (7-135)	Yes (A6-5)	No	No	Applies to all wells, should be in regulations
Additional site-specific noise mitigation measures will be added to individual permits if a well pad is located within 1,000 feet of occupied structures or places of assembly. (7-135)	Partial(A6-5)	No	No	Permit applicants are required to identify mitigation measures in the noise mitigation plan, but there is no regulatory requirement that mitigation is included in permit conditions. Applies to all wells, should be in regulations
Modifying speed limits or restricting truck traffic on certain roads. (7-130)	No	No	No	
Noise modeling for any site within 1,000 feet of a noise receptor. (7-130)	No (noise mitigation plan is required, modeling is not mentioned)	No	No	The 1,000 feet distance is arbitrary and inconsistent with the 2011 RDSGEIS analysis results which show significant impacts out to 2,000+ feet from the well pad. Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated into Supplemental Permit Conditions	Notes
Potential site-specific permit condition: Requiring the measurement of ambient noise levels prior to beginning operations. (7-130)	No	No	No	All of the following site specific measures are required "as practicable," but no procedure or criteria for determining practicability is specified.
Potential site-specific permit condition: Specifying daytime and nighttime noise level limits as a permit condition and periodic monitoring thereof. (7-130)	No	No	No	Daytime and nighttime noise limits should be established as part of the SGEIS and regulatory process, not on a permit by permit basis that does not allow for public review. The noise limits should be consistent and included in regulations.
Potential site-specific permit condition: Placing tanks, trailers, topsoil stockpiles, or hay bales between the noise sources and receptors. (7-131)	No	No	No	
Potential site-specific permit condition: Using noise-reduction equipment such as hospital-grade mufflers, exhaust manifolds, or other high-grade baffling. (7-131)	No	No	No	
Potential site-specific permit condition: Limiting drill pipe cleaning ("hammering") to certain hours .(7-131)	No	No	No	
Potential site-specific permit condition: Running of casing during certain hours to minimize noise from elevator operation. (7-131)	No	No	No	
Potential site-specific permit condition: Placing air relief lines and installing baffles or mufflers on lines. (7-131)	No	No	No	
Potential site-specific permit condition: Limiting cementing operations to certain hours (i.e., perform noisier activities, when practicable, after 7 A.M. and before 7 P.M.). (7-131)	No	No	No	
Potential site-specific permit condition: Using higher or larger-diameter stacks for flare testing operations. (7-131)	No	No	No	

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated into Supplemental Permit Conditions	Notes
Potential site-specific permit condition: Placing redundant permanent ignition devices at the terminus of the flow line to minimize noise events of flare re-ignition. (7-131)	No	No	No	
Potential site-specific permit condition: Providing advance notification of the drilling schedule to nearby receptors. (7-131)	No	No	No	
Potential site-specific permit condition: Placing conditions on air rotary drilling discharge pipe noise, including: -orienting high-pressure discharge pipes away from noise receptors; - having the air connection blowdown manifolded into the flow line. This would provide the air with a larger-diameter aperture at the discharge point; - having a 2-inch connection air blowdown line connected to a larger-diameter line near the discharge point or manifolded into multiple 2-inch discharges; - shrouding the discharge point by sliding open-ended pieces of larger-diameter pipe over them; or -rerouting piping so that unusually large compressed air releases (such as connection blowdown on air drilling) would be routed into the larger-diameter pit flow line to muffle the noise of any release. (7-131)	No	No	No	
Potential site-specific permit condition: using rubber hammer covers on the sledges when clearing drill pipe. (7-131)	No	No	No	
Potential site-specific permit condition: Laying down pipe during daylight hours. (7-131)	No	No	No	
Potential site-specific permit condition: Scheduling drilling operations to avoid simultaneous effects of multiple rigs on common receptors. (7-131)	No	No	No	
Potential site-specific permit condition: Limiting hydraulic fracturing operations to a single well at a time. (7-131)	No	No	No	
Potential site-specific permit condition: Employing electric pumps. (7-131)	No	No	No	

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated into Supplemental Permit Conditions	Notes
Potential site-specific permit condition: Installing temporary sound barriers (see Photo 7.2, Photo 7.3, and Photo 7.4) of appropriate heights, based on noise modeling, around the edge of the drilling location between a noise generating source and any sensitive surroundings. Sound control barriers should be tested by a third-party accredited laboratory to rate Sound Transmission Coefficient (STC) values for comparison to the lower-frequency drilling noise signature. (7-131)	No	No	No	

2.7 EAF and EAF Addendum

The EAF requires land use information for a distance of one-quarter (1/4) mile around the well pad. This distance is insufficient, as many impacts (including noise and visual) extend far beyond this distance. The EAF should require the identification and mapping of land uses within one mile of the well pad, as well as additional land use mapping along local roads that would be affected by heavy truck traffic (as identified in the required transportation plan) outside the one mile area. The EAF Addendum should specifically require the identification of land uses that are especially sensitive to noise, including protected open space, recreational areas, places of worship, campgrounds, hotels, schools, and healthcare facilities.

The details of the noise mitigation plan required by the EAF Addendum are not sufficiently defined to ensure impacts are mitigated. There is a need for a standardized noise impact assessment procedure and criteria for determining the reasonableness of various levels of mitigation expenditure (e.g., the cost per benefited receptor approach used by DOTs). Without standardized requirements for assessing and mitigating noise impacts, residents in areas affected by gas development will not receive fair or consistent treatment. The NYSDEC noise guidance document does not provide sufficient detail and criteria to ensure appropriate noise analyses conducted at the site level. At a minimum, NYSDEC should provide the detailed requirements of the noise mitigation plan, addressing the following components:

- Scope of study area for the mitigation plan (recommend one-half (1/2) mile around well pad plus sensitive areas adjacent to the local roads that would experience the largest percent increase in truck traffic).
- Methodology for establishing existing noise levels (recommend requiring 24-hour measurements at a few representative receptors).
- Required protocol for assessing noise impacts: what noise metrics should be used (Ldn, Lmax, peak hour Leq, percent time audible etc.); what sources need to be considered (transportation, drilling and fracking); acceptable software modeling packages; and sources of information on appropriate sound emission levels to assume for various types of the equipment.
- Required criteria for determining which impacts are significant and require mitigation and which do not.
- Required criteria for determining how much expenditure on mitigation is reasonable to address significant adverse impacts.

One template for NYSDEC to consider adopting to specify the requirements of noise impact analysis and mitigation plans is the Alberta Energy Resources Conservation Board (ERCB) Noise Control Directive (#38), which is described below in Section 2.8.

2.8 Best Practice Recommendation for Noise Standards and Site-Specific Impact Assessment Protocol

The Alberta ERCB Noise Control Directive was developed through an extensive scientific review process and is recognized as one of the most stringent in the world. The Noise Control directive is based on the calculation of a permissible sound level (PSL) at the worst case receptor in terms of equivalent energy sound level (Leq)[9] for the daytime period and the nighttime period. The PSL calculation takes into account all the important factors that influence human annoyance due to noise:

- Daytime noise is allowed to be higher than nighttime noise, reflecting the greater sensitivity to noise occurring at night.
- Existing noise levels are taken into account based on dwelling unit densities and transportation infrastructure or through ambient monitoring.
- A sliding scale of adjustment factors based on the duration of the noise accounts for the fact that people are more tolerant of a brief period of noisy activity than a noise source that continues for months or years.

As a simple example, the PSL in a low density rural area not near a major transportation corridor would be calculated as follows for the drilling of one well (35 days):

Nighttime Drilling PSL= 40 dBA basic sound level + 5 dBA adjustment due to the duration
Nighttime Drilling PSL= 45 dBA

The daytime PSL for drilling in this simple example would be 10 dBA higher, or 55 dBA.

For five days of fracking, the PSL in a low density rural area not near a major transportation corridor would be calculated as follows:

Nighttime Fracking PSL= 40 dBA basic sound level + 10 dBA adjustment due to the duration
Nighttime Fracking PSL= 50 dBA

The daytime fracking PSL would be 10 dBA higher or 60 dBA. This daytime limit would be exceeded even at a distance of 2,000 feet from the well pad based on the RDSGEIS analysis without mitigation, which estimated 72 dBA at this distance, or approximately twice as loud as the standard.

The Alberta ERCB Noise Control Directive also outlines detailed requirements to standardize the modeling of noise impacts and the preparation and documentation of noise studies that would be appropriate for NYSDEC to consider in regulating noise from HVHF in New York.

3.0 Ground-Borne Vibration and Noise

Page 6-251 of the RDSGEIS acknowledges the potential for ground-borne vibration impacts in the discussion of potential effects on property values: “Gas well development could impact local environmental resources and cause noise and vibration impacts, and trucks servicing the well development could also impact the surrounding areas.” Despite this statement, no vibration impact analysis (or an explanation of why an analysis was not conducted) is presented in the 2011 RDSGEIS. NYSDEC should analyze vibration impacts addressing the following issues:

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[9] Leq refers to the constant sound level that conveys the same energy as the variable sound levels during the analysis period.

- Construction-period vibration impacts for access road and well pad development. Recommended procedures are provided in Section 12.2 of the Federal Transit Administration's *Transit Noise and Vibration Impact Assessment* guidebook. A simple qualitative assessment may be appropriate in this case. While construction activities do not typically create vibration levels capable of damaging most buildings, fragile historic buildings are more sensitive and should be avoided in the siting of access roads and well pads. Ground vibration from construction can also be an annoyance to adjacent land uses.

- Operation vibration impacts associated with drilling and fracking. This assessment should include information on drilling vibration levels from existing natural gas development in New York and other locations. While it is difficult to generalize vibration effects from one area to another due to the effects of local soils and geologic conditions, this information would provide a rational basis for identifying a screening distance for determining when a more detailed vibration impact assessment should be required at the site level. If no receptors are within the screening distance at which perceptible vibration levels could occur, then no vibration assessment would be required in the site level review.

- Operation low-frequency ground-borne noise impacts. Ground vibration can create a phenomenon known as ground-borne noise, a rumble associated with the movement of the interior surfaces of a room.[10] Special considerations apply when assessing low-frequency noise because of the non-linearity of human hearing which causes sounds dominated by low-frequency components to seem louder than broadband sounds that have the same A-weighted level. As a result, even low levels of low-frequency noise (generally defined as the frequency range below 200 Hz) can be perceived as highly annoying and contribute to sleep problems and other health problems caused by sleep disruption. In addition to sleep disturbance and physiological stress, there is strong evidence that noise exposure can contribute to cardiovascular diseases.[11] NYSDEC should assess the potential for the various phases of well development and production to generate ground-borne noise, including any on-site equipment such as condensers that have been anecdotally reported generating high vibration levels in Pennsylvania.

Based on the ground-borne noise and vibration impact assessment conclusions, the NYSDEC should identify ground-borne noise and vibration impact mitigation measures and ensure that information necessary to identify and mitigate ground-borne noise and vibration impacts at the site level is required as part of the EAF Addendum, supplemental permit conditions and/or regulations.

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[10]Both ground-borne noise and vibration are issues associated with the inside of buildings and are generally not annoying outdoors.
[11] See Cardiovascular effects of noise. Noise Health. Vol. 15 Issue 52. http://www.noiseandhealth.org/showBackIssue.asp?issn=1463-1741;year=2011;volume=13;issue=52;month=May-June

4.0 Visual

4.1 Impact Assessment

The RDSGEIS describes in very broad terms the potential direct and cumulative impacts of various phases of natural gas development on NYSDEC-designated visually sensitive resources. The RDSGEIS considers and incorporates information from two studies by others that addressed the visual impact of high-volume hydraulic fracturing.[12] The public disclosure of significant adverse visual resource impacts should be improved by providing the following:

- Discussion of the various viewer groups (local residents, through travelers, tourists, etc.) that would experience changed views as a result of natural gas development and their relative sensitivity. For example, local residents are familiar with local views and may be very sensitive to changes in views they consider important. Tourists visiting an area in part to experience high visual environment quality would also be much more sensitive than general through travelers that would have passing views of natural gas development from roadways while commuting. NYSDEC should describe how natural gas development at the scale anticipated in the socioeconomic impact study would affect viewer perceptions.

- To aid in the identification and understanding of impacts, landscape similarity zones (rural open areas, rural wooded areas, villages, cities, etc.) should be identified statewide and computer modeling conducted to create three dimensional photo simulations of various phases of the well development process at various distances for each zone. NYSDEC would not need to develop this analysis from scratch—significant consultant costs could be saved by using the New York State Office For Technology's "Generic Visual Impact Assessment" prepared for the 2004 Statewide Wireless Network (SWN) DGEIS as a starting point.[13] The SWN Generic Visual Impact Assessment is an excellent example for NYSDEC to follow in comprehensively addressing visual impacts at the GEIS stage. The landscape similarity zones and representative photos selected for photo simulations used in the SWN analysis could likely be used with no to little modification. The main additional work required would be to define the components of a typical well pad development at various phases in sufficient detail and re-run the simulation model.

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[12]Upadhyay and Bu. 2010. Visual Impacts of Natural Gas Drilling in the Marcellus Shale Region. Cornell University, Dept. of City and Regional Planning: CRP 3072 Land Use, Environmental Planning, and Urban Design Workshop

Rumbach, Andrew. 2011. Natural Gas Drilling in the Marcellus Shale: Potential Impacts on the Tourism Economy of the Southern Tier

[13]New York State Office for Technology. 2004. *Draft Generic Environmental Impact Statement for the New York State Statewide Wireless Network*. Cultural Resources Appendix B. Prepared by Environmental Design & Research, P.C. (now EDR Companies)

- Analysis of light pollution impacts of nighttime lighting and flaring. The RDSGEIS analysis focuses on daytime visual impacts and downplays nighttime light impacts as a "temporary impact" that most of the viewing public would not be exposed to (see page 6-281). Light pollution impacts would not be temporary when the duration of drilling, fracturing and production activities is considered for multi-well pads and cumulatively as numerous well pads are added throughout the region over the 60 year development timeframe contemplated in the RDSGEIS. The RDSGEIS ignores the visual impact to local residences that comes with the loss of pristine dark nighttime skies in rural areas. Residences are not even mentioned in the impact assessment. In many cases the nighttime impact will be more significant than the daytime visual impact because the lighting will make the well site a pronounced focal point. In addition to evaluating the visual impact of light pollution on humans, NYSDEC also needs to evaluate the impact of nighttime lighting and flaring on migratory birds.[14]

The photographs of a PA well site below illustrate the dramatic visual impact of natural gas development in a rural residential setting during the day and night.

[14] Poot, H., B. J. Ens, H. de Vries, M. A. H. Donners, M. R. Wernand, and J. M. Marquenie. 2008. Green light for nocturnally migrating birds. *Ecology and Society* **13**(2): 47. http://www.ecologyandsociety.org/vol13/iss2/art47/
For background information on light pollution impacts on wildlife see: http://www.darksky.org/index.php?option=com_content&view=article&id=719


Day and Night Views of Chappel Unit 1H-10H in Hopewell Township, Washington County PA. Source: http://www.marcellus-shale.us/Chappel-Unit.htm

4.2 Mitigation

The RDSGEIS mitigation section for visual resources suggests that mitigation measures would only be considered when designated significant visual resources (parks, historic resources, scenic rivers, etc.) are present and within the viewshed of proposed wells. This approach fails to consider visual impacts on nearby residences or tourists in areas where a significant visual resource is not present. In these situations, no mitigation would be required for individual wells to be consistent with the RDSGEIS. NYSDEC should make basic and low-cost mitigation measures mandatory for all well development sites (such as keeping lighting levels at the minimum level required and directing lights downward to minimize light pollution), regardless of whether or not significant visual resources are present. In addition, a broader menu of more sophisticated and costly mitigation measures should be provided for those development sites that do have the potential to impact designated visual resources.

Table 3 summarizes the visual impact mitigation commitments in the RDSGEIS and shows that many of these commitments were not carried through to the EAF, EAF Addendum, regulations or supplemental permit conditions. The mitigation measures not included in the EAF, regulations or permit conditions are not enforceable. The proposed supplemental permit conditions do contain specific requirements to mitigate air quality impacts (Appendix 10, Attachment A); therefore it would be reasonable and consistent to also include many of the visual impact mitigation measures in Table 3 as supplemental permit conditions. A few of the visual impact mitigation measures that are general enough and are applicable to all well sites should be incorporated into the proposed regulations. These mitigation measures are identified in the notes column of Table 3.

Table 3
Visual Impacts Mitigation Matrix

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Prepare visual impacts mitigation plan (A6-6 and Supplemental Permit Conditions).	**Yes**	No	**Yes**	Applies to all wells, should be in regulations
Flaring would only occur during initial flowback at some wells, and the potential for flaring would be limited to the extent practicable by permit conditions, such that the duration of nighttime impacts from flaring typically would not occur for longer than three days. (6-281)	No	No	No	Applies to all wells, should be in regulations
The development of measures to reduce impacts on visual resources or visually sensitive areas would follow the procedures identified in NYSDEC DEP-00-2, “Assessing and Mitigating Visual Impacts.” (7-121)	No	No	No	Applies to all wells, should be in regulations
Design and siting measures, as described in NYSDEC DEP-00-2, would typically consist of screening, relocation, camouflage or disguise, maintaining low facility profiles, downsizing the scale of a project, using alternative technologies, using non-reflective materials, and controlling off-site migration of lighting (NYSDEC 2000). (7-122)	No	No	No	Design and siting mitigation measures would be primarily site specific, but some measures could be incorporated in regulations (see the mitigation measure below regarding avoiding ridgelines and minimizing light pollution).
Relocating well sites to avoid ridgelines or other areas where aboveground equipment and facilities breaks (sic) the skyline; and minimizing off-site light migration by using night lighting only when necessary and using the minimum amount of nighttime lighting necessary, directing lighting downward instead of horizontally, and using light fixtures that control light to minimize glare, light trespass (off-site light migration), and light pollution (sky glow). (7-125)	No	No	No	Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
The study also recommends the development of a best practices manual for Department staff and the industry, which would provide information on what is expected by the Department in terms of well siting and visual mitigation, and the identification of instances where visual mitigation may be necessary. (7-126)	No	No	No	
Develop a feedback mechanism in the project review process to confirm the success of measures to avoid, minimize, or mitigate visual impacts, based on the analysis of results for prior projects. (7-126)	No	No	No	
The maintenance activities described in NYSDEC DEP-00-2 should be implemented to prevent project facilities from becoming "eyesores." Such measures would typically consist of appropriate mowing or other measures to control undesirable vegetation growth; erosion control measures to prevent migration of dust and/or water runoff from a site; measures to control the off-site migration of refuse; and measures to maintain facilities in good repair and as organized and clean as possible according to the type of project. (7-126)	No	Partial- mostly related to stormwater and erosion control	Partial- SWPPP required	Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
The decommissioning activities described in NYSDEC DEP-00-2 should be implemented when the useful life of the project facilities is over; these activities would typically occur during the reclamation phase for well sites. Such activities would typically consist of, at a minimum, the removal of aboveground structures at well sites. Additional decommissioning activities that may also be required include: the total removal of all facility components at a well site (aboveground and underground) and restoration of a well site to an acceptable condition, usually with attendant vegetation and possibly including recontouring to reestablish the original topographic contours; the partial removal of facility components, such as the removal or other elimination of structures or features that produce visual impacts (such as the restoration of water impoundment sites to original conditions); and the implementation of actions to maintain an abandoned facility and site in acceptable condition to prevent the well site from developing into an eyesore, or prevent site and structural deterioration. (7-127)	Partial- site reclamation plans required, but no specific measures are required.	Partial (560.7 Reclamation)	Partial (reclamation plans required)	
The offsetting mitigation described in NYSDEC DEP-00-2 should be implemented when the impacts of well sites on visual resources or visually sensitive areas are significant and when such impacts cannot be avoided by locating the well pad in an alternate location. Per guidance in NYSDEC DEP-00-2, offsetting mitigation would consist of the correction of an existing aesthetic problem identified within the viewshed of a proposed well project. (7-128)	No	No	No	

4.3 EAF and EAF Addendum

There are a number of problems with the EAF and EAF Addendum requirements as currently drafted that will result in significant unmitigated adverse visual impacts if not corrected.

The EAF does not require sufficient information to properly identify receptors that would experience views of proposed wells. The EAF requirement is to identify the distance to the closest occupied building or outdoor facility. The EAF Addendum requires identification of "[a]ll residences, occupied structures or places of assembly within 1,320 feet." This is not a sufficient distance for assessing visual impacts and does not take into account the fact that the closest structures may not be the most impacted depending on local vegetation and topography patterns.[15] A more reasonable distance for identifying sensitive resources and receptors in most instances would be one mile.[16] The EAF addendum should require a visibility analysis to determine where the well site facilities would be visible from public roadways, parks, residences and other sensitive receptors. The number of viewers exposed and the activities viewers would typically be engaged in during exposure needs to be evaluated to determine the extent of visual impacts and the need for mitigation at the site level. NYSDEC has developed excellent guidance on this topic ("Assessing and Mitigating Visual Impacts") and a useful visual EAF addendum. These best practice approaches to visual impact assessment and mitigation should be required as part of the EAF for proposed well development sites.

Unlike the noise and traffic mitigation plans, a visual impacts mitigation plan is not a required component of the submittals to NYSDEC with the permit application, EAF and EAF Addendum. The visual impacts mitigation plan does not even have to be prepared prior to issuance of the well drilling permit and is not subject to prior approval by NYSDEC. The only apparent requirement is that the visual resource mitigation plan is prepared by the applicant in conformity with the SGEIS and made available to the NYSDEC on request. This procedure offers no opportunity for public review or even notice to affected local residents. A visual resources mitigation plan that is not subject to public review and that does not require NYSDEC approval is not an adequate mitigation measure.

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[15]The RDSGEIS acknowledges that on-site equipment would be a prominent landscape feature at distances of up to double 1,320 feet used in the EAF Addendum. Page 6-274: "On-site equipment would be the most visible sign of fracturing activity and, when viewed from relatively short distances (i.e., from 1,000 feet to 0.5 miles) are relatively prominent landscape features."

[16] Although drilling activity during the daytime would be most prominent within ½ mile, a one mile distance is reasonable to account for areas with topography that could make well sites prominent features for more distant views and to address nighttime lighting impacts (which could be prominent at greater distances than the physical appearance of the well site equipment during the day.

5.0 Land Use

5.1 Impact Assessment

The RDSGEIS fails to provide any analysis of the reasonable foreseeable cumulative land use impacts that would result if high-volume hydraulic fracturing was permitted in New York. To comply with SEQRA, NYSDEC should provide the following information:

- An overview of statewide existing land uses patterns and land use planning framework. Much of this information and mapping could be adopted directly from Section 3.3.2.2 of the 2004 Statewide Wireless Network DGEIS and associated appendices. This would provide an appropriate baseline to use in assessing potential land use impacts.

- A quantitative analysis of potential land cover change at the county level. This analysis could use readily available GIS land cover data for existing conditions and assume that well development would impact land cover proportionate to the existing percentage of land cover types in each county (excluding water and developed land). Impacts could be assessed using the average 7.4 acres of disturbance per multi-well pad used in the RDSGEIS (page 5-6) and an estimate of the number of well pads by county consistent with the economic impact study county-level estimates. Cumulative impacts associated with existing trends and known major development proposals should be evaluated, taking into account the lack of capacity of rigorous land use regulation throughout most rural areas of the Southern Tier.

- A qualitative assessment of the compatibility of natural gas development with various adjacent land uses, taking into consideration impacts associated with truck traffic, noise and visual impacts. Appropriate buffer zones should be recommended between natural gas development and incompatible land uses such as residences, parks and schools to minimize impacts.

- A qualitative assessment of the consistency of natural gas development with local and regional plans. Specific land use plans and zoning regulations could not be analyzed in detail in a GEIS, but generalized planning areas common to many areas of the Marcellus shale region could be considered (e.g., rural residential, agricultural, commercial, etc.). Natural gas development should not be permitted to undermine local land use laws, especially planning in rural areas that emphasizes resource protection, open space, and scenic quality. Potential inconsistencies with plans prepared pursuant to New York's Local Waterfront Revitalization Program should be specifically considered in this assessment.

The failure of the RDSGEIS to analyze land use impacts is inconsistent with the scope for the SGEIS, which included a commitment to conduct an "[e]valuation of whether any aspect of multi-well site development or high-volume hydraulic fracturing of shale wells could be expected to change the GEIS's conclusion that major long-term changes to land use patterns, traffic and the need for public services are not anticipated as the result of gas well development. This will include review of the compatibility of shale gas development with other land uses such as agriculture, tourism, and alternative energy development."[17] The RDSGEIS is deficient because it does not contain a land use impact assessment addressing compatibility with agriculture, tourism, and alternative energy development.

5.2 Mitigation

The RDSGEIS fails to provide any discussion of mitigation measures for land use impacts. Based on the additional analyses of land use impacts recommended above, mitigation measures such as buffer distances for incompatible land uses should be described and incorporated into enforceable regulations or supplemental permit conditions, as appropriate. The RDSGEIS should make it clear that such mitigation measures are intended to supplement any local zoning or other land use planning addressing the location of industrial uses, including gas development.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate land use impacts at HVHF sites, and use this information to refine the land use mitigation requirements for future permit applications.

5.3 EAF and EAF Addendum

The topic of consistency with local plans was not addressed in the EAF and EAF Addendum in the 2009 DSGEIS. The addition of a requirement related to the review of local plans and assessment of consistency as part of the EAF Addendum in the RDSGEIS is an improvement. The term "land use plan" should be broadly defined in the EAF Addendum to ensure it encompasses comprehensive plans, zoning ordinances, subdivision regulations, site plan review requirements, hazard mitigation plans, open space plans, agricultural/farmland protection plans, Local Waterfront Revitalization Program plans, historic districts/historic resource protection plans, economic revitalization and tourism plans, ecological and water resource protection/restoration plans etc.

With respect to the avoidance of land use compatibility impacts, the requirements of the EAF Addendum in the RDSGEIS remain extremely vague. Permit applicants are required to attest that "[u]nless otherwise required by private lease agreement, the access road will be located as far as practical from occupied structures, places of assembly and unleased property." There are no definitional or other criteria for determining what is "as far as practical" concerning location of the access road in relation to occupied structures, places of assembly and unleased property. Nor is there any required explanation by the applicant to support its affirmation or submission of a map showing such structures and uses in relation to the access road. Nor is there any required hierarchy in determining which uses of land require greatest distance from the access road in the event that movement of the access road away from one use would bring it closer to another. All that is required of the applicant is a bare affirmation that it has located the access road.

[17] NYSDEC. 2009. *Scope for the 2009 Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program*. Page 41

The EAF Addendum requires the identification of “[a]ll residences, occupied structures or places of assembly within 1,320 feet.” However, as noted previously, there is evidence that significant impacts (such as noise) extend beyond 1,320 feet. In order to comply with SEQRA, NYSDEC must require that the applicant identify all land uses within one mile of a proposed well. These land uses should include, but not be limited to hospitals, senior citizen residences, schools, places of worship, and residential uses.

6.0 Transportation

6.1 Impact Assessment

Additional analysis is provided in the RDSGEIS regarding truck trip generation (e.g., the number of truck trips to and from the well site at varies stages), but the impact on roadway congestion and safety has not been adequately addressed. The impacts of a typical multi-well development on congestion and safety should be analyzed in detail, as well as a cumulative traffic effects analysis using a reasonable worst case development scenario. The reasonable worst case development scenario for regional traffic impacts should include indirect traffic generation associated with increased economic development and population growth attributable to natural gas extraction and related industries. Finally, the statewide impact on vehicle miles traveled (VMT) should be reported, taking into account the long distance truck trips that would be required to haul produced water and brine waste out of state for disposal.

6.1.1 Traffic Congestion and Safety Impacts of a Typical Multi-Well Pad

The detailed analysis of the traffic congestion and safety impacts of one typical multi-well pad development serves an important purpose in terms of disclosing the general types of impacts that could occur in many similar locations, but also in terms of creating an analysis template for permit applicants to follow in developing their transportation plans for specific development proposals. A hypothetical well site could be identified in the area where the greatest drilling is expected (Region A) or an actual well site in an area of Pennsylvania representative of similar areas in New York could be analyzed. Once the hypothetical or actual well site is located, the following tasks should be undertaken:

- Identification of the project area where transportation impacts would be most likely based on actual or hypothetical information on trip origins and routes for workers, equipment and water deliveries to the site.
- Characterization of existing conditions in the project area using NYSDOT traffic counts, local data and additional traffic counts as needed. Topics to be addressed should include traffic volumes, intersection level of service, crash rates, etc.
- Analysis of impacts on traffic volumes, intersection congestion and safety consistent with the 2010 Highway Capacity Manual, NYSDOT procedures for traffic impact assessment and good transportation engineering practice.
- Development of mitigation measures to address significant impacts, such as changes in signal timing, temporary traffic signals, limitations on the routes used by water trucks, etc.

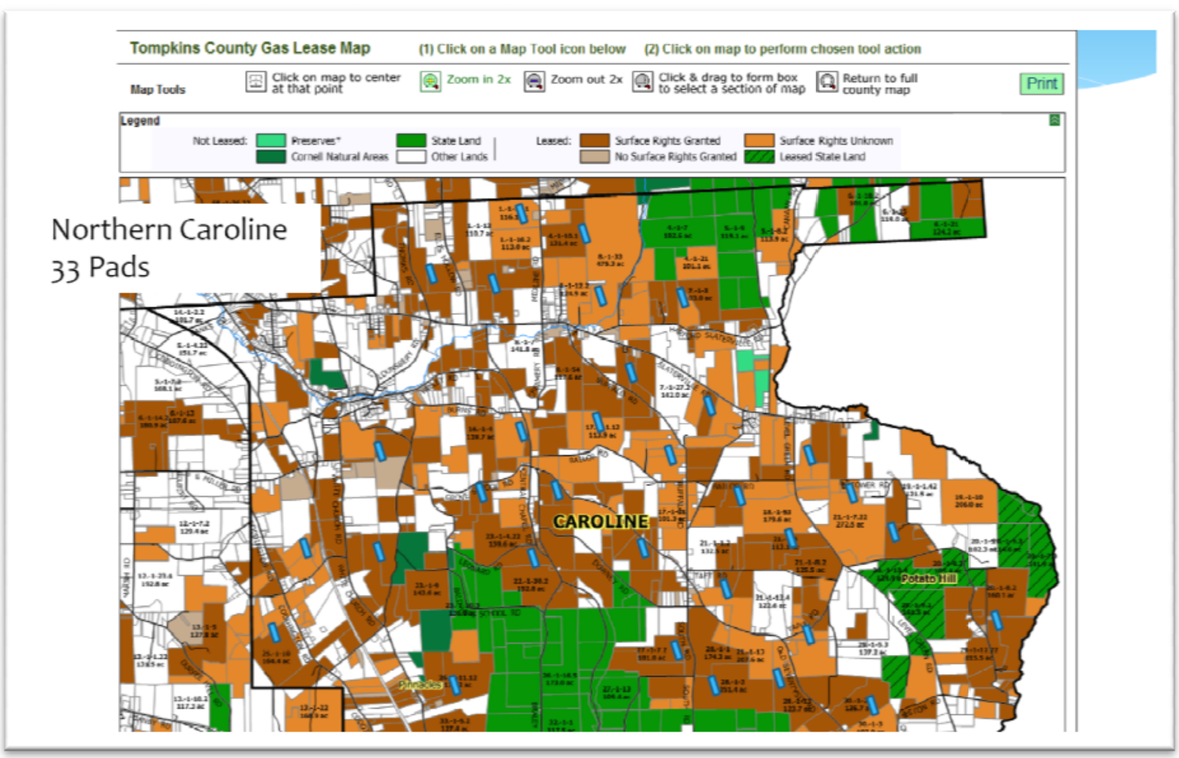
6.1.2 Regional Traffic Congestion and Safety Impacts

In addition to analyzing one well site in detail, it is important for NYSDEC to analyze regional cumulative impacts because these types of impacts will not likely be considered at the site level in the review of individual permits. The regional analysis would consider changes in traffic volumes on major roadways and the resulting potential for increased congestion and crashes from the combined effects of truck traffic to individual wells, as well as traffic related to additional employment and population growth. One methodology for conducting a meaningful regional analysis would be to use an existing travel demand model within the Marcellus and Utica shale regions. Unfortunately, neither New York State nor the Metropolitan Planning Organizations (MPOs) in Region A have a statewide or regional travel demand model. However, there are still several possible options for NYSDEC to conduct a meaningful regional scale transportation modeling analysis.

One option would be to use an analysis of Tompkins County as a surrogate for similar regional scale impacts that could occur in other places. There are several advantages to this approach:

- The Ithaca-Tompkins County Transportation Council (ITCTC) has an existing travel demand model that covers all of Tompkins County.

- The Tompkins County Council of Governments Task Force on Gas Drilling has identified realistic scenario of potential well locations for Tompkins County based on a GIS analysis and information from the 2009 DSGEIS.[18] An example map output from this analysis is provided in the figure below.



[18] http://www.tompkins-co.org/tccog/Gas_Drilling/Focus_Groups/Mapping.html

Example of Well Pad Placement Assessment for the northern portion of the Town of Caroline, Tompkins County. Source: http://www.tompkins-co.org/tccog/Gas_Drilling/Focus_Groups/Mapping%20Minutes/Section%203%20-%20TC%20Mapping%20Analysis.pdf

The travel demand model could be run for multiple scenarios but, at a minimum, future no action and action (peak year of traffic generation) scenarios should be run. Key considerations in setting up the model should include identifying the traffic analysis zones that would experience increased population and employment and appropriately defining the trips attracted to well sites and other important destinations, such as hypothetical water source areas and waste disposal areas. These parameters could easily be established by a team composed of a travel demand modeling expert and a person familiar with hydraulic fracturing well site development stages and trucking needs (making the assumptions available for public review). A cooperative study in partnership with the ITCTC could be particularly beneficial to take advantage of their familiarity with local conditions and the existing model.

Once the model runs are complete, the results should be post-processed and used to develop an informative impact analysis and mapping (e.g., link volume change maps, volume/capacity ratio maps, etc.). This type of regional analysis is routinely conducted by MPOs as part of the long-range transportation planning process. There are numerous examples and guidance sources available to NYSDEC on how to conduct regional transportation analyses for planning that are equally applicable to generic regional traffic impact analysis.[19]

6.1.3 Statewide Vehicle Miles Traveled Impact

Vehicle miles traveled (VMT) is a key indicator used in transportation planning to compare various future scenarios and investment decisions. Increases in heavy truck VMT provide a basis for drawing general conclusions about the effects of HVHF on the transportation system, as well as effects on air pollutant emissions from mobile sources. While information on the number of trips is discussed in the transportation impacts section of the RDSGEIS, VMT impacts are not addressed. The failure of the transportation section to address VMT impacts is especially problematic because statewide VMT estimates were developed for the air quality analyses in the RDSGEIS (see page 6-176). As discussed in further detail below, the RDSGEIS VMT estimates for air quality should be revised to take into account out-of-state waste disposal and incorporated into the transportation impact assessment section, as well as the air quality section.

As discussed in Glenn Miller's accompanying technical memorandum, the waste disposal requirements for produced water and brines cannot be met at any existing disposal facilities in New York. This means that a significant number of long-distance heavy truck trips would be needed to move wastes out of state for disposal. VMT information for the RDSGEIS air quality analyses was generated using average truck trip

[19]See: NCHRP Report 546: Incorporating Safety into Long-Range Transportation Planning.

FHWA. 2003. "Tools for Assessing Safety Impacts of Long-Range Transportation Plans in Urban Areas."

length information provided by the industry.[20] The industry data was from Bradford County, PA. The data collection methodology and the number of well sites upon which the industry average truck trip length estimates were developed were not disclosed in the RDSGEIS or the industry memo providing the estimates to NYSDEC. Industry estimated 100 truck trips for produced water disposal from each horizontal well, with each waste disposal truck traveling an average distance of 24 miles (one-way).[21] While supporting calculations are not provided to ascertain how the distance of 24 miles was computed, it would appear that the industry's data set was weighted heavily towards well sites where produced brine was reused at other nearby wells. This does not take into account the final disposal transportation impacts. A review of Pennsylvania Department of Environmental Protection (PADEP) waste reports[22] for Bradford County show two primary final disposal sites for brines from wells in the county:

- Pennsylvania Brine and Treatment, Inc. in Franklin, PA (approximately 200 miles from Bradford County municipalities such as Troy).
- Waste-Treatment Corporation in Warren, PA (approximately 140 miles from Bradford County municipalities such as Troy).

The 24-mile trip average distance for waste disposal provided by industry does not reflect the long distance waste hauling that occurs in Bradford County and would be expected to occur in New York. To correct this deficiency, NYSDEC should independently reevaluate the average trip length information provided by industry and develop revised truck trip length estimates that take into account final waste disposal transportation impacts. The assumptions used in generating the average truck trip length estimates should be disclosed for public review. This will allow for a more realistic assessment of the potential transportation and air quality impacts that will result from the statewide increase in VMT.

6.2 Mitigation

The majority of the transportation mitigation discussion in the RDSGEIS is focused on damage to roadways and road use agreements. While this remains an important issue, the RDSGEIS does not give sufficient attention to traffic impact mitigation measures. A list of generic mitigation measures for traffic impacts is provided (Section 7.11.3), but it is not clear when specific mitigation measures would be required because no impact criteria have been defined. For example, at what level of predicted intersection level of service would mitigation have to be considered? NYSDEC should make clear what traffic impact criteria would trigger the need for mitigation measures and include a process for local government and public review of the transportation plans for proposed well sites before NYSDEC issues a permit.

[20] March 16, 2011 Letter from ALL Consulting to IOGA New York, obtained through a FOIL request. The footnote referencing this letter (footnote #100) was missing from the RDSGEIS.

[21] See Exhibit 19A in the March 16, 2011 ALL Consulting letter

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[22] Pennsylvania Oil and Gas Well Statewide Waste Report by Reporting Period. Jan - Jun 2011 (Marcellus Only, 6 months)
https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/DataExports/DataExports.aspx

Table 4 summarizes the transportation mitigation commitments in the RDSGEIS and shows that many of these commitments were not carried through to the EAF, EAF Addendum, regulations or supplemental permit conditions. The mitigation measures not included in the EAF, regulations or permit conditions are not enforceable. The proposed supplemental permit conditions do contain specific requirements to mitigate air quality impacts (Appendix 10, Attachment A); therefore it would be reasonable and consistent to also include many of the transportation mitigation measures in Table 4 as supplemental permit conditions. Other mitigation measures are general enough to apply to all well sites and should be incorporated into regulations as described in the “notes” column of Table 4.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate transportation impacts of HVHF, and use this information to refine the transportation mitigation requirements for future permit applications.

Table 4
Transportation Impacts Mitigation Matrix

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Development of Transportation Plans, Baseline Surveys, and Traffic Studies. (7-136)	Yes	Yes (560.3)	Yes- transportation plan must be approved by NYSDEC and is "incorporated by reference" into the permit	The details of the transportation plan related-requirements should be described in greater detail in the EAF Addendum, along with an example transportation plan to provide clear guidance to industry on the level of data collection and analysis NYSDEC and NYSDOT expect.
Municipal Control over Local Road Systems. (7-137)	N/A	N/A	N/A	This is a mitigation measure that cannot be implemented by NYSDEC- it relies on municipalities with very limited planning resources to be proactive in protecting their roads.
The owner or operator should attempt to obtain a road use agreement with the appropriate local municipality; if such an agreement cannot be reached, the reason(s) for not obtaining one must be documented in the Transportation Plan. The owner or operator would also have to demonstrate that, despite the absence of such agreement, the traffic associated with the activity can be conducted safely and that the owner or operator would reduce the impacts from truck traffic on local road systems to the maximum extent feasible. (7-138)	Partial- copy of road use plan must be submitted if there is one.	No	Partial- copy of road use plan must be submitted if there is one.	Applies to all wells, should be in regulations
Route selection to maximize efficient driving and public safety, pursuant to city or town laws or ordinances as may have been enacted under Vehicle and Traffic Law §1640(a)(10). (7-138)	No	No	No	Applies to all wells, should be in regulations
Avoidance of peak traffic hours, school bus hours, community events, and overnight quiet periods, as established by Vehicle and Traffic Law §1640(a)(20). (7-139)	No	No	No	Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Coordination with local emergency management agencies and highway departments. (7-139)	No	No	No	Applies to all wells, should be in regulations
Upgrades and improvements to roads that will be traveled frequently for water transport to and from many different well sites, as may be reimbursable pursuant to ECL §23-0303(3). (7-139)	No	No	No	Refers to provision of ECL that allows municipalities to request from NYSDEC "funds from the oil and gas fund to reimburse the municipality for costs incurred in repairing damages to municipal land or property. Such requests shall include such explanatory material and documentation as the commissioner may require."
Advance public notice of any necessary detours or road/lane closures. (7-139)	No	No	No	Applies to all wells, should be in regulations
Adequate off-road parking and delivery areas at the site to avoid lane/road blockage.(7-139)	No	No	No	Provision of large parking and delivery areas may increase the footprint of the well development sites, increasing ecological and water quality impacts.
Use of rail or temporary pipelines where feasible to move water to and from well sites. (7-139)	No	No	No	
Prior to site disturbance, the operator shall submit to the Department and provide a copy to the NYSDOT of any road use agreement between the operator and local municipality. (7-139)	Yes	No	Yes	Applies to all wells, should be in regulations
The operator shall file a transportation plan, which shall be incorporated by reference into the permit; the plan will be developed by a NYS-licensed Professional Engineer in consultation with the Department and will verify the existing condition and adequacy of roads, culverts, and bridges to be used locally. (7-139)	Yes	Yes	Yes	

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Mitigating Incremental Damage to the State System of Roads. (7-141)	N/A	N/A	N/A	Damage to the state road system is identified in the RDSGEIS as an unmitigated impact. The Final SGEIS and HVHF regulations should include a transportation fee on permit applications to compensate for the costs of repairing HVHF-related damage to the state road system.
Limiting truck weight, axle loading, and weight during seasons when roads are most sensitive to damage from trucking (e.g., during periods of frost heaving and high runoff). (7-141)	No	No	No	
Requiring the operator to pay for the addition of traffic control devices or trained traffic control agents at peak times at identified problem intersections or road segments. (7-141)	No	No	No	
Providing industry-specific training to first responders to prepare for potential accidents. (7-141)	No	No	No	
Road use agreements limiting heavy truck traffic to off-hour periods, to the extent feasible, to minimize congestion. (7-141)	No	No	No	
Providing a safety and operational review of the proposed routes, which may include commitments to providing changes to geometry, signage, and signaling to mitigate safety risks or operational delays. (7-141)	No	No	No	
Avoiding hours and routes used by school buses. (7-141)	No	No	No	

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
1.0 Where appropriate the Department would impose specific construction windows within well construction permits in order to ensure that drilling activity and its cumulative adverse socioeconomic effects are not unduly concentrated in a specific geographic area. Those 2.0 measures, designed to mitigate socioeconomic impacts and impacts on community character, can also be employed to minimize operational and safety impacts where such impacts are identified. (7-142)	No	No	No	The effectiveness of this measure is difficult to assess because the RDSGEIS does not explain what criteria would trigger a limitation on well permits within a specific area. Applying an adaptive management approach is logical, but it requires substantial resources and planning to monitor well development pressures at the local level. NYSDEC has not explained how such a monitoring system would be implemented, and thus this mitigation measure is likely to be ignored or forgotten once NYSDEC starts issuing permits.
Reducing trucking through different technology, such as on-site treatment. (7-142)	No	No	No	
The operator will provide specific information on the types and quantities of hazardous materials expected to be transported through the jurisdictions that they will be operating in and brought on site as part of the permitting process. (7-142)	Yes	Yes (560.3)	Yes	
All fracturing fluids and additives are transported in “DOT-approved” trucks or containers. (7-142)	N/A	N/A	N/A	This measure cannot be enforced by NYSDEC- depending on federal or NYSDOT oversight of hazardous material movement.
First responders and emergency personnel would need to be aware of hazardous materials being transported in their jurisdiction and also be properly trained in case of an emergency involving these materials. Permit conditions may require the operator to provide first responder emergency response training specific to the hazardous materials to be used in the drilling process if a review of existing resources indicates such a need. (7-143)	No	No	No	Applies to all wells, should be in regulations

RDSGEIS Mitigation Commitment	Incorporated in EAF or EAF Addendum	Incorporated in Proposed Regulations	Incorporated in Supplemental Permit Conditions	Notes
Transportation plans may provide that sensitive locations be avoided for trucks carrying hazardous materials. (7-143)	No	No	No	To make this mitigation measure meaningful, it would be helpful for NYSDEC to identify the specific categories of sensitive facilities that permit applicants must identify and avoid in developing trucking routes (bridges over drinking water supply reservoirs for example).

6.3 EAF and EAF Addendum

A transportation plan is a required component of the EAF Addendum. The scope of the transportation plan is discussed in RDSGEIS Section 7.11.1.1 and includes "the number of anticipated truck trips to be generated by the proposed activity; the times of day when trucks are proposed to be operating; the proposed routes for such truck trips; the locations of, and access to and from, appropriate parking/staging areas; and the ability of the roadways located on such routes to accommodate such truck traffic." NYSDEC should provide details on the scope of the specific analyses that should be performed for the transportation plan to ensure a uniform approach is used.

7.0 Community Character

7.1 Impact Assessment

Community character is an amalgam of various elements that give communities their distinct "personality." These elements include a community's land use, architecture, visual resources, historic resources, socioeconomics, traffic, and noise (CEQR Tech. Manual). The community character impact assessment portion of the RDSGEIS lists some of the community character impacts that could be expected (focused on demographic and economic impacts), but does not analyze the significance of these impacts or draw conclusions on how proposed new natural gas development in the Marcellus and Utica shales would affect community character in the short-term and long-term. The impact assessment does not mention the contribution of visual, land use or historic resource impacts to community character. The discussion of traffic and noise impacts is superficial (two sentences each).

The community character impact assessment in the RDSGEIS appears to be based on the *Impacts on Community Character of Horizontal Drilling and High Volume Hydraulic Fracturing in Marcellus Shale and Other Low-Permeability Gas Reservoirs* report prepared by NTC Consultants for NYSERDA. To the extent the analysis in the RDSGEIS derives from or relies upon this report, it is significantly flawed in that for the most part it considers a few of the elements of community character individually (visual, noise, traffic), without drawing conclusions on the cumulative impact of all the changes associated with the expected level of new development. Much of the cumulative impact discussion in the report focuses on attempting to explain why a regional cumulative impact assessment based on a reasonable worst case development scenario is not necessary or helpful. The report also states:

> "The approach for addressing regional cumulative impacts is to focus on the proactive siting of well pads as discussed in previous sections of this report. If the location and construction of each well pad is based on 'Best Practices' (See Appendix A) then the potential impacts will be lessened and/or eliminated. **When applications are reviewed, it is recommended that DEC examine any negative issues that have occurred on adjacent well pads to determine if there is a potential problem in the area that needs further scrutiny**." Page 38. Emphasis added.

The suggested approach is to let the impacts occur and then do something about those impacts if there is a problem. NYSDEC adopted this approach in the form of the vague mitigation commitment to monitor the pace of well development and respond through limits on permits in specific areas to minimize cumulative socioeconomic impacts (see page 7-120). This is contrary to SEQRA, the intent and spirit of which is to consider impacts *before* making a decision to approve the proposed action. NYSDEC must address regional cumulative community character impacts and not defer the issue to the future after the impacts have occurred. An adaptive management framework to addressing HVHF impacts is useful (as discussed further below), but this does not excuse the omission of a complete community character impact assessment in the RDSGEIS.

7.2 Mitigation

The community character mitigation section of the RDSGEIS focuses on the EAF Addendum requirement related to consistency with local plans. There is also a mitigation commitment requiring site-specific review and additional mitigation measures of disturbance of 2.5 acres or more within an agricultural district. However, the agricultural district mitigation commitment is not enforceable because it is not included in the EAF Addendum, regulations or supplemental permit conditions.

The community character mitigation section also references the visual, noise, transportation and socioeconomic mitigation commitments in Chapter 7. However, as noted in the other sections of this review, enforceable mitigation has not been provided for those topics, which means that the unmitigated impacts in those subject areas will contribute to unmitigated community character impacts.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate community impacts of HVHF, and use this information to refine the community impacts mitigation requirements for future permit applications. NYSDEC contemplates such a similar approach in the discussion of mitigation for socioeconomic impacts (page 7-120), but the details of how this monitoring system would work need to be defined and circulated for public review and comment.

7.3 EAF and EAF Addendum

Community character impacts are not addressed as a distinct topic in the EAF or EAF Addendum.

8.0 Cultural Resources

8.1 Impact Assessment

Cultural resources, also referred to as historic properties, link a community with its past. These are finite resources and are provided protections through local, state, and federal authorities. In the 1992 GEIS, cultural resources were addressed as one of the major environmental issues. In GEIS Chapter 6, a background of these environmental resources and a review of the then-existing authorities (in addition to SEQRA) was provided, noting “the revised, shortened and simplified EAF should still remain as an attachment to the drilling permit application form (FGEIS page 31).” The simplified EAF includes cultural resources and offers the New York State Office of Parks, Recreation, and Historic Preservation (OPRHP, the State Historic Preservation Office) as a source for information along with the DEC Division of Construction Management-Cultural Resources Section and the DEC Division of Regulatory Affairs-Regional Office. There was limited discussion of the potential cultural resource issues beyond that identified on pages 6-16, 7-7, and 16-11 through 16-12. Further, although the 1992 GEIS highlighted the need for consultation between NYSDEC and the OPRHP, there was no formal process for consideration of cultural resources outlined.

Despite the length of time since the 1992 GEIS was issued, the 2009 DSGEIS and the RDSGEIS provide no update or reaffirmation of the authority-driven procedures for taking potential impacts to cultural resources into account beyond referring back to the 1992 GEIS. For example, how will tribal consultation be addressed given the 2009 DEC policy, *Contact, Cooperation, and Consultation with Indian Nations*:

> “’Affecting Indian Nation interests’ means a proposed action or activity, whether undertaken directly by the Department or by a third party requiring a Department approval or permit, which may have a direct foreseeable, or ascertainable effect on environmental or cultural resources of significance to one or more Indian Nations, whether such resources are located on or outside of Indian Nation Territory.”

In the RDSGEIS there is limited new discussion of cultural resource issues despite comments provided during the scoping process by the New York Archaeological Council (NYAC) dated December 11, 2008, outlining the potential loss of valuable scientific information should no consideration be given to these finite resources. NYAC reinforces the direct impacts to archaeological deposits that can result from any ground disturbing activity and offers comments on potential indirect impacts, such as vibration from drilling and increased vehicular traffic that could impact fragile archaeological deposits, or the potential for loss or degradation of the information that could be gleaned from specialized analyses of archaeological features that may result from changes to the soil matrix with the introduction of chemical additives as well as the potential for indirect (visual, vibration) impacts to historic architectural resources. Despite the availability of these comments, the additions to the RDSGEIS focus solely on the potential for visual impacts but disregard NYAC’s other recommendations, a notable deficiency in the 1992 document.

In \RDSGEIS Chapter 3, there is no mention of cultural resources relative to SEQRA beyond the reference back to the 1992 findings. In Chapter 6, there is no discussion of cultural resources; while the 1992 document and its findings are incorporated by reference and this chapter is intended to address new issues, this is a missed opportunity to consider potential impact to cultural resources. Consider the potential situation where a cultural resource, such as the remnants of an old water-powered mill complex that once was the economic hub for a small community or what remains of an historic vessel scuttled during a military skirmish, is submerged or partially submerged in an anaerobic environment. With a reduction in stream flow there is the potential to degrade the resource, rendering it subject to deterioration and potential loss. Without consideration of a broadly defined area of potential effect at the outset when the siting application and all its associated contingencies (e.g., well pads, gathering lines, distributions lines, access roads, resource or water needs, etc.) is reviewed, there is the potential to impact cultural resources.

The RDSGEIS does note in Chapter 8, Table 8.1, that OPRHP has a role in “well siting” and in “new in-state industrial treatment plants” but these are shown with an asterisk, with the caveat “role pertains in certain circumstances.” On page 8-6, it is noted that “[i]n addition to continued review of well and access road locations in areas of potential historic and archeological significance, OPRHP will also review locations of related facilities such as surface impoundments and treatment plants.” On page 8-37, the State Historic Preservation Act (SHPA) is brought into play with respect to dam safety permitting criteria and thresholds for resource consideration. And in Appendix 14 (Department of Public Service Environmental Management & Construction Standards and Practices –Pipelines), cultural resources are listed under the portion of the checklist for “Procedures for the Identification and Protection of Sensitive Resources.”

Thus, the big issue that has not been adequately outlined and addressed is how cultural resources will be handled in the overall permitting process; in particular, what is the procedural means and proposed agency coordination for cultural resources identification, and impact evaluation, minimization, avoidance, mitigation?

8.2 Mitigation

The RDSGEIS mitigation section for visual resources suggests that mitigation measures would be considered when designated significant visual resources associated with historic resources are present and within the view shed of proposed wells. However, in order to determine whether there is a view shed impact on a historic resource the resource itself must be identified, and evaluated before a determination of impact can be made. Because the RDSGEIS does not, as noted, indicate how this will be done, it is impossible to evaluate whether the process for impact identification and mitigation pursuant to SEQRA will be adequate.

The same can be said for ***all*** potential cultural resource impacts, such as those to archaeological sites which are rarely visible on the surface – mitigation measures would be considered once any resources have been identified, evaluated for significance, and a determination made that the impact cannot be avoided or minimized. It is expected that this process is to be undertaken during consideration of well siting applications (which should take into account gathering and distribution lines, access roads, all potential ground-disturbing impacts as well as potential indirect impacts [i.e., vibration, chemical, visual, etc.]). Unfortunately, this approach does not allow the public adequate review of possible mitigation efforts.

Finally, NYSDEC should develop an adaptive management framework for monitoring the effectiveness of measures implemented to avoid, minimize, or mitigate cultural resource impacts of HVHF, and use this information to refine the cultural resource mitigation requirements for future permit applications.

8.3 EAF and EAF Addendum

As noted above, the process for addressing potential cultural resource impacts is not fully developed beyond the EAF checkboxes and DEC review of the application.

9.0 Aquatic Ecology

The assessment of aquatic ecology issues focused on the following items:

- Potential for impairment of the “best use” classifications of the State’s surface waters due to cumulative impacts.
- Potential for the alteration or degradation of critical aquatic habitat for aquatic species with limited distributions and sensitivity to water quality, such as trout and salamanders (e.g., the common mudpuppy (*Necturus maculosus*).
- Potential for aquatic habitat fragmentation (i.e., the isolation of existing populations).

LBG’s review of Sections 6.1.1.2, 6.1.1.3 and 6.1.1.4 of the RDSGEIS indicates that the document does not fully characterize the potential environmental impacts leading to the potential degradation of a stream’s best use classification, and the alteration of aquatic habitats and ecosystems due to direct and cumulative impacts. The RDSGEIS inadequately addresses the potential for the regulated development of high-volume hydraulic fracturing to alter critical aquatic habitat for sensitive species, specifically trout and salamanders, and no provisions are made in sections 7.1 and 7.4 to require standard mitigation measures to ensure degradation is avoided.

Pursuant to NY State Environmental Conservation Law regulations, Chapter X - Division of Water, Article 2, Part 701, all fresh surface water classes have a general condition that does not allow the discharge of wastes to impair the best usage of the receiving water, and all surface water use classifications “shall be suitable for fish, shellfish, and wildlife propagation and survival.” The regulations provide for further discharge restrictions to surface waters that occur within the RDSGEIS study area, including:

- Part 701.20: c.2 – waters that contain “critical aquatic habitat for fishes, amphibians, or aquatic invertebrates listed as endangered, threatened, or of special concern in Part 182 of this Title”; d.3 “small trout spawning streams;”
- Part 701.25 a. – waters that are labeled with the symbol (T) are “classified waters in that specific item are trout waters. Any water quality standard, guidance value, or thermal criterion that specifically refers to trout or trout waters applies;” and,
- Part 701.25 b. – waters that are labeled with the symbol (TS) are “classified waters in that specific Item are trout spawning waters. Any water quality standard, guidance value, or thermal criterion that specifically refers to trout, trout spawning, trout waters, or trout spawning waters applies.”

The purpose of the discharge designations is to provide further protection to these waters by defining their best use as the maintenance of aquatic species diversity and populations of sensitive or diminishing species that are sensitive to the degradation of water and habitat quality. The combined land use changes caused by well pad development, roadway network improvements and expansion, and supporting infrastructure should be described within the RDSGEIS at a watershed scale that is practical to the management of aquatic resources.

To assist in defining a potential scale, LBG prepared maps that depict the frequency, spatial distribution and arrangement of discharge restricted sensitive aquatic environments (trout streams) at two watershed scales (See Figures 1 and 2). Figure 1 shows the distribution of streams with NYSDEC discharge designations for trout within the Unadilla river watershed, a large tributary to the Susquehanna River with a 520 square mile watershed. Figure 1 shows the number of and connectivity between patches of existing stream habitat and populations of trout, and presumably other sensitive aquatic species. Figure 2 shows the Lower Butternut Creek watershed at the Hydrologic Unit Code (HUC) 12 level, with a 52.16 square mile watershed. Lower Butternut Creek is a tributary of the Unadilla River. At this scale, Figure 2 can be used as a planning level tool to depict aquatic habitat cores, islands, and corridors for a single or multiple populations of aquatic species. The scale is also practical for relating well pad and ancillary features with potential impacts and mitigation considerations. In the RDSGEIS, NYSDEC should use similar planning tools to evaluate more thoroughly potential impacts to aquatic habitat.

Table 5 below summarizes the watershed features of size, length of trout supporting (T) and trout spawning (TS) designated waters, and length of existing roads for both figures.

Table 5
Watershed Statistics

Watershed	Watershed Size (sq. miles)	Non-Trout Waters (miles)	Trout Supporting/ Trout Spawning Waters (miles)	Existing Roads (miles)
Unadilla River	520	587.63	461.85	1488
Lower Butternut Creek	52.16	88.26	49	134

Construction of well pads, access roads and supporting infrastructure may impact two major watershed processes which could have multiple cumulative effects on surface waters.

The first process is the increase in concentrated runoff from construction sites due to precipitation or snow melt through the re-routing and concentrating of diffuse overland sheet flow into roadside ditch networks, and the reduction in soil infiltration and permeability due to land development (or changes in water supply distribution) (Rosgen 2006, Forman et al. 2003, Leopold and Langbein 1960).

Second, the increase in sediment from the introduction of miles of new access roads with a gravel base, unpaved shoulders, and/or unconsolidated drainage conveyances/ditches, and stream crossings is a process that can lead to changes in sediment supply. Gravel roads, even when properly constructed and maintained, provide a source of sediment, especially during high traffic periods (Rosgen 2006, Forman et al. 2003, Reid and Dunne 1984). Each of these items is discussed below.

9.1.1 Land Use

Sections 5.1.1, 5.1.2 and 5.1.3 of the RDSGEIS describe the extent of land disturbance during the drilling and fracturing stage for a well pad and ancillary features (access roads, utility corridors, compressor stations, etc.). The average total disturbance was estimated at 7.4 acres for a multi-well pad and 4.6 acres for a single well pad.

Section 5.1.4.2 of the RDSGEIS states that the spacing of disturbances from horizontal wells with multiple wells drilled from common pads is “up to 640 acres,” which is approximately one well pad per square mile. An “on average” spacing estimate is not provided; therefore, a typical disturbance footprint spacing has not been quantified. Analyses of cumulative impacts at a watershed scale require a practical spacing or range of spacing to better evaluate the need for regulatory limitations on well pad densities. If truly representative of the affected acreage, a single 7.4 acre multi-well pad represents approximately 1.5 percent of the area within a square mile.

A common component of construction is the clearing, grading and compaction of land within the disturbance footprint. These actions impact the naturally occurring drainage patterns outside of the disturbance footprint by re-routing and concentrating diffuse overland sheet flow produced by precipitation or snow melt (Leopold and Langbien, 1960; Leopold, 1994), re-directing this water through surface conveyances such as a ditch network (Foreman et al. 2003), which can change the timing and path of water supplied to surface waters within the watershed (Rosgen, 2006) or the hydrologic regime (Poff et al., 1997). The RDSGEIS does not specifically address these processes or address potential mitigation measures for inclusion as permit conditions within the regulatory program.

In reference to partial reclamation of the well pad, Section 5.16.1 states that “[s]ubsequent to drilling and fracturing operations, associated equipment is removed. Any pits used for those operations must be reclaimed and the site must be re-graded and seeded to the extent feasible to match it to the adjacent terrain. Department inspectors visit the site to confirm full restoration of areas not needed for production.”
The intention of partial reclamation of a pad during the production phase is to further reduce the footprint of the disturbance. However, this section does not describe details about how long each phase lasts, does not provide a reclamation time table, or performance standards. Therefore, it is difficult to classify the disturbance as a temporary or permanent impact. The section provides insufficient elaboration or methods and does not define the industry standards or success criteria for reclamation activities and the environmental benefits they may provide; therefore, the value of reclamation as mitigation is also unclear.

Land use restrictions using impervious area thresholds are used to maintain brown trout populations in suburban watersheds in Delaware, Maryland and Pennsylvania (Kauffman and Brant, 2000) which is based on limiting impervious surfaces to less than 10% coverage of a watershed. Brook trout populations, the very species associated with T and TS stream designations in NY have become extirpated in watersheds with impervious land uses above 4% coverage, and stress upon brook trout populations was inversely related to impervious watershed coverage (Stranko et al., 2008). Brook trout population presence is shown to have a positive relationship with forested watershed coverage above 68% (Hudy et al. 2008). Collectively, this information demonstrates that cumulative watershed land use changes induced by HVHF that impact forested land and increase impervious cover is likely to cumulatively impact NY State designated trout and trout spawning waters which could well lead to the loss of the waters’ best use designations. NYSDEC should address these issues in the RDSGEIS. In addition, related impacts to tourism are not discussed here but should be as these impacts are an indirect effect of natural habitat degradation and natural habitat is an established State tourism asset.

9.1.2 Access Roads

Section 5.1.1 of the RDSGEIS states “industry estimates an average access road size of 0.27 acre, which would imply an average length of about 400 feet for a 30-foot wide road. Permit applications for horizontal Marcellus wells received by the Department prior to publication of the 2009 DSGEIS indicated road lengths ranging from 130 feet to approximately 3,000 feet.” The Executive Summary, Chapter 2 summary of the RDSGEIS states “the Department has determined, based on industry projections, that it may receive applications to drill approximately 1,700 - 2,500 horizontal and vertical wells for development of the Marcellus Shale by high-volume hydraulic fracturing during a ‘peak development’ year. An average year may see 1,600 or more applications. Development of the Marcellus Shale in New York may occur over a 30-year period. Those peak and average levels of development are the assumptions upon which the analyses contained in this RDSGEIS are based.” Based only on the averages considered in the RDSGEIS, an average of 1,600 wells annually, each requiring 400 feet of new road, according to the RDSGEIS would result in over 121 miles of new, likely gravel, roads annually. This would be over 3,600 miles of new roads over 30 years. The RDSGEIS does not address the potential impact of the additional roads on aquatic resources, especially streams with sensitive species.

Stream drainage density relative to road density across a watershed is indicative of the interconnectivity of the roadway drainage system with the stream ecosystem (Foreman et al. 2003). In a regional study of the distribution of brook trout in their native range, average road densities of 3.2 km/sq. km was shown to be a predictor of watersheds that are not likely to support intact brook trout habitat (Hudy et al. 2008). Road density within the lower Butternut Creek watershed is 2.57 miles/sq. mile and the stream density is 2.63 miles/sq. mile. Within the lower Butternut Creek watershed, the stream network is less likely to be designated as Trout or Trout Spawning in areas where roads cross the stream more frequently. For instance, the stream network is designated as Trout or Trout Spawning stream segments are crossed by roads 38 times, and non-trout where stream segments are crossed by roads 54 times or more (Figure 2). While other land use factors can be at play here, road density within a watershed is positively correlated with stream habitat condition. The RDSGEIS should exam available literature on this topic to aid in the assessment of potential long term impacts to trout populations within affected watersheds due to watershed level changes. It is likely that some watersheds currently supporting trout populations are at or near the tipping point of trout sustainability. The RSDGEIS does not address how future HVHF development may affect native trout populations and other sensitive aquatic species.

Road crossings have been identified as a source of habitat fragmentation within linear aquatic systems by forming barriers to fish passage and altering the continuity of fluvial processes (e.g. sediment transport and disconnecting a stream from its floodplain) (Foreman, 2003). Road crossing structures can also change the transport of Large Woody Debris (LWD) (Foreman et al. 2003). LWD is important as an indicator of trout habitat quality (Flebbe and Dolloff, 1995) and in routing, storing and sorting sediment in fluvial landforms (Fisher et al. 2010, Lassettre and Harris 2001, Gomi et al. 2001 and Montgomery et al. 1995).

The alteration of fluvial processes caused by watershed development includes increased peak flows and mobilization of sediment from watershed and stream channel sources (Leopold 1994). Gravel roads, particularly construction and repair of gravel roads, have been shown to be a source of sediment in watersheds (Rosgen 2006) and contribute to habitat degradation (Logan, 2003). Heavy vehicle traffic on gravel roads, up to four heavy vehicles per day, has been shown to contribute up to 130 times more sediment to streams than paved roads (Reid and Dunne, 1984). The drilling and fracturing process can require tens to hundreds of trips by heavy vehicles each time a new well is constructed, thus increasing the likelihood of new sediment loadings to the local stream.
Currently New York State provides no regulatory guidance for stream crossing design which maintains Aquatic Organism Passage (AOP). Vermont Department of Environmental Conservation, Watershed Management Program has developed stream crossing design guidance and stream crossing assessment tools which support AOP and natural channel morphology (The Vermont Culvert Geomorphic Compatibility Screening Tool, 2008 and The Vermont Culvert Aquatic Organism Passage Screening Tool, 2009). These tools can be used to design habitat sensitive crossings at new roads and find mitigation through retrofit or replacement of existing non-habitat sensitive crossings. The Massachusetts Department of Environmental Protection has developed guidance for maintaining gravel roads, ditch networks and stabilizing cut slopes to prevent erosions and reduce sediment inputs to the watershed (The Massachusetts Unpaved Roads BMP Manual, 2001). The adoption or incorporation of these practices as standard BMP measures within the regulatory program should be addressed within the RDSGEIS as a means to minimize potential impacts.

Section 6.4.3 of the RDSGEIS provides an incomplete characterization of potential environmental impacts to endangered and threatened species. While Chapter X, Part 701.20: c.2 states "critical aquatic habitat for fishes, amphibians, or aquatic invertebrates listed as endangered, threatened, or of special concern in Part 182 of this Title" includes discharge designations for waters with species of special concern, the RDSGEIS does not adequately recognize critical habitats for aquatic species of special concern, nor does it provide a complete list of species of special concern that are dependent on aquatic habitats as part of their natural life cycle. There is insufficient evaluation of species of special concern and potential cumulative impacts to threatened, endangered or special concern species within the RDSGEIS.

9.1.3 Recommendations

Based on the review of the RDSGEIS, LBG has found that the document does not adequately address the potential direct and cumulative impacts of HVHF on aquatic resources, New York State designated trout and trout spawning waters, and the potential for the loss of the waters' best use designations. Recommendations to address the deficiencies of the RDSGEIS are provided below.

1. The RDSGEIS should provide a technically supported evaluation method to assess the anticipated changes to land use and road networks at a watershed level and the potential impact to aquatic habitat and sensitive aquatic species.

2. The RDSGEIS should define the restoration standards and success criteria for well pads, access roads and other short term and long term disturbances,

and timelines so that the temporal impacts of these activities and the environmental benefits of site reclamation are clearly defined.

3. Currently New York State does not provide regulatory guidance for stream crossing design which maintains Aquatic Organism Passage (AOP).The adoption or incorporation of these practices as standard BMP measures within the regulatory program should be addressed within the RDSGEIS as a means to minimize potential impacts.

9.1.4 Aquatic Ecology References

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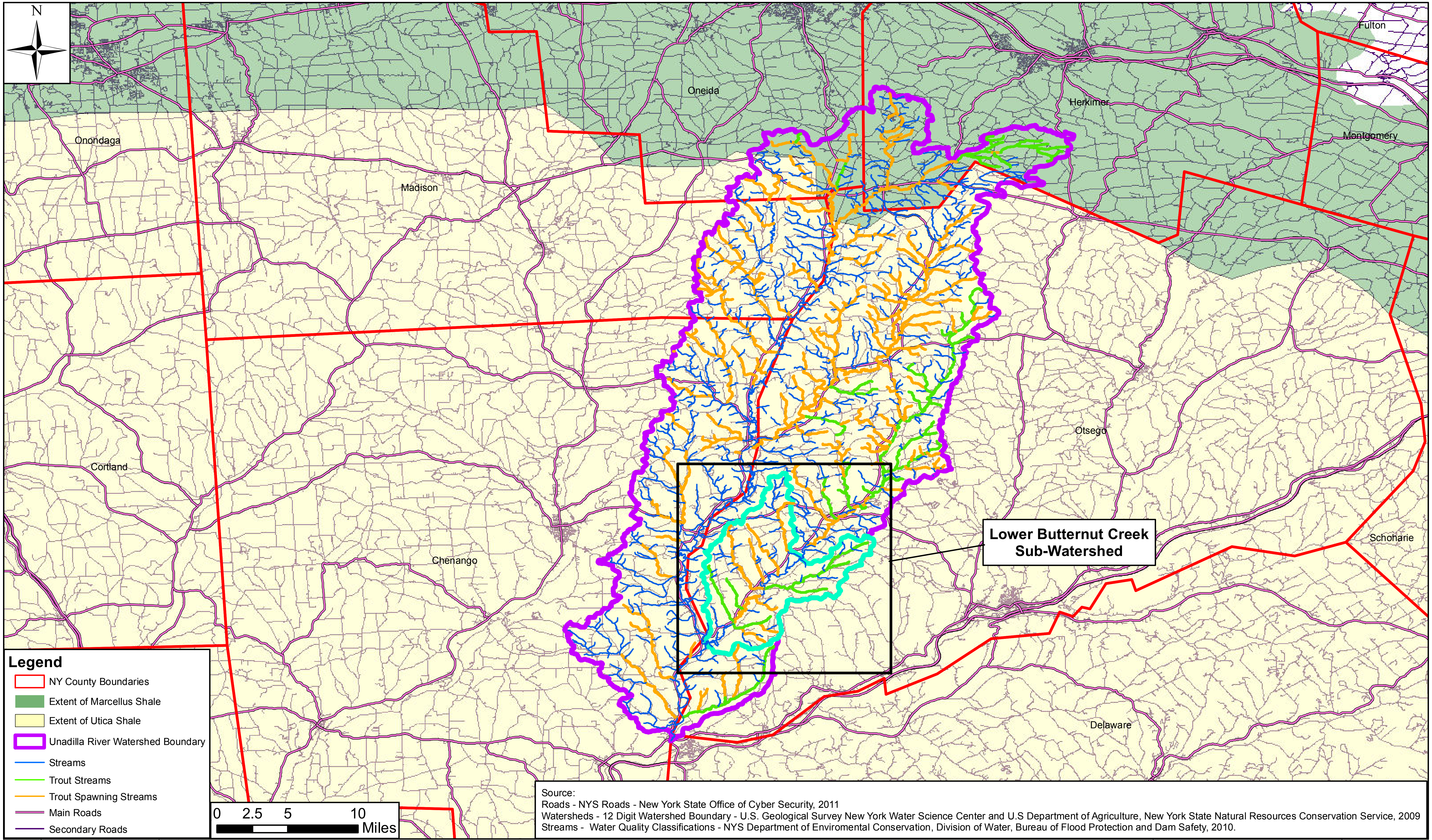


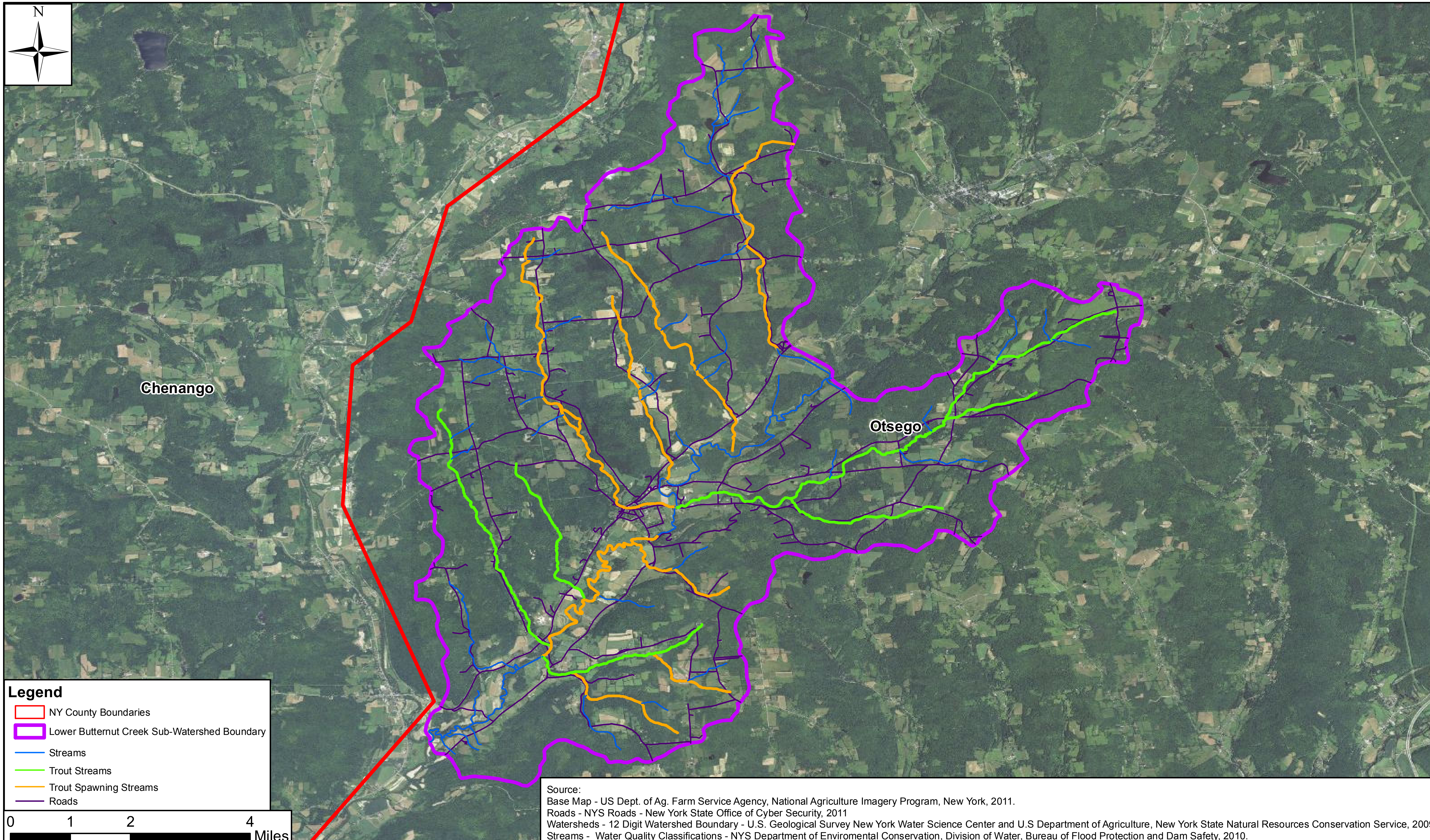
Natural Resources Defense Council

UNADILLA RIVER WATERSHED MAP

NEW YORK

The Louis Berger Group, Inc.
412 Mt. Kemble Ave
Morristown, NJ

FIGURE 1



Natural Resources Defense Council

LOWER BUTTERNUT CREEK SUB-WATERSHED MAP

NEW YORK

The Louis Berger Group, Inc.
412 Mt. Kemble Ave
Morristown, NJ

FIGURE 2

Attachment 8

Kevin Heatley, M.EPC LEED AP

Professional Review & Comment

on

Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program (Revised September 7, 2011)

January 5, 2012

Prepared for:

Delaware Riverkeeper Network

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EXECUTIVE SUMMARY

This review of the New York State Department of Environmental Conservation (NYDEC) revised draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas and Solution Mining Regulatory Program (issued September 7, 2011) was prepared in response to a request by the Delaware Riverkeeper Network to provide expert opinion on issues of terrestrial and restoration ecology. The ecological health and integrity of the forested landscapes located within watersheds has a direct bearing on both the water quality and the biotic composition of the streams and aquatic resources of the Delaware River and other major drainages of the Marcellus and Utica region. Mitigation of land disturbance impacts, such as those associated with unconventional fossil fuel extraction, is critical to ecological sustainability.

The NYDEC recognizes in section 1.2 of the RDSGEIS that it is required by NY state law to "conserve, improve and protect its natural resources and environment . . ." However, the agency openly, and correctly, acknowledges that this mandate cannot be achieved for terrestrial habitats and wildlife resources in the state under the proposed RDSGEIS mitigation recommendations. According to section 7.4.1, "Significant adverse impacts to habitats, wildlife, and biodiversity from site disturbance associated with high-volume hydraulic fracturing in the area underlain by the Marcellus Shale in New York will be unavoidable." The agency presents no mitigation option, such as aggressive region-wide restrictions on the spatial and/or temporal scale of this land disturbance sufficient to negate the undesirable ecological impacts of shale gas development.

The RDSGEIS identified four major areas of concern with respect to ecosystems and wildlife:

1. Fragmentation of habitat
2. Potential transfer of invasive species
3. Potential impacts on endangered and threatened species
4. Use of certain state-owned lands

While the RDSGEIS correctly emphasizes the importance of habitat fragmentation on terrestrial vertebrate species (in particular avian organisms) it fails to document the long term ecological consequences of fragmentation, deforestation, increasing forest edge and reduced surface permeability on desirable forest regeneration, surface water quality, soil chemistry, biodiversity, and sustainable ecosystem services.

Unfortunately, the mitigation measures proposed fail to fully address fragmentation and landscape connectivity issues for the majority of the affected ecosystems. In addition, the proposed invasive species best management practices lack the following key components:

- Quantifiable control metrics
- Latent seed bank management
- Forest edge management

The RDSGEIS also fails to provide any effective regulatory guidance and/or mandates regarding the final ecological restoration of ecosystem structure and function to well pads, pipelines, access road sites, and other related infrastructure upon cessation of natural gas extraction activities.

As written, the revised draft RDSGEIS presented by the NYDEC assures that widespread, dramatic changes in both the current integrity, and the future successional trajectory, of the watersheds and forests in the Marcellus and Utica regions will occur should the anticipated level of landscape industrialization occur. Changes in the successional trajectory (the type of tree species regenerating in the forest understory and that will ultimately comprise the forest canopy) will cause cascading ecological consequences. These changes are likely to result in an undesirable diminution of the ecosystem benefits and services currently provided by these biotic communities. Cascading ecological effects and consequences are probable and will require costly management interventions of significant spatial and temporal scale in order to achieve system restoration.

DISCUSSION

A careful review and analysis of the draft NYDEC RDSGEIS reveals a number of areas of concern with respect to the maintenance of the ecological integrity of terrestrial ecosystems and the corresponding impacts upon aquatic resources. In particular the RDSGEIS does not adequately provide for the protection and sustainable regeneration of critical headwater forests within the Delaware River drainage. Forested ecosystems are the dominant land cover type (57%) within the areas of potential shale gas extraction in the State of New York. This canopy cover is of extreme importance to both the quality and quantity of water that flows within the Delaware River drainage.

Forests filter contaminants, moderate stream temperatures and buffer flow volumes associated with precipitation events. They are the structural foundation upon which the ecological integrity and health of the basin's biological resources are built. The link between percent forest cover and water quality is clearly established in the scientific literature. As an example, reductions in forest cover are directly correlated with negative changes in water chemistry, such as increases in nitrogen, phosphorus, sodium, chlorides, and sulfates, and with reductions in stream macroinvertebrate diversity (Jackson and Sweeny 2010).

A healthy, viable forest canopy creates tangible economic value that accrues directly to local and regional communities. This value comes both from forest-dependent industries and from the ecosystem services (air filtration, climate regulation, water purification, etc.) that the forest provides. For instance, a 2002 survey of 27 water suppliers found that for every 10% increase in forest cover within a municipal watershed, the costs of water treatment and purification decreased by approximately 20% (Ernst, Caryn, Gullick and Nixon 2004). In New York State, forest-dependent industries are estimated to generate nine billion dollars of economic activity on an annual basis (North East State Foresters Association 2001).

Forest fragmentation as a result of anthropogenic landscape modification is well recognized within biogeographic theory and conservation biology as a leading cause of local species extinctions (extirpation). It can also cause dramatic shifts in the floral and faunal composition of woodland communities. Sub-lethal impacts to floral and faunal populations (population isolation, reduced genetic fitness and diversity) have also been associated with disruptions to forest connectivity (Clark, et.al. 2010).

Species dependent upon large, intact areas of interior, or "core" forest and those with limited dispersal abilities are at particular risk from forest fragmentation. A large body of scientific literature associated with neotropical migratory birds clearly links the survival of many of these species to the preservation and restoration of core forest habitat. The Cerulean warbler *(Dendroica cerulean*), a species of special concern in New York State, is a prime example. These populations are already in decline due to massive reductions in the amount of intact core forest. Even if the remaining interior forest habitat is preserved, the extensive fragmentation of the rest of the forested landscape will effectively preclude these areas from reconnection and restoration as interior forest habitat.

As pointed out by Semlitsch and Bodie (2003), the long-term persistence of many amphibian populations depends on the availability of vernal (seasonal) woodland pools and the surrounding, connective forest habitat. The ability of local populations to safely disperse is critical for the survival of these species. For instance, while many species of salamanders return to where they hatched to breed and lay eggs, it has been shown that they will use other vernal pools for breeding if their vernal pool of origin has been disturbed (if it is within their migration distance capacity). Linear disturbance corridors such as roadways and pipeline right-of-ways can create impermeable barriers to movement and effectively isolate populations of these organisms from alternative breeding sites. Isolated populations are at greater risk for extirpation (local extinction). The Jefferson salamander (*Ambystoma jeffersonianum*), another species of special concern in

New York, is an example of an amphibian that will be at risk should significant forest alterations occur.

The development of shale gas infrastructure in the New York and Pennsylvania region will have profound forest fragmentation impacts. Recent modeling work performed by the Pennsylvania Chapter of The Nature Conservancy indicates that approximately 2/3rds of the Marcellus well pads to be built in Pennsylvania will be located in what is currently forested habitat (TNC 2010). Coupled with the associated connective infrastructure of access roads and pipeline right-of-ways (ROWs), disruption of vital ecological processes is assured.

Fragmentation creates an increase in the amount of forest edge (the interface between forest and non-forest). This transitional zone or "ecotone" is fundamentally different in structure and functionality from an interior forest system. Edge habitat is characterized by increased light levels on the forest floor, reduced soil moisture, and a high degree of biological invasion from non-native invasive organisms. Dramatic changes can occur in the soil chemistry and associated micro biota. The top layer of the soil profile, the rich organic duff, begins to dry out and the primary decomposition community begins to shift from fungal to bacterial. Changes in the soil micro biota will result in shifts in the macro biotic community structure. The regeneration of desirable tree species (the successional trajectory) will be affected, potentially impacting the level of valuable ecosystem benefits supplied by the forest. These changes have direct economic implications to both landowners and society. Invasive species, for instance, have been estimated to cost the U.S. economy approximately $120 billion dollars per year (Pimintel et al. 2004).

Invasive organisms within terrestrial forest environments tend to be early successional species that respond favorably to site disturbance. Disruption of native plant cover and the exposure of the forest floor to sunlight provide an opportunity for these organisms to establish satellite populations. These populations eventually radiate out into the adjacent forest, displacing native species and retarding desirable tree regeneration (Bennet et al. 2011). Dispersal (vectoring) mechanisms and/or corridors are required in order for these non-native species to colonize new locations and the access roads, pipelines, and vehicular traffic associated with natural gas extraction are ideally configured to serve this function. Long beyond the point when wells are decommissioned, the landscape legacy of forest edge spreading outward from pipeline corridors, access roads, well pads, and related infrastructure will continue to disrupt ecosystem functioning as non-native organisms repeatedly colonize exposed areas and impede desirable tree regeneration.

Invasive species suppression and the eventual restoration of these disturbed sites to forested systems will require resources of a significant financial and temporal scale. While published information is scarce, it is in the professional experience of restoration practitioners in this region that the reasonable reconstruction of forest canopy and understory diversity can cost between $4,000 and $10,000 per acre. The suppression of invasive plant species is also a major, recurring expense with the initial years' treatment often costing between $1,000 and $2,500 per acre. Invasive treatment in subsequent years typically drops in cost by approximately 50% per year during the first three years of suppression. Treatment and monitoring will need to continue on an annual basis until forest canopy closure is re-established and the resulting changes in light penetration and soil conditions begin to favor native species.

As the effects of forest fragmentation may not immediately manifest themselves following the disturbance, monitoring is often suggested as a methodology to balance and modify the level of fragmenting activity in accordance with the conservation of forest-related ecosystem services. Unfortunately, these effects may not be linear in nature and thus are not always amenable to an adaptive management approach. Biological systems may possess thresholds that provide little indication of impending adverse impacts until sudden system collapse.

It is from within this conceptual framework that a review of the NYDEC Revised Draft RDSGEIS was undertaken and the following concerns identified:

Infrastructure Density-related Ecological Impacts -

- While mandatory unitization of production areas is in effect in New York, this spacing regime is geared toward maximization of gas extraction and not natural resource protection. Preliminary research results already point towards pad density as a significant indicator of potential landscape level impacts to water quality (Academy of Natural Sciences 2011). The RDSGEIS makes no mention of utilizing ecological planning units (such as the sub watershed) or ecological carrying capacity models. This is necessary to assure the industrial development pattern is consistent with the maintenance of ecological integrity.

- Density of infrastructure is also directly correlated to percent impermeable surface within subwatersheds. Increased impermeable surface area will disrupt both surface and subsurface hydrologic regimes within currently forested systems resulting in shifts in species composition and functional benefits. For instance, it is widely accepted among watershed managers that negative changes in water quality and quantity become clearly evident when impermeable surface begins to exceed 10% of a given watershed area. The RDSGEIS-proposed mitigation strategies do not address allowable levels of impermeable surface within ecological planning units such as the subwatershed.

Forest Fragmentation

- While the requirement for ecological assessments and site-specific mitigation measures on well pads placed in grasslands of greater than 30 acres (in grassland focus areas) and for forest patches of greater than 150 acres (in forest focus areas), is helpful this approach is, in essence, ironically fragmented. It completely fails to address the importance of landscape connectivity between patches. As such, it will not protect the landscape-level ecological processes that maintain regional forest integrity. It will also fail to protect connective corridors vital to the movement of plant and animal populations in response to climate change. A preferable methodology would be to set maximum allowable levels of deforestation and fragmentation based upon ecological planning units such as the subwatershed.

- It is strongly recommended that a comprehensive, ecosystem-based plan guide the decision-making and permitting process in place of the piecemeal approach to land use planning and the protection of watershed resources set forth in the RDSGEIS. Setting maximum thresholds and spatial parameters for percent forest cover loss and forest connectivity would assure that density levels and cumulative impacts of natural gas extraction do not exceed the ability of the regional ecosystem to absorb these activities.

- The RDSGEIS correctly emphasizes the importance of minimum patch sizes and landscape connectivity in protecting terrestrial wildlife habitat and/or the human recreation associated with such wildlife. However, no discussion or analysis is present regarding the impact that fragmentation and increasing edge habitat will have upon long term forest successional trajectory and associated biodiversity.

- No analysis has been presented in the RDSGEIS regarding the potential diminution of critical ecosystem services associated with the disruption of forest cover and soils (carbon sequestration and storage, air filtration, watershed flow rates and volume, surface water quality and thermal condition).

- Section 6.4.1.2 estimates that a mere 7% of the forest cover underlain by the Marcellus Shale in NY occurs on State-owned land. However, section 7.4.4 proposes a ban on surface disturbance within state forests and state wildlife management areas only. It is important to understand that this prohibition is not based upon any substantive <u>ecological</u> differences between forests under different ownership.

- Section 7.4.4 gives several reasons for prohibiting surface disturbance on State-owned land including: "Increased light and noise levels would be likely to have significant impacts on local wildlife populations, including impacts on breeding, feeding and migration" and "The local wildlife populations could take years or even decades to recover." These concerns are equally applicable to privately-owned forests, yet full mitigation of these identified impacts to wildlife is not addressed for the remaining 93% of the forest cover in the state. In particular, noise reduction strategies are entirely omitted from section 7.4.1.1 (BMPs for Reducing Direct Impacts at Individual Well Sites).

- Section 7.4.1.1 requires full cutoff (downward) lighting only during bird migration periods. As the ecological impacts of artificial night lighting across a range of species are well documented in the scientific literature, this requirement should be extended year-round.

- Section 7.4.1.1 fails to address BMPs for placement and maintenance of gathering pipelines. As this infrastructure is fundamental to well pad development, and has the potential to disrupt a greater net acreage than the actual pad, BMP recommendations should be developed.

- Section 7.4.1.1 fails to address BMPs for placement and mitigation of compressor station impacts.

- Section 7.4.1.2 indicates that for forest patches of 150 acres or more (within Forest Focus Areas) where the DEC issues a disturbance permit after reviewing the required Ecological Assessment, "enhanced monitoring of forest interior birds during the construction phase of the project and for a minimum period of two years following the end of high-volume hydraulic fracturing activities (i.e., following date of well completion) would be required." While this is an important recommendation, such enhanced monitoring should be extended to less mobile species sensitive to the radical changes in forest floor light and moisture levels that forest fragmentation will cause. Forest-dwelling amphibian species are at a particular risk of extirpation (local extinction) following the loss of interior forest conditions given their limited ability to traverse across linear landscape barriers such as roadways and pipeline ROWs.

- As connectivity between forest patches is critical to allowing for species migration, dispersal, and the continued genetic fitness of terrestrial species, mitigation strategies protective of this landscape level feature should be required. The RDSGEIS does not presently address protection of landscape connectivity and mitigation of disruptions to connective corridors.

- Definition of a disturbed area – clarification should be made as to the minimum size that defines a disturbed area.

- Section 7.4.1.3, *Monitoring Changes in Habitat* recommends, on parcels meeting the threshold criteria in grassland and forest focus areas, that monitoring of disturbance effects should occur during the drilling process and for a minimum of two years following well completion. While monitoring is indeed a valuable tool, effective implementation of operational changes (adaptive management) following and in response to ecosystem disruption is not always possible. Ecosystem response to disturbance may not follow a linear pattern as previously unknown tolerance thresholds may be crossed. Sudden system collapse and the loss of valuable structural and functional features of an ecosystem may occur even in the absence of discernible advance indicators of stress. A more appropriate response would be to apply the precautionary principle and study the likely impacts prior to widespread, and potentially irreversible, landscape modification.

Invasive Species Introduction & Management

- It is recommended that section 6.4 be expanded to include an analysis of the threat potential to forest health from the inadvertent introduction and facilitation of the spread of invasive terrestrial invertebrates and pathogens. The current analysis only considers invasive plants and aquatic organisms.

- The construction of infrastructure necessary to develop the Marcellus and Utica shales will entail the movement of large fleets of vehicles and equipment from various sections of North America. It will also entail the movement of large numbers of transient laborers and technical personnel from across the United States. This activity carries an inherent risk of acting as a vectoring mechanism for a number of threats to forest health. The RDSGEIS should review this potential mechanism of invasive threat and propose mitigation strategies.

- Section 6.4 should also be expanded to include an analysis of the impact that massive increases in forest edge habitat will have upon the incursion and establishment of invasive plant species. Edge habitat is inherently attractive to the type of plant species that display invasive characteristics. Invasive plants tend to be early successional species adapted to disturbed sites. The ecotone between forest and grassland is an area generated by recent disturbance and thus presents ideal conditions for these opportunistic, rapidly-reproducing species. Periodic re-infestation of edge habitat by invasive plant species is also highly probable given the high light levels and frequent deposition of wind-borne and bird-deposited seeds in such areas. The creation of edge habitat on the scale anticipated by natural gas infrastructure is likely to result in chronic, regional infestations of undesirable species that will require regular, and expensive, control interventions. The creation of forest edge is, in and of itself, an important precursor to biological invasion.

- Section 7.4.2.1 fails to include compressor stations and pipeline ROWs in the requirements for invasive species best management practices.

- Section 7.4.2.1 indicates that an invasive species survey "should be conducted by an environmental consultant familiar with the invasive species in New York." It is recommended that the word "should" be replaced by "must".

- It is recommended that the invasive species survey required under section 7.4.2.1 stipulate that percent aerial cover be classified <u>for each</u> identified invasive plant species on the site. Identification of baseline infestation levels is critical to determining target levels of cover reduction and control.

- Section 7.4.2.1 fails to provide any measurable metric, such as percent cover reduction from pre-disturbance levels, for quantifying levels of invasive control. The recommendation strategy that, "Any new invasive species occurrences found at the project location should be removed and disposed of appropriately" should be qualified to include the latent seed bank in the soil.

- Section 7.4.2.1 fails to define the temporal timeframe of responsibility for invasive suppression. The seeds of many invasive plant species can lie dormant in the soil for years. This latent seed bank creates a reservoir for future outbreaks following soil disturbance. It is critical that a long term monitoring and treatment program be implemented for all sites and associated infrastructure. Monitoring and suppression treatments should continue until final site reforestation and effective closure of the tree canopy.

- Section 7.4.2.1 fails to provide a spatial framework for the area of invasive species control responsibility. Invasive species are highly mobile and akin to a wildfire in their dispersal from initial point of infestation. At a minimum, site developers should be required to manage invasive infestations within all forest edge environments surrounding new pads, pipeline ROWs, and newly constructed access roads. Failure to do so will result in migration of these species off-site and the transfer of the financial burden of control onto adjacent property owners.

- As prevention is more cost effective than control, requirements should be adopted mandating independent site inspections by a qualified ecologist on no less than a semiannual basis until final reforestation and canopy closure occurs. Failing to provide for frequent site inspections assures compliance will be minimal.

Site Restoration

- The RDSGEIS fails to provide any meaningful guidance regarding the ultimate restoration of well pads, pipeline ROWs and access roads to full ecosystem functionality upon decommissioning. Effective restoration requires a comprehensive, site-level assessment of the existing plant community prior to disturbance and the use of local reference ecosystems as templates for restoration. Ecological restoration is based upon the concept of rebuilding degraded areas such that they are structurally and functionally similar to pre-disturbance conditions. Reclamation is NOT restoration. Grassy fields neither function in a biologically similar manner as a forest nor supply the ecosystem benefits of a forest system. The replacement of a decades-old, complex assemblage of woodland species with a simple mix of grasses is not "restoration". It may retard erosion but it does not replace the original functionality and structure of the displaced ecosystem.

- Restoration objectives and planning should be integrated into best management practices and developed based upon a landscape-level analysis. Re-establishing forest connectivity should be a primary goal.

- As the service life of gas extraction infrastructure such as transmission pipelines may extend for decades, mitigation banks and sites where restoration of previously degraded systems might off-set the disturbance for the interim period should be utilized. This will help assure that no net loss of ecosystem benefits occurs within the region.

- Requirements for an independent, qualified restoration ecologist to oversee and inspect site restoration should be developed in order to assure effective compliance.

Summary

As currently proposed, the NYDEC RDSGEIS does not provide an adequate assessment of likely impacts associated with the rapid conversion of forested and rural ecosystems to industrial sites. It also fails to recommend potential mitigation strategies and options that would offset and reduce the "significant" impacts anticipated for native terrestrial ecosystems. Protection of these terrestrial ecosystems is critical to the continued health of the regions' aquatic resources. Inadequate attention has been given to the following vital considerations: density related impacts of infrastructure, forest fragmentation, invasive species, and site restoration. Should the RDSGEIS be adopted in its current form, widespread disruption to forest ecosystems within the upper Delaware River Basin and other watersheds underlain by the Marcellus and Utica formations will occur. Restoration of these systems following the eventual cessation of natural gas extraction will be a monumental cost incurred by both the taxpaying public and adjacent private property owners. It is strongly recommended that the NYDEC consider a more comprehensive approach to protecting the integrity of the forested landscapes in New York. Setting maximum thresholds and spatial parameters for percent forest cover loss, forest connectivity, and core forest integrity within ecological planning units, such as the subwatershed, would assure that density levels and cumulative impacts of natural gas extraction do not exceed the ability of the regional ecosystem to absorb these activities.

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Attachment 9

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January 8, 2012

Re: Comments on the RDSGEIS on NY Marcellus Shale Natural Gas Hydraulic Fracturing

These comments are submitted regarding the Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) governing high-volume, hydraulic fracturing as a method of natural gas drilling in the Marcellus Shale and similar formations in New York State.

I am Senior Scientist in the Health and Environment Program at the Natural Resources Defense Council in New York City, and Assistant Clinical Professor in the Department of Environmental Health Sciences at the Mailman School of Public Health of Columbia University. I received my doctorate in Public Health from Columbia University, and much of my research considers the effects of climate change on human health (my CV is attached). These comments relate to climate change and public health concerns raised by the information described in the RDSGEIS.

Although the RDSGEIS describes greenhouse gas emissions that would be generated by Natural Gas Hydraulic Fracturing operations in the Marcellus and other shale formations in NY State (sec. 6.6), and the means to reduce those health-harming emissions (sec. 7.6), the RDSGEIS lacks critical information about the exacerbating effect climatic changes will have on the uncertainties of drilling operations. Further, climate change is likely to increase the risk to public health from HVHF operations if these operations are conducted without regard to the effects of climate change on the environmental context of drilling operations.
Climate change is likely to increase several key uncertainties in shale gas natural gas hydraulic fracturing operations which are not addressed in the RDSGEIS, yet should be. Several of these climate change and public health-relevant omissions are described below:

1. **More frequent extreme rainfall events.** The public health risks of drill pad operations and waste fluid disposal are likely to be affected by more frequent extreme rainfall events in New York State, as climate change continues. These events and the flooding they can cause need to be factored into the RDSGEIS. Measured changes in the heaviest precipitation events in the Northeastern US increased 67% over the period 1958-2007; and the trend toward heavier precipitation is projected to increase into the 2090s.[1] In New York State in the last 60 years from 1948 to 2006, there has been a statistically significant 56% increase in the most extreme rainfall events, according to the a 2007 study by Environment America.[2] As climate change continues, these extreme rainfall events are projected to continue to occur more frequently.[3] The New York Panel on Climate Change (or NPCC), an expert group of university researchers and climate modelers, investigated climate change's effects on New York City and the surrounding region, and projected that annual precipitation in the New York region will "more likely than not" increase, with mean annual precipitation increasing up to 5% by the 2020s, 10% by the 2050s, and

5-10% by the 2080s.[4] The New York State Climate Action Council's Nov. 2010 *Climate Action Plan Interim Report* noted in its Executive Summary (ES) that, "Summertime rain is expected to fall more often as heavy downpours, leading to more flooding; at the same time, the periods between these rainstorms are likely to be drier, leading to droughts. … Public and private entities will need to assess whether new investments in infrastructure, particularly long-lived infrastructure like power plants and transportation, will be consistent with a low-carbon future, both in terms of GHG emissions and in terms of vulnerability to a changing climate. We should avoid investments that are not highly adapted to a modified climate, such as infrastructure sited in low-lying floodplains."[5] ***DEC should act consistently with the recommendations of the New York Climate Action Plan Interim Report by prohibiting HVHF operations and infrastructure in low-lying areas***.

2. **Changes in floodplain location.** The locations of 50-, 100- and 500-year floodplains are likely to change in New York State, owing to the effects of climate change. Extreme rainfall events are becoming more frequent in the US.[6] This trend was also noted in the recently-released NY State ClimAID report: "Intense precipitation events (heavy downpours) have increased in recent decades, and are likely to increase in future."[7] These extreme precipitation events are occurring in tandem with a long-term increase in annual average precipitation of 0.37 inches per decade since 1900.[8] The advent of extreme precipitation events taken together with a general increase in average precipitation is likely to alter the location and size of floodplains. Altered floodplain locations could dramatically compromise the siting and safety of drilling operations, as well as waste disposal and transport. With the trend to heavy downpours over the past 50 years projected to continue, an increase in localized flash flooding in hilly regions across the state is expected. "Flooding has the potential to increase pollutants in the water supply and inundate wastewater treatment plants and other vulnerable development within floodplains."[9] The most recent state of the science on the effects of climate change on the extent of local floodplains should be applied in the RDSGEIS's consideration of the potential impacts of proposed new drilling in NY State.

   Because increasingly frequent and extreme rainfall events could threaten drilling infrastructure, operations and disposal, such investments should be avoided without a full, detailed mapping of areas at greatest risk from storm and flood damage. This is in line with the Nov. 2010 recommendations of the NY State Climate Action Council in their Climate Action Interim Report.[10] Floodplain maps must be fully updated to include the latest information on how climate change will affect local flood plain locations, taken from downscaled climate model projections.[11]

   Although DEC proposes prohibiting surface disturbances in 100-year floodplains[12], this approach is problematic for several reasons. First, DEC should also prohibit subsurface activity in these areas. Second, the prohibition should apply to additional matters involved in HVHF, such as the siting of pipelines and other potentially sensitive infrastructure, the construction of impoundment ponds, the location of temporary waste storage tanks, etc. Third, not only does DEC acknowledge that FEMA is currently updating Flood Insurance Rate Maps (FIRMs) in several high-flood areas in the state,[13] but the Department also admits that the increased frequency and magnitude of flooding has raised a concerns regarding the reliability of the existing FIRMs in the Susquehanna and Delaware River basins.[14] Given this acknowledgment, DEC should extend this prohibition to 500-year floodplains. In general*, **no permits should be issued anywhere in the state before updated floodplain maps are in place for the entire region and these maps are reflected in DEC's environmental review and regulations***. These maps should be reflective of anticipated changes that may result from climate change, namely the increase in frequency and severity of storm events. To permit any activities before properly mapping prohibited areas is inconsistent with SEQRA.

3. **Potential changes in groundwater flow patterns.** Hydrological assumptions about groundwater flow patterns through the Marcellus and other shale formations could be altered by water demands from drilling activities, if coupled with increasingly frequent seasonal drought and/or flood periods in NY State, as climatic instability increases. More frequent alternation between periods of extreme wet and dry periods could, over time, result in changes in groundwater flow patterns[15] and unanticipated movement of production fluids and other groundwater in subsurface fractures and fissures. While challenging to predict, such migration could threaten drinking water supplies. Subsurface hydrological modeling studies have been undertaken to account for some of these climate change effects,[16] yet such studies were ignored by the RDSGEIS. ***No permits to drill near groundwater resources should be issued until climate change-based subsurface hydrological modeling studies have been incorporated into the DEC's review and regulations***.

4. **Changing seasonal precipitation patterns.** Increasing temperatures have already caused spring snowmelt to occur earlier in the year, and climate change will continue to bring changing patterns of seasonal precipitation across the state, with more annual precipitation falling as rain rather than snowfall.[17] This could affect the frequency, intensity and timing of overland flooding events at drill pad sites. In 2011, Hurricane Irene caused extensive flooding across the Catskills and upstate NY, in part because the soils were already so saturated from record-breaking heavy precipitation during the summer. As the USGCRP 2009 report attests, "…water-saturated soils can generate floods with only moderate additional precipitation."[18] In addition to prohibiting water withdrawals during low stream flow, ***the RDSGEIS should explicitly address shifting precipitation patterns resulting from climate change, increased flooding risks, and the public health issues they may create***.

5. **Increasing temperatures could exacerbate chemical volatilization and fugitive emissions from drill sites.** Ambient temperatures are projected to increase across NY State, due to the warming climate.[19] Volatilization of fracking chemicals and fugitive emissions may increase due to higher evaporation rates from higher temperatures. Exposures to workers and the community could increase, exacerbating associated health risks. ***Adverse human health impacts resulting from increased volatilization of fracking chemicals and fugitive emissions should be explicitly addressed in the RDSGEIS.***

6. **Conflicting demands on water use during drought periods are likely to be exacerbated by climate change.** Hydrofracking operations will require enormous quantities of water in drilling, in operations, and as wastewaters are disposed of. Marcellus development is projected over a thirty-year life cycle.[20] The average year would see 1,600 or more wells.[21] The amount of water consumed in each well is projected between 2.4 and 7.8 million gallons,[22] and the average well consumes 4.2 million gallons of water.[23] Based on these numbers, approximately 201,600,000,000 gallons of freshwater will be permanently removed from New York State surface and groundwater sources for the purpose of HVHF operations. The effect of these freshwater diversions in light of predicted climate change impacts to water supplies was not analyzed in the RDSGEIS. Because climate change is likely to disrupt the timing of precipitation's seasonality, the enormous water demands from hydrofracking operations could periodically conflict, during periods of local drought, with those of populations who rely on local surface and groundwater sources for drinking, domestic, municipal, business and agricultural uses. ***The potential for conflicts between HVHF operators and the public over dwindling water supplies resulting from climate change, including the adverse environmental and human health impacts associated with unprecedented freshwater diversions, should be examined in the RDSGEIS, and operators should be prohibited from consuming water from underground, surface, and municipal sources if doing so would exacerbate local drought conditions.***

7. **Nitrous oxide is an extremely potent GHG that the RDSGEIS fails to properly analyze.** Even in its current discussion of greenhouse gases (GHG) generated during drilling operations, the RDSGEIS lacks sufficient information in Sec. 6.6.2 about nitrous oxide (N_2O) as a greenhouse gas (GHG) of concern. The RDSGEIS states that because N_2O is produced in small quantities it need not be explicitly discussed in terms of its treatment or disposal.[24] However, N_2O has a global warming potential 289 times greater than carbon dioxide (CO_2), and an atmospheric lifetime 114 times longer than CO_2.[25] It is injudicious to entirely negate N_2O's effect on climate change in the RDGEIS without fuller discussion of the volumes that would be generated, from what sources, and potential treatment methods. ***The RDSGEIS should identify the impacts associated with N_2O emissions and proposed mitigation measures to curb these emissions.***

8. **Public health impacts.**. Climate change impacts can jeopardize the safety of drilling operations and exacerbate the consequences of HVHF operations on New York State, leading to adverse environmental human health impacts. ***DEC should conduct a comprehensive Health Impact Assessment (HIA) as part of the state's environmental review*** in order to evaluate potential risks to human health from gas development in New York, including the dynamic between HVHF operations (impacts on water quantity and quality, waste runoff, air pollution, etc.) and climate change (water shortages, floods, temperature rise, etc.). ***To assist in the review of comments received, at least one Public Health professional should sit on the team who evaluates the comments received by DEC on the RDGEIS***. Their expertise would be helpful in assessing other potential areas of significant health concern, ranging from air quality, water quality, worker exposure, waste management, etc...

Based on the foregoing, the RDSGEIS is incomplete in its current form. The RDSGEIS is deficient because it does not ever come to grips with the challenges to safe HVHF operations posed by climate change: it does not consider changes in the frequency of extreme rainfall events, changes in floodplain location, changes in groundwater flow patterns, changes in seasonal precipitation patterns, changes in average temperature, potential water use conflicts, the effects of nitrous oxide on climate change, or the public health impacts of climate change in association with HVHF operations. The RDSGEIS fails to include current information relevant to climate change's potential effects on New York State, which will pose potentially significant adverse environmental and public health threats in conjunction with HVHF operations that should be identified and mitigated to the maximum extent possible.

Thank you for consideration of these comments.

Respectfully,

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[1] Global Climate Change Impacts in the United States, Thomas R. Karl, Jerry M. Melillo, and Thomas C. Peterson (eds.). US Global Change Research Program (USGCRP), Cambridge University Press, 2009, p.32.

[2] Madsen T, Figdor E. 2007. When It Rains, It Pours: Global Warming and the Rising Frequency of Extreme Precipitation in the United States. Environment America's Research & Policy Center (December 2007).

[3] IPCC Summary for Policymakers of the Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation (SREX), Nov. 18, 2011. Available at: www.srex.org and www.ipcc.ch.

[4] New York City Panel on Climate Change (NPCC). 2009. Climate Risk Information. Available at: http://www.nyc.gov/html/om/pdf/2009/NPCC_CRI.pdf.

[5] New York State Climate Action Council's Nov. 2010 *Climate Action Plan Interim Report*, Executive Summary, pp.4-5.

[6] USGCRP (2009).

[7] Rosenzweig C, Solecki W, DeGaetano A, O'Grady M, Hassol S, Grabhorn P (Eds.). 2011. *Responding to Climate Change in New York State: The ClimAID Integrated Assessment for Effective Climate Change Adaptation. Technical Report*. (Ch.1, p.16). New York State Energy Research and Development Authority (NYSERDA), Albany, New York. Available at: www.nyserda.ny.gov.

[8] ClimAID Report (2011), p.81 sec. 4.2.2.

[9] Nov. 2010 *Climate Action Plan Interim* Nov. 2010 Report, Overview, p.10.

[10] NY State Climate Action Council, 2010. Climate Action Interim Report, Overview, pp.10, 43, and 48.

[11] Cooney CM 2012. Downscaling Climate Models: Sharpening the Focus on Local-Level Changes. *Environ Health Perspect* 120:a22-a28. http://dx.doi.org/10.1289/ehp.120-a22.

[12] 2011 RDSGEIS, Additional Precautionary Measures, Section 1.8, p. 1-18.

[13] 2011 RDSGEIS, Flood Zone Mapping, Section 2.4.9.2, p. 2-33.

[14] *Id*.

[15] USGRCP (2009), Water sector report, pp. 46-47.

[16] Goderniaux P, Brouyere S, Fowler HJ, et al. 2009. Large scale surface-subsurface hydrological model to assess climate change impacts on groundwater reserves. *Journal of Hydrology* 373:122-138.

[17] ClimAID (2011), Sec. 4.2.1, p.81.

[18] USGCRP (2009), Water Sector report, p.45.

[19] ClimAID (2011), Ch.1, pp.30-36.

[20] 2011 RDSGEIS, Cumulative Water Withdrawal Impacts, 6.1.1.7, p. 6-6.

[21] 2011 RDSGEIS, Description of Proposed Action, Chapter 2, p. 2-1.

[22] 2011 RDSGEIS, Hydraulic Fracturing Procedure, 5.9, p. 5-93.

[23] 2011 RDSGEIS, Cumulative Water Withdrawal Impacts, 6.1.1.7, p. 6-10.

[24] 2011 RDSGEIS, Emissions from Oil and Gas Operations, 6.6.2, p. 6-188.

[25] 2007 Intergovernmental Panel on Climate Change (IPCC), Fourth Assessment Report (AR4), Working Group 1 Technical Summary, Chapter 2, p.212, “Changes in Atmospheric Constituents and Radiative Forcings.”

Attachment 10

Gina Solomon, M.D., M.P.H

MEMORANDUM

TO: Kate Sinding
FROM: Gina Solomon, M.D., M.P.H., Senior Scientist, NRDC; Clinical Professor of Health Sciences, UCSF
DATE: January 9, 2011
RE: NRDC Comments on RDSGEIS, NY Marcellus Shale Natural Gas Hydraulic Fracturing relative to Public Health concerns and Health Impact Assessments

Numerous health concerns have been associated with natural gas development using hydraulic fracturing, including air pollution, potential contamination of groundwater or surface water that may be used for drinking or recreation, toxicity of chemicals used in fracturing fluids, safety concerns such as fire or explosion, increased vehicle traffic, altered social conditions, and the health effects of noise, vibration, and light at night. The RDSGEIS addresses some aspects of a subset of these health issues, but fails by (1) omitting several important health issues entirely, (2) addressing only some aspects of other issues such as air, water quality and traffic without fully considering the health impacts in those areas (Note: this issue is addressed more fully in comments on those sections of the RDSGEIS submitted as part of this package), and (3) failing to consider health issues as a group in a formal Health Impact Assessment (HIA), including the interactive effects on the health of local residents and communities.

The failure to conduct a full HIA as part of the RDSGEIS is an important omission because the health effects of numerous chemicals used and emitted in the course of natural gas development have been well-described.[1] In addition, there are already numerous reports of health complaints among people who live near natural gas drilling and fracturing operations in other states. These health complaints have received coverage in the media,[2] and some cases have been investigated by researchers or government agencies.[3] Reported health issues in residents near natural gas drilling operations include: eye irritation, dizziness, nasal and throat irritation, sinus disorders, bronchitis and other respiratory symptoms, depression, nausea, fatigue, headaches, anxiety, difficulty concentrating, and a range of other symptoms.[4] Just last week, the nation's top environmental health expert

[1] Colborn, T.; Kwiatkowski, C.; Schultz, K., and Bachran, M. Natural gas operations from a public health perspective. Human & Ecological Risk Assessment. 2011; 17(5):1039-1056. http://www.endocrinedisruption.com/chemicals.journalarticle.php. Accessed January 9, 2011; Witter R, Stinson K, Sackett H, et al. Potential Exposure-Related Human Health Effects of Oil and Gas Development: A White Paper. University of Colorado Denver, Colorado School of Public Health, Denver, Colorado, September 15, 2008. Witter R, Stinson K, Sackett H, et al. Potential Exposure-Related Human Health Effects of Oil and Gas Development: A Literature Review (2003-2008) University of Colorado Denver, Colorado School of Public Health, Denver, Colorado, August 1, 2008. http://docs.nrdc.org/health/hea_08091702.asp. Accessed January 9, 2011.
[2] See eg. ProPublica. Science Lags as Health Problems Emerge Near Gas Fields. http://www.propublica.org/article/science-lags-as-health-problems-emerge-near-gas-fields/single. Accessed January 3, 2012.
[3] See eg. ATSDR Health Consultation. Garfield County. http://www.atsdr.cdc.gov/hac/pha/Garfield_County_HC_3-13-08/Garfield_County_HC_3-13-08.pdf. Accessed January 3, 2012; Subra W. Health Survey Results of Current and Former DISH/Clark, Texas Residents. Earthworks, Dec 17, 2009. http://www.earthworksaction.org/library/detail/health_survey_results_of_current_and_former_dish_clark_texas_residents/. Accessed January 3, 2012.
[4] Ibid.

affirmed his view that more research is necessary regarding the impacts of natural gas drilling on human health.[5] Although much research needs to be done to investigate specific associations between the reported symptoms and nearby gas extraction operations, there is sufficient information on health issues associated with the chemicals and other environmental stressors at these sites to demand performance of a full HIA.

> *Health impact assessment is a systematic process that uses an array of data sources and analytic methods and considers input from stakeholders to determine the potential effects of a proposed policy, plan, program, or project on the health of a population and the distribution of those effects within the population. Health impact assessment provides recommendations on monitoring and managing those effects.*
>
> National Research Council, 2011

Rationale for a Health Impact Assessment in New York State

In September 2011, the National Research Council of the National Academies of Science (NAS) issued a report entitled: *Improving Health in the United States: The Role of Health Impact Assessment*. The report recommended the greater use of HIA in decision making in the United States, saying that: "systematic assessment of the health consequences of policies, programs, plans, and projects is critically important for protecting and promoting public health; as indicated, lack of assessment can have many unexpected adverse health (and economic) consequences."[6]

According to the Centers for Disease Control and Prevention (CDC), the HIA framework is used to bring potential public health impacts and considerations to the decision-making process for plans, projects, and policies that fall outside of traditional public health arenas, such as transportation and land use.[7] The National Environmental Policy Act (NEPA) requires federal agencies to consider the environmental impact of their proposed actions on social, cultural, economic, and natural resources prior to implementation. In New York, the State Environmental Quality Review Act (SEQRA) regulations [see 617.2(l)] define Environment as: "…the physical conditions that will be affected by a proposed action, including land, air, water, minerals, flora, fauna, noise, resources of agricultural, archeological, historic or aesthetic significance, existing patterns of population concentration, distribution or growth, existing community or neighborhood character, and *human health*" (emphasis added).[8]

In the United States, HIA is a rapidly emerging practice. HIA is also regularly performed in Europe and Canada. Some countries have mandated HIA as part of a regulatory process. In the U.S., some version of an HIA is arguably required by NEPA and by many state "mini-NEPAs,"[9] including most explicitly, the New York SEQRA,

[5] CDC scientist: tests needed on gas drilling impact. Associated Press. January 4, 2012. http://online.wsj.com/article/AP8338b702930849f49d22a5d96b7d1b2d.html. Accessed January 5, 2012.
[6] National Research Council. Improving Health in the United States: The Role of Health Impact Assessment. Washington, DC: The National Academies Press, 2011, pp. 4-5.
[7] Centers for Disease Control and Prevention. http://www.cdc.gov/healthyplaces/hia.htm. Accessed January 3, 2012.
[8] See also Environmental Conservation Law § 8-0103(5) ("…it is the intent of the legislature that the government of the state take immediate steps to identify any critical thresholds for the health and safety of the people of the state and take all coordinated actions necessary to prevent such thresholds from being reached).
[9] Bhatia, R and Wernham, A. Integrating Human Health into Environmental Impact Assessment: An Unrealized Opportunity for Environmental Health and Justice. Environmental Health Perspectives. 2008;116(8): 991-1000.

which clearly specifies the mandate for a full characterization of the effects on human health. The National Academies of Science committee on HIA recommended: “improving the integration of health into EIA under NEPA and related state laws…[to] serve the mission of public health and the goals of HIA….[In order t]o ensure reasonable priority of health issues under NEPA, public-health agencies should be afforded a substantive role in the scoping and oversight of health-effects analysis in EIA, and health-effects analysis must be afforded resources commensurate with the task.[10]

There is precedent for performing formal HIAs for drilling activities. In 2007, an HIA of proposed oil and gas development projects in Alaska’s North Slope was performed by the local government.[11] The HIA evaluated predicted impacts on fish and wildlife and the consequences for diet and health in the local population. It also identified potential social changes such as drug and alcohol use. The HIA led to new requirements for air quality analysis and monitoring of any oil-related contaminants in subsistence foods, and to a new requirement for worker education on drugs, alcohol and sexually transmitted diseases.

A draft HIA was done in Colorado for a proposed gas drilling development in Battlement Mesa. This draft HIA identified eight major areas of health concern (stressors) associated with natural gas development and production: air emissions, water and soil contaminants, truck traffic, noise/light/vibration, health infrastructure, accidents and malfunctions, community wellness, and economics/employment.[12] Several physical health outcomes linked to potential exposures were considered, including respiratory, cardiovascular, cancer, psychiatric, and injury/motor vehicle-related impacts on vulnerable and general populations in the community. The study concluded: “The key findings of our study are that [the] health of the Battlement Mesa residents will most likely be affected by chemical exposures, accidents or emergencies resulting from industry operations and stress-related community changes.”[13] The researchers went on to recommend a set of mitigation measures to reduce the health threats to local residents. Although the Battlement Mesa HIA was halted by the local Board of County Commissioners, apparently for political reasons,[14] it demonstrated the feasibility and utility of HIA for evaluating risks to the health of local residents from hydraulic fracturing and natural gas drilling operations.

In October of 2011, hundreds of health professionals signed a letter to Governor Cuomo specifically requesting that the draft SGEIS be “supplemented to include a full assessment of the public health impacts of gas

[10] National Research Council. Improving Health in the United States: The Role of Health Impact Assessment. Washington, DC: The National Academies Press, 2011, p. 111-113.
[11] Wernham A. Building a Statewide Health Impact Assessment Program: A Case Study from Alaska. Northwest Public Health. Fall/Winter 2009; Health Impact Project. Case Study: Oil Development of Alaska’s North Slope. http://www.healthimpactproject.org/resources/case-study-oil-development-of-alaskas-north-slope. Accessed January 5, 2011.
[12] Witter R, McKenzie L, Towle M, et al. Health Impact Assessment for Battlement Mesa, Garfield County Colorado. Colorado School of Public Health, University of Colorado, Denver, September 2010. http://www.garfield-county.com/public-health/documents/1%20%20%20Complete%20HIA%20without%20Appendix%20D.pdf. Accessed January 4, 2012.
[13] Battlement Mesa Health Impact Assessment (2nd Draft). March 1, 2011. http://www.garfield-county.com/public-health/battlement-mesa-health-impact-assessment-draft2.aspx. Accessed January 4, 2012.
[14] Vote Ends work on Battlement Mesa HIA. May 4, 2011. http://www.healthimpactproject.org/news/in/vote-ends-work-on-battlement-mesa-hia. Accessed January 4, 2012.

exploration and production."[15] The letter pointed out that, "there is a growing body of evidence on health impacts from industrial gas development," and specifically stated that: "A comprehensive Health Impact Assessment (HIA) would be the most appropriate mechanism for this work." The Director of the Agency for Toxic Substances and Disease Registry (ATSDR), Dr. Christopher Portier, also supports more thorough assessment of the health impacts of gas drilling, stating: "Studies should include all the ways people can be exposed, such as through air, water, soil, plants and animals."[16]

In summary, the requirements of SEQRA and recommendations of the National Academies of Science argue strongly for the need for a New York HIA of the health impacts of gas drilling and hydraulic fracturing. A similar investigation in Colorado revealed a set of potentially significant human health impacts associated with chemical exposures, accidents, and stress-related community changes, all of which were insufficiently considered in the New York RDSGEIS. Without a full assessment and mitigation of the impacts of the risks, the health of New York State residents and communities is likely to suffer.

[15] Abramson A, Abrams J, Alexander M, et al. Letter to The Honorable Andrew M. Cuomo. October 5, 2011. http://www.psehealthyenergy.org/resources/view/198813. Accessed January 5, 2012.
[16] CDC scientist: tests needed on gas drilling impact. Associated Press. January 4, 2012. http://online.wsj.com/article/AP8338b702930849f49d22a5d96b7d1b2d.html. Accessed January 5, 2012.

Attachment 11

Briana Mordick

January 10, 2012

To: Kate Sinding

From: Briana Mordick

Subject: Technical analysis of hydraulic fracturing-induced seismicity provisions in the New York State Revised Draft Supplemental Generic Environmental Impact Statement On the Oil, Gas & Solution Mining Regulatory Program

Introduction

The following report is a technical review and analysis of the hydraulic fracturing-induced seismicity provisions of the New York State (NYS) 2011 Revised Draft Supplemental Generic Environmental Impact Statement (RDSGEIS) on the Oil, Gas & Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs. This report includes recommendations for properly managing the risks associated with induced seismicity.

Analysis

The RDSGEIS fails to require operators of HVHF wells to consider the risk of induced seismicity when siting wells and designing hydraulic fracture treatments, concluding that,

"There is a reasonable base of knowledge and experience related to seismicity induced by hydraulic fracturing. Information reviewed indicates that there is essentially no increased risk to the public, infrastructure, or natural resources from induced seismicity related to hydraulic fracturing. The microseisms created by hydraulic fracturing are too small to be felt, or to cause damage at the ground surface or to nearby wells. Accordingly, no significant adverse impacts from induced seismicity are expected to result from high-volume hydraulic fracturing operations."[1]

Since the RDSGEIS was written, hydraulic fracturing has been confirmed to have caused induced seismicity strong enough to be felt at the surface. In a report commissioned by United Kingdom-based Cuadrilla Resources, researchers concluded that a series of earthquakes in Lancashire, UK were likely caused by hydraulic fracturing. Two relatively large earthquakes, with magnitudes 2.3 and 1.5, and 48 smaller events occurred in the hours after several stages of the Preese Hall 1 well were fracked.[2] A separate report written by a seismologist at the Oklahoma Geological Survey concluded that a swarm of about 50 earthquakes in Garvin County, Oklahoma, ranging in magnitude from 1.0 to 2.8, could also have been induced by hydraulic fracturing.[3]

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[1] Revised Draft SGEIS 2011, Executive Summary, Page 19

[2] de Pater, C.J., and Baisch, S., 2011, *Geomechanical Study of Bowland Shale Seismicity: Synthesis Report*, prepared for Cuadrilla Resources Ltd, 71p., available at: http://www.cuadrillaresources.com/cms/wp-content/uploads/2011/12/Final_Report_Bowland_Seismicity_02-11-11.pdf

[3] Holland, A., 2011, *Examination of Possibly Induced Seismicity from Hydraulic Fracturing in the Eola Field, Garvin County, Oklahoma*, Oklahoma Geological Survey, Open-File Report OF1-2011, 31p., available at: http://www.ogs.ou.edu/pubsscanned/openfile/OF1_2011.pdf

The RDSGEIS concedes that, "There are no seismic monitoring protocols or criteria established by regulatory agencies that are specific to high volume hydraulic fracturing,"[4] and recognizes that, "It is important to avoid injecting fluids into known, significant, mapped faults when hydraulic fracturing."[5] However, instead of developing such protocols and requiring operators to demonstrate that they have accounted for seismic risks in the siting of wells and design of hydraulic fracture treatments, the RSDGEIS assumes that, "Generally, operators would avoid faults because they disrupt the pressure and stress field and the hydraulic fracturing process,"[6] and, "It is in the operator's best interest to closely control the hydraulic fracturing process to ensure that fractures are propagated in the desired direction and distance and to minimize the materials and costs associated with the process."[7]

To justify why no additional analysis or monitoring is required to prevent induced seismicity, the RDSGEIS states, "The routine microseismic monitoring that is performed during hydraulic fracturing serves to evaluate, guide, and control the process and is important in optimizing well treatments,"[8] and, "Monitoring beyond that which is typical for hydraulic fracturing does not appear to be warranted, based on the negligible risk posed by the process and very low seismic magnitude."[9] However, earlier in the document, NYSERDA's consultant ICF International concludes that, "…fracture monitoring by [microseismic fracture mapping] is **not regularly used** because of cost…"[10] So in fact, seismic monitoring would rarely be employed during a routine hydraulic fracture treatment.

The RDSGEIS further assumes that no additional analysis of seismic risk is needed due to the fact that, "The locations of major faults in New York have been mapped (Figure 4.13) and few major or seismically active faults exist within the fairways for the Marcellus and Utica Shales."[11] There are two fatal flaws with this assumption. First, in both the UK and Oklahoma incidents, the earthquakes likely occurred due to slippage on minor, sub-seismic faults. Therefore, knowing the locations of only "major faults" is not sufficient to assess the potential risk of induced seismicity from hydraulic fracturing. Second, it is precisely the injection of fluids which induces previously inactive faults to become active. Therefore, whether a fault is currently or even recently seismically active is not sufficient to predict whether it could become active due to human activity – the definition of induced seismicity. A paper on earthquake hazards from deep well injection prepared by the U.S. Geological Survey for the U.S. Environmental Protection Agency concludes that predicting and mitigating seismic hazard risks in the Eastern United States is particularly problematic, as the causes of natural earthquakes and location of faults are not well understood.[12]

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[4] Revised Draft SGEIS 2011, Page 6-322
[5] Id.
[6] Id.
[7] Revised Draft SGEIS 2011, Page 6-323
[8] Revised Draft SGEIS 2011, Page 6-323
[9] Revised Draft SGEIS 2011, Page 6-328
[10] Revised Draft SGEIS 2011, Page 5-88, emphasis added
[11] Revised Draft SGEIS 2011, Page 6-327
[12] Nicholson, C., and Wesson, R., 1990, *Earthquake Hazard Associated With Deep Well Injection – A Report to the U.S. Environmental Protection Agency*, U.S. Geological Survey Bulletin 1951, 86p., available at: http://pubs.usgs.gov/bul/1951/report.pdf

Induced seismicity could result in unwanted and dangerous consequences, depending on the size and location of the earthquake. Fault movement may potentially endanger groundwater by creating or enhancing migration pathways between the zone being hydraulically fractured and underground sources of drinking water. Seismicity can also compromise wellbore integrity. The induced seismicity event in the UK caused ovalization of the production casing over hundreds of feet, with more than a half-inch of ovalization occurring over an approximately 250 foot length.[13] Such damage could compromise the cement bond, allowing methane or fluids to migrate up the back side of the casing to groundwater.

Even a relatively small earthquake could cause damage over a large area. The USGS report cited above states that, "Earthquakes in the Central and the Eastern United States typically cause damage over much larger areas as compared to earthquakes of the same size in the Western United States. This is primarily the result of the lower attenuation of seismic waves in the East versus the West, but other factors also may be involved."[14] Earthquakes could cause property damage including to private homes and public buildings and could also put at risk the aqueducts, tunnels, and infrastructure that deliver the New York City drinking water supply. In a report prepared for the New York City Department of Environmental Protection, environmental engineering firm Hazen and Sawyer concluded that, "…liner cracks can be anticipated to develop as the tunnels age, due to normal geologic activity (e.g., seismic activity), and to changes in subsurface conditions associated with widespread hydrofracturing, gas reservoir depletion/withdrawal and injection well operation," and, "Detrimental effects [to tunnel liners] could include liner cracks, which would facilitate infiltration of pressurized fluids."[15] In addition to natural seismic activity, induced seismicity could also be expected to create additional liner cracks. The authors also concluded that, "Hydraulic fracturing operations in proximity to the naturally occurring fracture systems that intersect DEP tunnels will increase the risk of (a) contaminating drinking water with drilling and fracturing chemicals and poor quality formation water; (b) methane accumulation around and within DEP subsurface infrastructure; and (c) tunnel liner structural failure. Mitigation of risks to drinking water quality and infrastructure integrity will require revision of current setback provisions to reflect the occurrence of laterally extensive subsurface faults, fractures, and brittle structures."[16] If earthquakes are induced along faults that intersect the DEP tunnels, these risks could be further exacerbated.

Even in the absence of actual damage, induced seismic events will have financial and manpower costs associated with the investigation of the causes and effects of the earthquake and from the suspension of operations until such studies are completed.

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[13] Id. at 2
[14] Id. at 13
[15] Hazen and Sawyer, 2009, *Impact Assessment of Natural Gas Production in the New York City Water Supply Watershed: Final Impact Assessment Report,* prepared for New York City Department of Environmental Protection, 100p., available at:
http://www.nyc.gov/html/dep/pdf/natural_gas_drilling/12_23_2009_final_assessment_report.pdf
[16] Id., Appendix D

The RDSGEIS provides insufficient analysis and scientific evidence to support its conclusion that regulations to reduce the risk of induced seismicity from hydraulic fracturing are not necessary.

Recommendation

The RDSGEIS should require operators to provide a site-specific analysis of the risk of induced seismicity due to hydraulic fracturing. This should include a detailed analysis of the geology, including the locations of known faults and an assessment of the seismic history of the region. Operators should be required to provide an analysis detailing the maximum magnitude of an earthquake that could be triggered based on anticipated injection volume and the probability that such an earthquake may occur based on site-specific geologic and geophysical parameters such as fault and fracture density, lithology, minimum horizontal stress, and anticipated pore pressure as a result of fluid injection.[17] Operators should then be required to use this data to properly design their hydraulic fracture treatment to reduce the risk of triggering induced seismicity. Operators should be required to perform seismic monitoring during hydraulic fracturing to ensure that any seismicity that occurs is within design parameters.

[17] See, e.g., Shapiro,S. A., C. Dinske, and J. Kummerow (2007), Probability of a given magnitude earthquake induced by a fluid injection, Geophys. Res. Lett., 34, L22314, doi:10.1029/2007GL031615.

Attachment 12

Expert Resumes

Harvey Consulting, LLC.

- Susan Harvey

Tom Myers, Ph.D.

Glenn Miller, Ph.D.

Ralph Seiler, Ph.D.

Meliora Design, LLC.

- Michele Adams, P.E.
- Ruth Sitler, P.E.

The Louis Berger Group, Inc.

- Niek Veraart, AICP, ASLA
- Raed EL-Farhan, Ph.D.
- Hope Luhman, Ph.D., RPA
- Edward Samanns, PWS, CE
- Leo Tidd
- Dane Ismart

Kevin Heatley

Kim Knowlton, DrPH

Gina Solomon, M.D.

Briana Mordick

HARVEY CONSULTING, LLC.

Oil & Gas, Environmental, Regulatory Compliance, and Training

Susan L. Harvey, Owner

Susan Harvey has 25 years of experience as a Petroleum and Environmental Engineer, working on oil and gas exploration and development projects. Ms. Harvey is the owner of Harvey Consulting, LLC, a consulting firm providing oil and gas, environmental, regulatory compliance advice and training to clients. Ms. Harvey held engineering and supervisory positions at both Arco and BP including Prudhoe Bay Engineering Manager and Exploration Manager. Ms. Harvey has planned, engineered, executed and managed both on and offshore exploration and production operations, and has been involved in the drilling, completion, stimulation, testing and oversight of hundreds of wells in her career. Ms. Harvey's experience also includes air and water pollution abatement design and execution, best management practices, environmental assessment of oil and gas project impacts, and oil spill prevention and response planning. During Governor Knowles Administration, Ms. Harvey headed the Industry Preparedness Program for the Alaska Department of Environmental Conservation, Division of Spill Prevention and Response; she was responsible for oil spill prevention and response oversight of all Alaska industry operations that produce, store or transport hydrocarbons. Ms. Harvey taught air pollution control engineering courses at the University of Alaska in the Graduate Engineering Program.

Education Summary:

Environmental Engineering
Masters of Science
University of Alaska Anchorage

Petroleum Engineering
Bachelor of Science
University of Alaska Fairbanks

Consulting Services:
- Oil and gas, environmental, regulatory compliance advice and training
- Oil spill prevention and response planning
- Air pollution assessment and control

Employment Summary:

2002-Current	Harvey Consulting, LLC., Owner
2005-Current	Harvey Fishing, LLC., Co-owner
2002-2007	University of Alaska at Anchorage Environmental Engineering Graduate Level, Adjunct Professor
1999-2002	State of Alaska, Department of Environmental Conservation Environmental Supervisory Position
1996-1999	Arco Alaska Inc. Engineering and Supervisory Positions held
1989-1996	BP Exploration (Alaska), Inc. Environmental, Engineering, and Supervisory Positions held
1987-1989	Standard Oil Production Company *(purchased by BP in 1989)*, Engineering Position
1985-1986	Conoco, Production Engineer and New Mexico Institute of Mining and Technology Petroleum Research & Recovery Center, Laboratory Research Assistant

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Harvey Consulting, LLC
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Employment Detail:

2002-Current **Harvey Consulting, LLC.**
Owner of consulting business providing oil and gas, environmental, regulatory compliance and training to clients.

2005-Current **Harvey Fishing, LLC.**
Co-owner and operator of a commercial salmon fishing business in Prince William Sound Alaska.

2002-2007 **University of Alaska at Anchorage**
Environmental Engineering Graduate Level Program, Adjunct Professor Air Pollution Control.

1999-2002 **State of Alaska, Department of Environmental Conservation**
Environmental Supervisory Position
Industry Preparedness and Pipeline Program Manager, Alaska Department of Environmental Conservation, Division of Spill Prevention and Response. Managed 30 staff in four remote offices. Main responsibility was to ensure all regulated facilities and vessels across Alaska submitted high quality Oil Discharge Prevention and Contingency Plans to prevent and respond to oil spills. Staff included field and drill inspectors, engineers, and scientists. Managed all required compliance and enforcement actions.

1996-1999 **Arco Alaska Inc.**
Engineering and Supervisory Positions held
Prudhoe Bay Waterflood and Enhanced Oil Recovery Engineering Supervisor. Main responsibility was to set the direction for a team of engineers to design, optimize and manage the production over 120,000 barrels of oil per day from approximately 400 wells and nine drill sites, from the largest oil field in North America. Responsible for six concurrently operating drilling and workover rigs.

Prudhoe Bay Satellite Exploration Engineering Supervisor for development of six new Satellites Oil Fields. Main responsibility was to set the direction for a multidisciplinary team of Engineers, Environmental Scientists, Facility Engineers, Business Analysts, Geoscientists, Land, Tax, Legal, and Accounting. Responsible for two appraisal drilling rigs.

Lead Engineer for Arco Western Operating Area Development Coordination Team. Lead a multi-disciplinary team of engineers and geoscientists, working on the Prudhoe Bay oil field.

1989-1996 **BP Exploration (Alaska), Inc.**
Environmental, Engineering, and Supervisory Positions held
Senior Engineer Environmental & Regulatory Affairs Department. Main responsibilities included: air quality engineering, technical and permitting support for Northstar, Badami, Milne Point Facilities and Exploration Projects.

Senior Engineer/Litigation Support Manager. Duties included managing a multidisciplinary litigation staff to support the ANS Gas Royalty Litigation, Quality Bank Litigation and Tax Litigation. Main function was to coordinate, plan and organize the flow of work amongst five contract attorneys, seven in-house attorneys, two technical consultants, eight expert witnesses, four in-house consultants and twenty-two staff members.

Senior Planning Engineer. Provided technical, economic, and negotiations support on Facility, Power, Water and Communication Sharing Agreements. Responsibilities also included providing technical assistance on recycled oil issues, ballast water disposal issues, chemical treatment options, and contamination issues.

Production Planning Engineer. Coordinated State approval of the Sag Delta North Participating Area and Oil Field. Resolved technical, legal, tax, owner and facility sharing issues. Developed an LPG feasibility study for the Endicott facility.

Reservoir Engineer. Developed, analyzed and recommended options to maximize recoverable oil reserves for the Endicott Oil Field through 3D subsurface reservoir models, which predicted fluid movements and optimal well placement for the drilling program. Other duties included on-site wellbore fluid sampling and subsequent lab analysis.

Production Engineer. North Slope field engineering. Duties included design and implementation of wireline, electric line, drilling and rig completions, well stimulation, workovers and well testing programs.

1987-1989 **Standard Oil Production Company, Production Engineer**

Production Engineer. North Slope field engineering. Duties included design and implementation of wireline, electric line, drilling and rig completions, well stimulation, workovers and well testing programs.

Engineering Internship, Barry Waterflood Oklahoma City OK.

1986 **Conoco, Production Engineer**

Production Engineer. Engineering Internship, Hobbs New Mexico.

1985-1986 **New Mexico Institute of Mining and Technology**
Petroleum Research & Recovery Center

Laboratory Research Assistant, Enhanced Oil Recovery, Surfactant Research.

<u>Harvey Consulting, LLC, Major Projects and Publications</u>

Northeast Natural Energy, LLC. and Enrout Properties, LLC vs. The City of Morgantown, West Virginia, technical support to The City of Morgantown, 2011.

Arctic Oil and Gas Project, technical support to Pew Charitable Trust, 2010-2011.

Stockport Mountain Corporation, LLC vs. Norcross Wildlife Foundation, Inc., technical support to Norcross Wildlife Foundation, Inc., 2011.

Nikaitchuq Oil and Gas Development Project, technical review and advice to North Slope Borough, 2011.

Valdez Marine Terminal, Oil Spill Prevention Audit, report prepared for Prince William Sound Regional Citizens Advisory Council, 2011.

Great Bear Petroleum Exploration Oil Spill Prevention and Response Plan, technical review and comments prepared for North Slope Borough, 2011.

Recommendations to Improve the December 9, 2010 Delaware River Basin Commission (DRBC) Proposed Natural Gas Development Regulations, report prepared for Delaware Riverkeeper Network, 2011.

Oooguruk Oil and Gas Development Project, technical review and advice to North Slope Borough, 2011.

Trans-Alaska Pipeline Oil Discharge Prevention and Contingency Plan, technical review and comments prepared for North Slope Borough, 2011

Shell Beaufort Sea Exploration Plan, technical support to North Slope Borough, 2007-2011.

Canadian National Energy Board, Offshore Drilling Review, technical support to WWF-Canada, 2011.

Shell Chukchi Sea Exploration Plan, technical support to North Slope Borough, 2010-2011.

SINTEF Behavior of Oil and Other Hazardous and Noxious Substances (HNS) spilled in Arctic Waters (BoHaSA) Report, technical review and advice to WWF, 2011.

Milne Point Oil & Gas Project, technical review and advice to North Slope Borough, 2011

National Commission Report on the BP Deepwater Horizon Oil Spill and Offshore Drilling, the Challenges of Oil Spill Response in the Arctic, technical analysis and recommendations prepared for Pew Charitable Trust, 2010.

Appeal of U.S. Forest Service Plan of Operations Denial for Wolcott Gold Mining Operation, technical report and appeal filing for Wolcott Gold Mining, 2010.

Valdez Marine Terminal Oil Spill Prevention and Response, technical support Prince William Sound Regional Citizens Advisory Council, 2002-2011.

Environmental Impacts and Regulation of Natural Gas Production, E2 Environmental Entrepreneurs, Presentation, 2011.

Petroleum and Natural Gas Systems, Subpart W, Mandatory Reporting of Greenhouse Gases, technical support to Natural Resources Defense Council and Sierra Club, 2010-2011.

Delaware River Basin Commission (DRBC) Consolidated Administrative Hearing on Grandfathered Exploration Wells, report prepared for Delaware Riverkeeper Network, 2010.

Recommendations for Australian Government Commission of Inquiry Montara Well Head Platform Uncontrolled Hydrocarbon Release, - Final Findings Document Post Commission of Inquiry Proceedings, report prepared for World Wide Fund for Nature Australia, 2010.

Gas Well Risk Management Controls, Protection of Groundwater Resources and Safe Well Construction, Operation and Abandonment, analysis prepared for Environmental Defense Fund and Sierra Club, 2010.

Recommendations for Pennsylvania's Proposed Changes to Oil and Gas Well Construction Regulations, report prepared for Earthjustice and Sierra Club, 2010

Ohio Senate Bill 165 Implementation Workgroup, revised Oil and Gas Standards for Ohio, Engineering Support to Environmental Defense Fund and Sierra Club, 2010.

New York State (NYS) Casing Regulation Recommendations, report prepared for Natural Resources Defense Council, 2009.

2011 Arctic Oil & Gas General NPDES Permit (Arctic GP) Heavy Metal Discharges (Mercury and Cadmium) in Drilling Muds and Cuttings, report to North Slope Borough, 2010.

Onshore Seismic Exploration Best Practices & Model Permit Requirements, report prepared for Natural Resources Defense Council, 2010.

Comparison of 2009 Timor Sea Well blowout to Gulf of Mexico Well blowout, report prepared for World Wide Fund for Nature Australia, 2010.

Recommendations for Profitable Greenhouse Gas Reductions from Oil and Gas Facilities in New Mexico, report to Natural Resources Defense Council, 2010.

EPA's Proposed Reissuance of Arctic Offshore NPDES Permit for Facilities Related to Oil and Gas Extraction, technical advice to the North Slope Borough, 2009-2010.

Oil & Gas Exploration and Production Operations Inspector Training and Manual, prepared for North Slope Borough, 2010.

Crude Oil Storage Tank 14, American Petroleum Institute Tank Inspection Record Review, Audit and Corrosion Calculations, report prepared for Prince William Sound Regional Citizens Advisory Council, 2010.

Minerals Management Service Outer Continental Shelf Five Year Oil and Gas Leasing Program 2012-2017, comments prepared for Aleutians East Borough, 2010.

Alaska Regional Response Team Dispersant Use Guideline Revision Workgroup, technical support for the North Slope Borough, 2009-2010.

Alaska Oil and Gas Conservation Commission Proposed Regulation Changes, Title 20, Chapter 25, Alaska Administrative Code Annular Disposal of Drilling Waste, technical review and comments prepared for North Slope Borough, 2010.

Outer Continental Shelf, Oil & Gas Lease Sale, North Aleutian Basin, Cooperating Agency, technical support to Aleutians East Borough, 2009.

Review of Shell Exploration and Production Company's August 2008 Analysis of the Pros and Cons of Zero Discharge of Muds and Cuttings During Exploration Drilling in the Alaska Beaufort Sea Outer Continental Shelf, and Shell's May 2009 Supplemental Information on Annular Injection and Barents Sea Exploration Permits, report to North Slope Borough, 2009.

Best Management Practices for Cementing and Casing, analysis prepared for Earthjustice, 2010.

Recommendations for Australian Government Commission of Inquiry Montara Well Head Platform Uncontrolled Hydrocarbon Release- Initial Findings Document Prior to Commission of Inquiry Proceedings, report prepared for World Wide Fund for Nature Australia, 2010.

Alaska Oil and Gas Conservation Commission Proposed Regulation Changes, Title 20, Chapter 25, Alaska Administrative Code Well Safety Valve System Requirements, technical review and comments prepared for North Slope Borough, 2010.

Analysis and Recommendations on Shell Oil's Beaufort Sea Exploration Program, analysis prepared for Pew Charitable Trusts, 2010.

Comments to EPA on Proposed Mandatory Reporting of Greenhouse Gas: Petroleum and Natural Gas Systems - Docket EPA-HQ-OAR-2009-0923, prepared for Clean Air Task Force, Environmental Defense Fund, Natural Resources Defense Council, Sierra Club, 2010

Draft Supplemental Generic Environmental Impact Statement On the Oil, Gas & Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low-Permeability Gas Reservoirs, Review of DSGEIS and Identification of Best Technology and Best Practice Recommendations, report prepared for Natural Resources Defense Council, 2009.

Commercial Recreation Operations, permit applications, standards, and model stipulations prepared for North Slope Borough, 2008-2010.

North Slope Village Residential and Commercial Operations, permit applications, standards, and model stipulations prepared for North Slope Borough, 2008-2010.

Alaska Coastal Impact Assistance Program Grant Applications for Seismic, LNG, and Resource Development Projects, prepared for the Aleutians East Borough, 2009-2010.

Oil & Gas Exploration and Production Operations, permit applications, standards, and model stipulations prepared for North Slope Borough, 2008-2010.

Outer Continental Shelf, Oil & Gas Lease Sale, North Aleutian Basin, Mitigation Measure Recommendations, report prepared for the Aleutians East Borough, 2009.

ExxonMobil Point Thomson Exploration Drilling Operations, reports and technical advice to North Slope Borough, 2008-2010.

Oil & Gas Assembly Workshop, conducted for Aleutians East Borough, 2009.

IHLC Historical Site Protection During Oil & Gas Exploration and Production Operations, permit applications, standards, and model stipulations prepared for North Slope Borough, 2008-2010.

Western Climate Initiative (WCI) Working Group on Oil and Gas, technical support to Natural Resources Defense Council, 2009-2010.

Alyeska Pipeline Service Company, Ship Escort Response Vessel System, Audit of Fishing Vessel Readiness to Support a Catastrophic Tanker Spill, report prepared for Prince William Sound Regional Citizens Advisory Council, 2009

Western Regional Air Partnership (WRAP) Working Group on Oil and Gas Exploration & Production (E&P) Greenhouse Gas (GHG) Accounting Protocol, technical support to Natural Resources Defense Council, 2009-2010.

Oil Spill Prevention and Response Improvements for Oil and Gas Exploration and Production in Alaska's North Slope, and Chukchi and Beaufort Seas, recommendations prepared for the North Slope Borough, 2010.

Beechey Point Unit Oil and Gas Master Plan and Proposed Amendment to the Official Zoning Map to Rezone all Lands Needed for Development of the Beechey Point Unit to Resource Development, recommendation prepared for the North Slope Borough, 2010.

Audit of July 2010 Valdez Marine Terminal Surprise Drill, Personnel Availability, Training and Qualifications, report prepared for Prince William Sound Regional Citizens Advisory Council, 2010.

CGGVeritas, Inc. Onshore and Offshore 3D Seismic Data Plan, technical review completed for the North Slope Borough, 2010.

Crude Oil Storage Tank 10, American Petroleum Institute Tank Inspection Record Review, Audit and Corrosion Calculations, report prepared for Prince William Sound Regional Citizens Advisory Council, 2010.

Brooks Range Petroleum Company Northshore Oil Development Project, technical review completed for the North Slope Borough, 2009.

Oil & Gas Comprehensive Plan, technical advice to the North Slope Borough, 2009-2011.

ConocoPhillips Chukchi Sea Exploration Plan, technical review completed for the North Slope Borough, 2008.

Brooks Range Petroleum Company Northshore Development Project, technical review completed for the North Slope Borough, 2009.

Industrial Waste Water System and Manhole Repairs in Secondary Containment System, Valdez Marine Terminal, technical advice to Prince William Sound Regional Citizens Advisory Council, 2009.

North Slope Oil Spills, technical support and advice to the North Slope Borough on a variety of actual oil spills, 2002-2011.

Tract 75 Contaminated Site, technical advice to the North Slope Borough, 2009-2010.

Strategic Plan for Retaining Crude Oil Tanker Tug Escorts for Prince William Sound, plan prepared for Prince William Sound Regional Citizens Advisory Council, 2009.

Arctic Technologies Workshop - Key Learnings, report prepared for the Aleutians East Borough, 2009.

Not So Fast: Some Progress in Spill Response, but US Still Ill-Prepared for Arctic Offshore Development, A review of US Department of the Interior, Minerals Management Service's (MMS) Arctic Oil Spill Response Research and Development Program – A Decade of Achievement, report prepared for World Wildlife Fund, 2009.

Environmental Liability Baseline Assessment for Crazy Horse Oilfield Pad, technical review and recommendation prepared for the North Slope Borough, 2009.

Valdez Marine Terminal Oil Spill Prevention Audit, report prepared for Prince William Sound Regional Citizens Advisory Council, 2009.

EPA's Proposed Reissuance of General NPDES Permit for Facilities Related to Oil and Gas Extraction, comments prepared for the North Slope Borough, 2009.

Cape Simpson Oil Spill and Contaminated Site: Cleanup Action Requested, technical advice to the North Slope Borough, 2009-2010

Particulate Matter Emissions from In Situ Burning of Oil Spills, Alaska's In Situ Burning Guidelines, technical advice and comments prepared for Prince William Sound Regional Citizens Advisory Council, 2009

Arctic Multiple Oil and Gas Lease Sale for the Beaufort and Chukchi Seas, technical review and comments prepared for the North Slope Borough, 2008.

Current Offshore Waste Disposal Regulations, Permitting Process and Practices in Alaska Waters from Exploration and Production Operations, report prepared for the North Slope Borough, 2008.

Liberty Offshore Oil Production Plan, technical review for the North Slope Borough, 2008.

Northeast National Petroleum Reserve Alaska, Lease Sale Environmental Impact Statement and Lease Sale, technical support for Cooperating Agency participation in EIS preparation for the North Slope Borough, 2007-2008.

Oliktok Point Dredging Permit, technical review for the North Slope Borough, 2008.

Kuparuk Seawater Treatment Plant, Waterflood Operations, technical review for the North Slope Borough, 2008.

Lisburne Oil Production Facility Secondary Containment for Hydrocarbon Storage, technical review for the North Slope Borough, 2008.

Alpine Oil Development Oil Discharge Prevention and Contingency plan, technical review completed for support for the North Slope Borough, 2008.

UltraStar Exploration Drilling Program, technical review completed for the North Slope Borough, 2008.

EPA Vessel Discharge General Permit AK0808-13AA, comments prepared for Prince William Sound Regional Citizens Advisory Council related to crude oil tankers, 2008.

Ooguruk Oil Production Facility Development Plan, technical review for the North Slope Borough, 2008.

MMS Pipeline Regulations, Proposed Revisions to 30 CFR Part 250, 253, 254, 256, Oil and Gas and Sulfur Operations in the OCS – Pipelines and Pipeline Rights-of-Way, recommendations and comments prepared for North Slope Borough, 2008.

Valdez Marine Terminal Oil Spill Prevention and Contingency Plan, comments prepared for Prince William Sound Regional Citizens Advisory Council, 2008.

Alpine Oil Development Master Plan Rezone Application, technical advice and reports to the North Slope Borough, 2006-2008.

Prudhoe Bay Oil Production Facility Reserve Pit Closures and Pad Abandonment, technical advice and reports to the North Slope Borough, 2008.

Strategic Plan for the NSB Wildlife Department, plan prepared for North Slope Borough, 2008.

Revision to Title 19, Oil and Gas Land Use Ordinance, recommendations prepared for the North Slope Borough, 2008-2010.

Shell Offshore Exploration Plan, Air Permit Appeal to Environmental Appeals Board and 9th Circuit Court, technical advice and reports to the North Slope Borough, 2008-2009.

Oil and Gas Infrastructure Risk Assessment for Alaska, comments prepared for the North Slope Borough, 2008.

Crude Oil Storage Tanks 9 & 10, Notice of Violation, Breach in Secondary Containment, Valdez Marine Terminal, technical advice to the Prince William Sound Regional Citizens Advisory Council, 2008.

Oil and Gas Facilities Operating on North Slope of Alaska, Air Pollution Inventory, prepared for the North Slope Borough, 2008.

Oil Spill Prevention and Response Training, conducted for the North Slope Borough, 2006-2010.

Coville Tank Farm Oil Discharge Prevention and Contingency Plan, technical review and comments prepared for the North Slope Borough, 2008.

Northstar Oil Facility Inspection and Audit, completed for the North Slope Borough, 2008.

XTO Energy Oil Discharge Prevention and Response Plan, prepared for XTO Energy's Cook Inlet Oil and Gas Production Operations, 2007.

Prudhoe Bay Oil Production Facility Flare Upgrade, technical review for the North Slope Borough, 2008.

Alpine Oil Facility Air Permit, comments prepared for the North Slope Borough, 2008.

BHP Billiton Tundra Damage and Spill Notices of Violation, technical advice to the North Slope Borough, 2008.

Kuparuk Oil Discharge Prevention and Contingency Plan, technical review and comments prepared for the North Slope Borough, 2007.

Meltwater Oil Production Operations, inspection and audit completed for support for the North Slope Borough, 2007.

Renaissance Umiat, LLC., Northeast National Petroleum Reserve- Alaska Exploration Program, technical review prepared for the North Slope Borough, 2007.

Ballast Water Treatment Facility Abatement of Hazardous Air Pollution, at Valdez Marine Terminal, technical advice and reports for Prince William Sound Regional Citizens Advisory Council, 2005-2009.

U.S. States Court of Appeals for the Ninth Circuit, Northwest Environmental Advocates, et al., Plaintiffs-Appellees; Petitioners, and the States of New York, et al. Plaintiff-Intervenors Appellees.-v.- US EPA Defendant-Appellant; Respondent and the Shipping Industry Ballast Water Coalition, Defendant-Intervenor Appellant, on Appeal from the US District Court for the Northern District of California, Brief of Amicus Curiae, for the Aleutians East Borough, technical support for Aleutians East Borough filing prepared by Walker and Levesque, LLC., 2006-2007.

Chevron North America Exploration and Production, North Slope Exploration Program "White Hills", technical advice and reports to the North Slope Borough, 2007.

City of Valdez Oil & Gas Tax Appeal, technical support to Walker & Levesque, LLC., 2006-2007.

Conoco Phillips Proposed Ultra Low Sulfur Diesel Facility, at Kuparuk River Unit CPF-3, technical analysis and recommendation prepared for North Slope Borough, 2006.

Application of Norway's Best Practices for Oil & Gas Operations to US Arctic Operations, report prepared for the North Slope Borough, 2008.

Air Strippers and Regenerative Thermal Oxidizers, proposal to install at Valdez Marine Terminal, technical review for Prince William Sound Regional Citizens Advisory Council, 2008.

Northstar Air Permit, technical review and comments prepared for the North Slope Borough, 2007.

Nikaitchuq Oil Development Plan, technical review completed for support for the North Slope Borough, 2006-2009.

Aleutians East Borough Title 40, Planning, Platting and Land Use Code Revision for Oil and Gas Exploration and Production Operations, technical advice to Aleutians East Borough, 2006-2007.

Natural Gas LNG North Slope Facility Proposal, technical review completed for support for the North Slope Borough, 2006.

Milne Point Unit Oil Discharge Prevention and Contingency Plan, technical review and comments prepared for the North Slope Borough, 2006.

Oooguruk Oil Production Facility Air Permit and Oil Spill Plan, technical review for the North Slope Borough, 2006.

Crude Oil Storage Tank 5, Alleged Integrity Concerns Preliminary Investigation, Valdez Marine Terminal, reports prepared for the Prince William Sound Regional Citizens Advisory Council, 2006 and 2007.

Proposed Changes to 11 AAC 83 Bonds and Plans for Dismantlement, Removal and Restoration of Oil and Gas Facilities, technical review and comments prepared for the North Slope Borough, 2006.

Non-indigenous Species Control Options and Risks Associated with Crude Oil Tanker Traffic, database of all technical and regulatory publications and research available, prepared for Prince William Sound Regional Citizens Advisory Council, 2006

Prudhoe Bay Oil Discharge Prevention and Contingency Plan, technical review and comments prepared for the North Slope Borough, 2006.

Petro-Canada (Alaska) Inc., Western NPR-A Exploration Drilling Program, technical review prepared for the North Slope Borough, 2006.

Crude Oil Storage Tank 16, Alleged Integrity Concerns Preliminary Investigation, Valdez Marine Terminal, report prepared for the Prince William Sound Regional Citizens Advisory Council, 2006.

DOT Pipeline Safety: Protecting Unusually Sensitive Areas from Rural Onshore Hazardous Liquid Gathering lines and Low-Stress Lines, comments prepared for the North Slope Borough, 2006.

Nikaitchuq Air Permit, technical review and comments prepared for the North Slope Borough, 2006.

Prince William Sound Oil Tanker Spill Prevention and Contingency Plan, comments prepared for Prince William Sound Regional Citizens Advisory Council, 2007.

EPA's Proposed Regulations for Development of Clean Water Act National Pollutant Discharge Elimination System Permits for Discharges Incidental to the Normal Operation of Vessels, comments prepared for the North Slope Borough, 2007.

Fuel Storage Tank 55, Alleged Integrity Concerns Preliminary Investigation, Valdez Marine Terminal, report prepared for the Prince William Sound Regional Citizens Advisory Council, 2006.

Oil & Gas Exploration and Production Economic Opportunities and Capacity Building, report to the Aleutians East Borough, 2005.

Kuparuk Oil Facility Inspection and Audit, completed for the North Slope Borough, 2007.

Balboa Bay Regional Port Study Concept, LNG Tanker Terminal, prepared for Aleutians East Borough, 2007.

Alpine Oil Facility Inspection and Audit, completed for the North Slope Borough, 2007.

Surface Coal Mining Control and Reclamation Act Proposed Draft Regulations Title 11, Alaska Administrative Code, Chapter 90 (11 AAC 90), technical review and comments prepared for the North Slope Borough, 2007.

Crude Oil Storage Tank 93, Alleged Integrity Concerns Preliminary Investigation, Valdez Marine Terminal, reports prepared for the Prince William Sound Regional Citizens Advisory Council, 2006.

DeCola, E., T. Robertson, S. Fletcher, and S. Harvey, Offshore Oil Spill Response in Dynamic Ice Conditions: A Report to WWF on Considerations for the Sakhalin II Project, report to the World Wildlife Fund, 2006.

Savant Alaska, LLC Kupcake Prospect 2007 Exploration Well East of Endicott, technical advice to the North Slope Borough, 2005.

Prince William Sound Oil Tanker Tug Fleet Workshop and report, prepared for Prince William Sound Regional Citizens Advisory Council, 2006.

Crude Oil Storage Tank 1, American Petroleum Institute Tank Inspection Record Review, Audit and Corrosion Calculations, report prepared for Nuka Research and Planning Group, LLC., 2006.

Analysis of 1995-2005 Oil and Gas Facility Oil Spills on the North Slope of Alaska, report prepared for North Slope Borough, 2005.

Endicott and Badami Oil Discharge Prevention and Contingency Plan, technical review and comments prepared for the North Slope Borough, 2004.

Alpine Satellite Oil Development at CD-5, Bridge Construction and Pad Development, technical advice to the North Slope Borough, 2006-2008.

Valdez Marine Terminal, 203,000 Barrel Oil Spill Drill Evaluation, report prepared for Prince William Sound Regional Citizens Advisory Council, 2006.

Oil and Gas Bond Regulations, Proposed Changes to 11 AAC 83, comments prepared for the Aleutians East Borough, 2006.

Oil & Gas Lease Sales Brochure, prepared for the Aleutians East Borough, 2005.

Wastewater General Disposal Permit for Class I UIC Injection Wells, technical review and comments prepared for the North Slope Borough, 2005.

Oil & Gas Potential in the Aleutians East Borough, prepared for the Aleutians East Borough, 2005.

United States Air Force Oil Spill Response Training Manual and Training Program Implementation, prepared for and delivered to UASF under subcontract with Olgoonik Environmental Services, 2005-2007.

Oil and Gas Workshop, Cold Bay Alaska, conducted for the Aleutians East Borough, 2005.

Ballast Water Treatment Technology Options for Crude Oil Tankers, 15 Fact Sheets, prepared for Prince William Sound Regional Citizens Advisory Council, 2005

Alaska Peninsula Areawide Oil & Gas Lease Sale, Preliminary Best Interest Finding and Coastal Management Program Consistency Analysis, report prepared for the Aleutians East Borough, 2005.

Non-indigenous Species carried by Crude Oil Tankers into Prince William Sound, 17 Fact Sheets, prepared for Prince William Sound Regional Citizens Advisory Council, 2005

Armstrong Alaska, Inc. Oil Discharge Prevention and Contingency Plan for Rock Flour Prospect Drilling Program, technical review prepared for the North Slope Borough, 2005.

Proposed Changes to 18 AAC 75 Alaska's Oil and Hazardous Substances Pollution Control Regulations: Phase II Oil Spill Prevention, comments prepared for North Slope Borough, 2005-2006.

Preparing for Oil and Gas Development in the Aleutians East Borough: Potential benefits and impacts, prepared jointly under subcontract with Glenn Gray and Associates, for the Aleutians East Borough, 2005.

Minerals Management Service Outer Continential Shelf Five Year Oil and Gas Leasing Program 2007-2012, comments prepared for Aleutians East Borough, 2005.

Oil and Gas Economic Development, presentation to the Aleutian Pribilof Island Association, prepared for the Aleutians East Borough, 2005.

Valdez Marine Terminal Title V Air Quality Control Operating Permit No. 082TVP01, comments prepared for Prince William Sound Regional Citizens Advisory Council, 2005.

Proposed Changes to 18 AAC 75 Alaska's Oil and Hazardous Substances Pollution Control Regulations: Phase II Oil Spill Prevention, comments prepared for Prince William Sound Regional Citizens Advisory Council, 2005

Minerals Management Service Outer Continental Shelf Five Year Oil and Gas Leasing Program 2007-2012, comments prepared for North Slope Borough, 2005.

Oil and Gas Workshop, Nelson Lagoon Alaska, conducted for the Aleutians East Borough, 2005.

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Harvey, S. L., Final MACT Standards Issued for Iron and Steel Foundries, *Air Pollution Consultant*, Vol. 14, Issue 2, ISSN 1058-6628, 2004.

National Emission Standard for Hazardous Air Pollutants for Organic Liquid Distribution Facilities Petition for Review to EPA, prepared jointly with the Law Firm of Walker and Levesque, LLC. for Stan Stephens, 2004.

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Cook Inlet Oil and Gas Lease Sale, Report and Lease Sale Documents, prepared under subcontract to Petrotechnical Resource Associates, for the Alaska Trust Land Office for Public Lease Sale Offering of Lands for Oil and Gas Exploration on the West Side of Cook Inlet, 2003

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Trans-Alaska Pipeline System Pipeline Oil Discharge Prevention and Contingency Plan, comments prepared for Prince William Sound Regional Citizens Advisory Council, 2003

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Harvey, S.L., Federal Facility to Be Assessed "Economic Benefit" and "Size of Business" Penalty for CAA Violations, *Air Pollution Consultant*, Vol. 12, Issue 7, ISSN 1058-6628, 2002.

Prince William Sound Oil Tanker Spill Prevention and Contingency Plan, comments prepared for Prince William Sound Regional Citizens Advisory Council, 2002.

Valdez Marine Terminal Air Quality Oversight Project, report prepared for Prince William Sound Regional Citizens Advisory Council, 2002.

Tom Myers, Ph.D.
Consultant, Hydrology and Water Resources
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Reno, NV 89523
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Curriculum Vitae

Objective: To provide diverse research and consulting services to nonprofit, government, legal and industry clients focusing on groundwater modeling, hydrogeology, environmental forensics and compliance, NEPA analysis, federal and state regulatory review, fluvial morphology and environmental and water policy.

Education

Years	Degree	University
1992-96	Ph.D. Hydrology/Hydrogeology	University of Nevada, Reno Dissertation: Stochastic Structure of Rangeland Streams
1990-92		University of Arizona, Tucson AZ Classes in pursuit of Ph.D. in Hydrology.
1988-90	M.S. Hydrology/Hydrogeology	University of Nevada, Reno Thesis: Stream Morphology, Stability and Habitat in Northern Nevada
1981-83		University of Colorado, Denver, CO Graduate level water resources engineering classes.
1977-81	B.S., Civil Engineering	University of Colorado, Boulder, CO

Special Coursework

Years	Course	Sponsor
2011	Hydraulic Fracturing of the Marcellus Shale	National Groundwater Association
2008	Fractured Rock Analysis	MidWest Geoscience
2005	Groundwater Sampling Field Course	Nielson Environmental Field School
2004	Environmental Forensics	National Groundwater Association
2004 and -5	Groundwater and Environmental Law	National Groundwater Association

Professional Experience

Years	Position	Duties
1993-Pr.	Hydrologic Consultant	Surface, groundwater and systems modeling, hydrogeology studies, stream restoration design, watershed modeling studies and expert testimony for industry, nonprofit groups, and government agencies.
1999-2004	Great Basin Mine Watch Executive Director	Responsible for reviewing and commenting on mining projects with a focus on groundwater and surface water resources, preparing appeals and litigation, writing reports about mining, fundraising, organizational development, supervision and personnel management.
1992-1997	University of Nevada, Reno Research Associate	Research on riparian area and watershed management including stream morphology, aquatic habitat, cattle grazing and low-flow and flood hydrology.
1990-1992	University of Arizona, Tucson Research and Teaching Assistant	Research on rainfall/runoff processes and climate models. Taught lab sections for sophomore level "Principles of Hydrology". Received 1992 Outstanding Graduate Teaching Assistant Award in the College of Engineering
1988-1990	University of Nevada, Reno Research Assistant	Research on aquatic habitat, stream morphology and livestock management.
1983-1988	US Bureau of Reclamation, Boulder City, NV Hydraulic Engineer	Performed hydrology planning studies on topics including floodplains, water supply, flood control, salt balance, irrigation efficiencies, sediment transport, stream morphology, flood frequency, rainfall-runoff modeling and groundwater balances.
1981-1983	Faulkner-Kellogg and Assoc., Lakewood Co Design Engineer	Basic drainage, grading and subdivision design. Flood control studies.

Representative Reports, Presentations and Projects

Myers, T., 2011. Hydrogeology of Cave, Dry Lake and Delamar Valleys, Impacts of pumping underground water right applications #53987 through 53092. Presented to the Office of the Nevada State Engineer On behalf of Great Basin Water Network.

Myers, T., 2011. Hydrogeology of Spring Valley and Surrounding Areas, Part A: Conceptual Flow Model. Presented to the Nevada State Engineer on behalf of Great Basin Water Network and the Confederated Tribes of the Goshute Reservation.

Myers, T., 2011. Hydrogeology of Spring Valley and Surrounding Areas, Part B: Groundwater Model of Snake Valley and Surrounding Area. Presented to the Nevada State Engineer on behalf of Great Basin Water Network and the Confederated Tribes of the Goshute Reservation.

Myers, T., 2011. Hydrogeology of Spring Valley and Surrounding Areas, PART C: IMPACTS OF PUMPING UNDERGROUND WATER RIGHT APPLICATIONS #54003 THROUGH 54021. Presented to the Nevada State Engineer on behalf of Great Basin Water Network and the Confederated Tribes of the Goshute Reservation.

Myers, T., 2011. Rebuttal Report: Part 2, Review of Groundwater Model Submitted by Southern Nevada Authority and Comparison with the Myers Model. Presented to the Nevada State Engineer on behalf of Great Basin Water Network and the Confederated Tribes of the Goshute Reservation.

Myers, T. 2011. Rebuttal Report: Part 3, Prediction of Impacts Caused by Southern Nevada Water Authority Pumping Groundwater From Distributed Pumping Options for Spring Valley, Cave Valley, Dry Lake Valley, and Delamar Valley. Presented to the Nevada State Engineer on behalf of Great Basin Water Network and the Confederated Tribes of the Goshute Reservation.

Myers, T., 2011. Baseflow Selenium Transport from Phosphate Mines in the Blackfoot River Watershed Through the Wells Formation to the Blackfoot River, Prepared for the Greater Yellowstone Coalition.

Myers, T., 2011. Blackfoot River Watershed, Groundwater Selenium Loading and Remediation. Prepared for the Greater Yellowstone Coalition.

Myers, T., 2010. Planning the Colorado River in a Changing Climate, Colorado River Simulation System (CRSS) Reservoir Loss Rates in Lakes Powell and Mead and their Use in CRSS. Prepared for Glen Canyon Institute.

Myers, T., 2010. Technical Memorandum, Updated Groundwater Modeling Report, Proposed Rosemont Open Pit Mining Project. Prepared for Pima County and Pima County Regional Flood Control District

Myers, T., 2009. Monitoring Groundwater Quality Near Unconventional Methane Gas Development Projects, A Primer for Residents Concerned about Their Water. Prepared for Natural Resources Defense Council. New York, New York.

Myers, T., 2009. Technical Memorandum, Review and Analysis of the Hydrology and Groundwater and Contaminant Transport Modeling of the Draft Environmental Impact Statement Blackfoot Bridge Mine, July 2009. Prepared for Greater Yellowstone Coalition, Idaho Falls, Idaho.

Myers, T., 2008. Hydrogeology of the Carbonate Aquifer System, Nevada and Utah With Emphasize on Regional Springs and Impacts of Water Rights Development. Prepared for: Defenders of Wildlife, Washington, D.C.. June 1, 2008.

Myers, T., 2008. Hydrogeology of the Muddy River Springs Area, Impacts of Water Rights Development. Prepared for: Defenders of Wildlife, Washington, D.C. May 1, 2008

Myers, T., 2008. Hydrogeology of the Santa Rita Rosemont Project Site, Numerical Groundwater Modeling of the Conceptual Flow Model and Effects of the Construction of the Proposed Open Pit, April 2008. Prepared for: Pima County Regional Flood Control District, Tucson AZ.

Myers, T., 2008. Technical Memorandum, Review, Record of Decision, Environmental Impact Statement Smoky Canyon Mine, Panels F&G, U.S. Department of the Interior, Bureau of Land Management. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno NV.

Myers, T., 2007. Groundwater Flow and Contaminant Transport at the Smoky Canyon Mine, Proposed Panels F and G. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno NV. December 11, 2007.

Myers, T., 2007. Hydrogeology, Groundwater Flow and Contaminant Transport at the Smoky Canyon Mine, Documentation of a Groundwater Flow and Contaminant Transport Model. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno NV, December 7, 2007.

Myers, T., 2007. Review of Hydrogeology and Water Resources for the Final Environmental Impact Statement, Smoky Canyon Mine, Panels F and G and Supporting Documents. Prepared for Natural Resources Defense Council, San Francisco, CA and Greater Yellowstone Coalition, Idaho Falls, ID. Reno, NV. December 12, 2007.

Myers, T., 2007. Hydrogeology of the Powder River Basin of Southeast Montana Development of a Three-Dimensional Groundwater Flow Model. Prepared for Northern Plains Resource Council. February 12 2007.

Myers, T., 2007. Hydrogeology of the Santa Rita Rosemont Project Site, Conceptual Flow Model and Water Balance, Prepared for: Pima County Flood Control District, Tucson AZ

Myers, T., 2006. Review of Mine Dewatering on the Carlin Trend, Predictions and Reality. Prepared for Great Basin Mine Watch, Reno, NV

Myers, T., 2006. Hydrogeology of Spring Valley and Effects of Groundwater Development Proposed by the Southern Nevada Water Authority, White Pine and Lincoln County, Nevada. Prepared for Western Environmental Law Center for Water Rights Protest Hearing.

Myers, T., 2006. Potential Effects of Coal Bed Methane Development on Water Levels, Wells and Springs of the Pinnacle Gas Resource, Dietz Project In the Powder River Basin of Southeast Montana. Affidavit prepared for Northern Plains Resource Council, April 4 2006.

Myers, T., 2006. Review of Hydrogeology and Water Resources for the Draft Environmental Impact Statement, Smoky Canyon Mine, Panels F and G, Technical Report 2006-01-Smoky Canyon. Prepared for Natural Resources Defense Council.

Myers, T., 2006. Review of Nestle Waters North America Inc. Water Bottling Project Draft Environmental Impact Report / Environmental Assessment. Prepared for McCloud Watershed Council, McCloud CA.

Myers, T., 2005. Hydrology Report Regarding Potential Effects of Southern Nevada Water Authority's Proposed Change in the Point of Diversion of Water Rights from Tikapoo Valley South and Three Lakes Valley North to Three Lakes Valley South. Prepared for Western Environmental Law Center for Water Rights Protest Hearing

Myers, T., 2005. Review of Draft Supplemental Environmental Impact Statement, Ruby Hill Mine Expansion: East Archimedes Project NV063-EIS04-34, Technical Report 2005-05-GBMW. Prepared for Great Basin Mine Watch.

Myers, T., 2005. Hydrogeology of the Powder River Basin of Southeast Montana, Development of a Three-Dimensional Groundwater Flow Model. Prepared for Northern Plains Resource Council, Billings, MT in support of pending litigation.

Myers, T., 2005. Nevada State Environmental Commission Appeal Hearing, Water Pollution Control Permit

Renewal NEV0087001, Big Springs Mine. Expert Report. Prepared for Great Basin Mine Watch, Reno NV.

Myers, T., 2005. Potential Effects of Coal Bed Methane Development on Water Levels, Wells and Springs In the Powder River Basin of Southeast Montana. Prepared for Northern Plains Resource Council, Billings, MT.

Myers, T., 2004. An Assessment of Contaminant Transport, Sunset Hills Subdivision and the Anaconda Yerington Copper Mine, Technical Report 2004-01-GBMW. Prepared for Great Basin Mine Watch.

Myers, T., 2004. Technical Memorandum: Pipeline Infiltration Project Groundwater Contamination. Prepared for Great Basin Mine Watch.

Myers, T., 2004. Technical Report Seepage From Waste Rock Dump to Surface Water The Jerritt Canyon Mine, Technical Report 2004-03-GBMW. Prepared for Great Basin Mine Watch.

Myers, T., 2001. An Assessment of Diversions and Water Rights: Smith and Mason Valleys, NV. Prepared for the Bureau of Land Management, Carson City, NV.

Myers, T., 2001. Hydrogeology of the Basin Fill Aquifer in Mason Valley, Nevada: Effects of Water Rights Transfers. Prepared for the Bureau of Land Management, Carson City, NV.

Myers, T., 2001. Hydrology and Water Balance, Smith Valley, NV: Impacts of Water Rights Transfers. Prepared for the Bureau of Land Management, Carson City, NV

Myers, T., 2000. Alternative Modeling of the Gold Quarry Mine, Documentation of the Model, Comparison of Mitigation Scenarios, and Analysis of Assumptions. Prepared for Great Basin Mine Watch. Center for Science in Public Participation, Bozeman MT.

Myers, T., 2000. Environmental and Economic Impacts of Mining in Eureka County. Prepared for the Dept. Of Applied Statistics and Economics, University of Nevada, Reno.

Myers, T., 1999. Water Balance of Lake Powell, An Assessment of Groundwater Seepage and Evaporation. Prepared for the Glen Canyon Institute, Salt Lake City, UT.

Myers, T., 1998. Hydrogeology of the Humboldt River: Impacts of Open-pit Mine Dewatering and Pit Lake Formation. Prepared for Great Basin Mine Watch, Reno, NV.

Peer-Reviewed Publications

Myers, T., in review. Potential contaminant pathways from hydraulically fractured shale to aquifers. *Ground Water*.

Myers, T., 2009. Groundwater management and coal-bed methane development in the Powder River Basin of Montana. *J Hydrology* 368:178-193.

Myers, T.J. and S. Swanson, 1997. Variation of pool properties with stream type and ungulate damage in central Nevada, USA. *Journal of Hydrology* 201-62-81

Myers, T.J. and S. Swanson, 1997. Precision of channel width and pool area measurements. *Journal of the*

American Water Resources Association 33:647-659.

Myers, T.J. and S. Swanson, 1997. Stochastic modeling of pool-to-pool structure in small Nevada rangeland streams. *Water Resources Research* 33(4):877-889.

Myers, T.J. and S. Swanson, 1997. Stochastic modeling of transect-to-transect properties of Great Basin rangeland streams. *Water Resources Research* 33(4):853-864.

Myers, T.J. and S. Swanson, 1996. Long-term aquatic habitat restoration: Mahogany Creek, NV as a case study. *Water Resources Bulletin* 32:241-252

Myers, T.J. and S. Swanson, 1996. Temporal and geomorphic variations of stream stability and morphology: Mahogany Creek, NV. *Water Resources Bulletin* 32:253-265.

Myers, T.J. and S. Swanson, 1996. Stream morphologic impact of and recovery from major flooding in north-central Nevada. *Physical Geography* 17:431-445.

Myers, T.J. and S. Swanson, 1995. Impact of deferred rotation grazing on stream characteristics in Central Nevada: A case study. *North American Journal of Fisheries Management* 15:428-439.

Myers, T.J. and S. Swanson, 1992. Variation of stream stability with stream type and livestock bank damage in northern Nevada. *Water Resources Bulletin* 28:743-754.

Myers, T.J. and S. Swanson, 1992. Aquatic habitat condition index, stream type, and livestock bank damage in northern Nevada. *Water Resources Bulletin* 27:667-677.

Zonge, K.L., S. Swanson, and T. Myers, 1996. Drought year changes in streambank profiles on incised streams in the Sierra Nevada Mountains. *Geomorphology* 15:47-56.

Selected Abstracts, Magazine and Proceedings Articles

Myers, T., 2006. Modeling Coal Bed Methane Well Pumpage with a MODFLOW DRAIN Boundary. In MODFLOW and More 2006 Managing Ground Water Systems, Proceedings. International Groundwater Modeling Center, Golden CO. May 21-24, 2006.

Myers, T., 2006. Proceed Carefully: Much Remains Unknown, *Southwest Hydrology 5(3)*, May/June 2006, pages 14-16.

Myers, T., 2004. Monitoring Well Screening and the Determination of Groundwater Degradation, Annual Meeting of the Nevada Water Resources Association, Mesquite, NV. February 27-28, 2004.

Myers, T., 2001. Impacts of the conceptual model of mine dewatering pumpage on predicted fluxes and drawdown. In MODFLOW 2001 and Other Modeling Odysseys, Proceedings, Volume 1. September 11-14, 2001. International Ground Water Modeling Center, Golden, Colorado.

Myers, T., 1997. Groundwater management implications of open-pit mine dewatering in northern Nevada. In Kendall, D.R. (ed.), Conjunctive Use of Water Resources: Aquifer Storage and Recovery. AWRA Symposium, Long Beach California. October 19-23, 1997

Myers, T., 1997. Groundwater management implications of open-pit mine dewatering in northern Nevada. In Life in a Closed Basin, Nevada Water Resources Association, October 8-10, 1997, Elko, NV.

Myers, T., 1997. Uncertainties in the hydrologic modeling of pit lake refill. American Chemical Society Annual Meeting, Las Vegas, NV, Sept. 8-12, 1997.

Myers, T., 1997. Use of Groundwater modeling and geographic information systems in water marketing. In Warwick, J.J. (ed.), Water Resources Education, Training, and Practice: Opportunities for the Next Century. AWRA Symposium, Keystone, Colo. June 29-July 3, 1997.

Myers, T., 1995. Decreased surface water flows due to alluvial pumping in the Walker River valley. Annual Meeting of the Nevada Water Resources Association, Reno, NV, March 14-15, 1995.*

Select Testimony in Litigation and Administrative Hearings

Northeast Natural Energy LLC v. City of Morgantown, Monongalia Circuit Court, Civil Action No. 11-C-411. 2011. Submitted to Deposition. Case dismissed on constitutional grounds.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s 53987-53992, 54003-54021. September 26 through November 14, 2011, Spring Valley, Cave Valley, Dry Lake and Delamar Valley. Testimony on behalf of protestants Great Basin Water Network, Confederated Tribes of the Goshute Reservation.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s 53987-53992, Cave Valley, Dry Lake, and Delamar Valley, NV. February 4 through February 14, 2008. Testimony on behalf of protestant Great Basin Water Network.

Cole et al v. J.M.Huber Corp. and William DeLapp. U.S. District Court for the District of Wyoming. Case No. 06-CV-01421. Written evidence reports and deposition. Case settled.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s, 54003-54021, Spring Valley, NV. Testimony on behalf of protestant Great Basin Water Network. September 11-26, 2006.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s, 54003-54021, Spring Valley, NV. Testimony on behalf of protestant Great Basin Water Network. September 11-26, 2006.

Montana 22nd Judicial District Court, Big Horn County. Diamond Cross Properties, LLC, and Northern Plains Resource Council, and Tongue River Water Users Association v. State of Montana, Pinnacle Gas Resources. Civil Cause No. DV 05-70. Affidavit provided.

Nevada State Engineer, Protest Hearing for Southern Nevada Water Rights Application, #s 72787 – 72797, Tickaboo/Three Lakes Basin. Testimony on behalf of Sierra Club, Indian Springs. November 28 – 30, 2005.

Earlier, several cases before the Nevada State Environmental Commission, on behalf of Great Basin Mine Watch.

CURRICULUM VITAE

MILLER, GLENN C.

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Reno, NV 89557
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email: gcmiller@unr.edu

Born November 17, 1950

Education:

University of California, Santa Barbara, CA	B.S. Chemistry	1972
University of California, Davis, CA	Ph.D. Agricultural Chemistry	1977

Employment:

Univ. of Nevada, Reno	Aug-2009-present	Professor, and Director of the Graduate Program in Environmental Sciences
	2008-2009	On leave for 11 months serving as Manager, Environmental Exposure Assessment, Valent USA Corporation, Walnut Creek CA
	2007-2008, 2010-present	President UNR Nevada Faculty Alliance
	1995-2006	Director, Graduate Program in Environmental Sciences and Health
	1998-2004	Director, Center for Environmental Science and Engineering
	1989-	Professor
	1983-89	Associate Professor
	1979-83	Assistant Professor
	1978-79	Lecturer
Environmental Protection Agency	1977-78	Research Chemist

Professional Societies:

American Chemical Society, Agrochemicals Division and Environmental Division
American Association for the Advancement of Science
Society of Environmental Toxicology and Chemistry
Sigma Xi

Awards:

Thornton Peace Prize (1982)
Junior Faculty Research Award (1982)
UNR Foundation Professor (1991)
Conservationist of the Year, Nevada Wildlife Federation (1995)
College of Agriculture Researcher of the Year (1998)
Friend of the Lake Award, League to Save Lake Tahoe (2001)

Other Professional Activities

Environmental Protection Agency: Competitive Grants Review Panel 1985-1995
Environmental Protection Agency: Advisory Committee on Mining Waste 1991-1993
Environmental Protection Agency: Stakeholder Advisory Committee on Commodity Mercury 2007
Nevada Division of Environmental Protection: Technical Advisory Committee on the Carson River Superfund Site 1991-1994
American Chemical Society, Division of Environmental Chemistry: Chair of the Student Awards Committee 1988-1992
American Chemical Society, Division of Environmental Chemistry: Chair of the Awards Committee 1997-2002
UNR Environmental Studies Board: Chairman 1987-1991
UNR Environmental Science and Health Graduate Program: Director 1995-2006
Consultant to various public interest organizations, companies and law firms
Hydrology/Hydrogeology Graduate Faculty: Member 1989-present
Reviewer for numerous environmental chemistry journals
Co-owner and vice-president: Nevada Environmental Laboratories (Las Vegas and Reno) 1990-1999
Manager, Environmental Exposure Assessment, Valent USA Corporation 8/2008- 8/2009

Courses Taught

Humans and the Environment: Environment 100
Environmental Toxicology: NRES 432/632
Environmental Chemicals: Exposure, Transport and Fate: NRES 433/633
Analysis of Environmental Contaminants: NRES 430/630
Risk Assessment, NRES 793C
Global and Regional Issues in Environmental Science: NRES 467/667

Community and Conservation Service Activities

City of Reno, Charter Review Commission: Chairman 1990-93
Peavine Grade School PTA: Co-President 1990-1992
Sierra Club Mining Committee (national): Co-Chair 1989-1992
League to Save Lake Tahoe Board of Directors: 1986-1999
Mountain and Desert Research Fund: 1987-present
Dupont-Conoco Environmental Leadership Award in Mining Committee: 1989-1994
Nevada Interagency Reclamation Award Committee: 1990-1992
Washoe County School District Science Advisory Board: 1992-2000 Chairman, 1993-94
Earthwords: Board Member 1999-present
Tahoe Baikal Institute: Board Member 1998-present, Chair 2002-2003
Environmental Law Alliance Worldwide Board Member: 2000-present, Chair:2009
Great Basin Mine Watch: Board Member 1994-present, Chair 2001-2006
Center for Science in Public Participation: Board Member 1998-present
Great Basin Institute, Board Member 2000-present, Chair 2001-present
United Nations Environmental Program Committee for Development of a Code for Use of Cyanide in Mining: 2000-2002
Mining, Minerals and Sustainable Development, Assurance Group Committee Member, 2000-2002
National Research Council committee on Methyl Bromide: 1999-2001
National Research Council committee on Mining Technology: 2000-2002

National Research Council committee on USGS Mineral Resources Program, 2000-2003
US Environmental Protection Agency Committee on Management of Mercury Stores in the U.S. 2007

Research Interests: Remediation of mine waste contamination. Mining pit lake water quality. Fate and transport of organic compounds in soils and the atmosphere. Methods of remediation of gasoline contaminated soils; Photochemical transformation of organic contaminants on soil surfaces. Instrumental development of chromatographic systems.

Grants Received: (1982-present)

$ 14,550 "Atmospheric Photolysis of Pesticides," A Junior Faculty Research Award from the UNR Research Advisory Board, 1982.

$ 3,000 "Photolysis of CGA-41065," CIBA GEIGY Corporation, 1982.

$ 4,000 "Chemotaxonomy of Sagebrush Using High Performance Liquid Chromatography," Intermountain Research Station USDA, 1984.

$ 83,000 "Analysis of Bovine Tissue for Chlorinated Hydrocarbons," Environmental Protection Agency, 1984-85.

$ 18,300 "Photooxidation of Sulfide Containing Pesticides on Soil Surfaces," Western Regional Pesticide Impact Assessment Program, 1984.

$ 2,500 "Identification of Sagebrush Taxa Based on Liquid Chromatographic Analyses of Phenolics" Research Advisory Board, 1986.

$235,500 "Factors Affecting the Photolysis of Dioxins on Soil Surfaces," U.S. Environmental Protection Agency, 1986-89.

$ 15,160 "Vapor Phase Photolysis of Phorate," American Cyanamid Corporation, 1987.

$ 2,500 "Identification of Sagebrush Taxa Based on Liquid Chromatographic Analyses of Phenolics," UNR Research Advisory Board, 1987.

$ 48,792 "Upgrading Municipal Wastewater Effluents for Urban Water Reuse through Phytochemical Oxidations: System Development and Operational Criteria," U.S. Geological Survey, State Water Research Institute Program (Co-P.I. with Richard Watts), 1986-88.

$ 17,200 "Vapor Phase Photolysis of Malathion," American Cyanamid, 1988.

$ 16,460 "Aging Groundwater: A comparison of the Fluorocarbon Method to the Tritium Method," U.S. Geological Survey, State Water Research Institute Program (Co-P.I. with K. Sertic), 1988-89. (Competitive Grant, State of Nevada) Terminated 6-89.

$206,000 "In Situ Treatment of Organic Hazardous Wastes in Surface Soils Using Fenton's Reagent." U.S. Environmental Protection Agency (Co-P.I. with Richard Watts), 1988-89. (Competitive Grant, national)

$ 23,200 "Evaporation of Gasoline from Soils," Nevada Division of Environmental Protection Co-P.I. with Susan Donaldson), (Contract).

$ 50,000 "Photolysis of Pesticides on Soils," American Cyanamid Corporation (Unrestricted Grant, noncompetitive)

$ 15,600 "Vapor Phase Photolysis of Diazinon and Methyl Parathion" Western Region Pesticide Impact Assessment Program (USDA) (competitive) 1989-90

$ 30,000 "Interface for a Capillary electrophoresis Effluent and a Mass Spectrometer" Linear Corporation 1989-90. (Co P.I. with Murray Hackett) (contract)

$ 15,000 "UV-Gas Chromatographic Dectector" Linear Corporation 1990. (Co P.I. with Murray Hackett) (Noncompetitive grant)

$153,000 "Enhancement of Photodegradation of Pesticides in Soil by Transport Upward in Evaporating Water" (USGS Competitive) 1991-94

$ 50,000 "Pit Water from Precious Metal Mines" U.S. Environmental Protection Agency, 1992-94

$ 91,000 "Remediation of Acid Mine Drainage at Leviathon Mine" Lahontan Water Quality Control Board. (Contract, Co P.I. with Tom Wildman, Colorado School of Mines) 1992-94.

$159,000 " Ecological Toxicology of Metam Sodium and it Derivatives in the Terrestrial and Riparian Environments of the Sacramento River" California Fish and Game, 1992-1995 (G.C. Miller project, part of a larger project with George Taylor at the Desert Research Institute)

$43,092 “Atmospheric Transport and Deposition of Organophosphates and Other Pesticides as Input to Sierra Nevada Surface Waters” USDA-NRI. 1995-98. Co-P.I. with P.I. James N. Seiber. Task 2.

$80,427 “Linked Techniques for Contaminant Removal from Soil in Arid/Semiarid Environments” Dept. of Energy. 1993-96. Co.P.I with James N. Seiber.

$107,000 “Chemical Environmental Problems Associated with Mining” NIEHS 1993-96. Core B portion. This was a project of a larger Superfund Grant to UNR. James N. Seiber, P.I.

$36,900 “Protocol for Evaluation of Pesticide Photodegradation” Dow-Elanco. 1995-97. (Contract)

$45,000 “Photolysis of Pesticides” Dupont Chemical Company. 1995-98. Unrestricted gift to support ongoing research.

$275,000 “Remediation of Acid Mine Drainage at the Leviathan Mine”. Nevada Division of Environmental Protection. 1996-99

$5000 “Evaluation of Limnology and Water Quality of a Porphyry-Copper Pit Mine Lake” Public Resource Associates 1996.

$767,000 Geochemical, Biological and Economic Impacts of Arsenic and Related Oxyanions on a Mining-Impacted Watershed”   NSF-EPA, 1997-01

$46,000 “Remediation of Acid Mine Drainage at the Leviathan Mine”. Lahontan Regional Water Quality Control Board, 2000-2001

$30,000 "Use of Sulfate-Reducing Bioreactors to Remove Zinc in Mine Drainage" Placer Dome Corporation. 2000-2001

$50,000 “Release of Gasoline Constituents from Marine Engines to Lake Tahoe” Lahontan Regional Water Quality Control Board, 1998-1999

$70,000 "Impact of Marine Engine Exhaust on Pyramid Lake" U.S. Environmental Protection Agency, in cooperation with the Pyramid Lake Paiute Tribe. 2000-2001.

$570,000 "An Environmental Assessment of the Impacts of Polycyclic Aromatic Hydrocarbons in Lake Tahoe and Donner Lake" California Regional Water Quality Control Board, Lahontan Region. 2001-2003.

$126,000 "Operation of a Bioreactor at the Leviathan Mine" Contract with ARCO, 2001-2002

$75,000 Trifluroacetic Acid in Antarctic Ice, National Science Foundation 2001-2004

$190,500 “Mercury Deposition Associated with Mining, U.S. Environmental Protection Agency, 2002-2004

$53,000 Passivation of Acid Generating Rock at the Golden Sunlight Mine, Placer Dome Corporation 2002-2003

$520,000 “Operation of a Bioreactor at the Leviathan Mine" Contract with ARCO, 2003-2007

$250,000 “Risk Assessment and Fate of Polyacrylamide and Acrylamide in Irrigation Canals and Receiving Water” A subcontract from the Desert Research Institute on a project from the U.S. Bureau of Reclamation. 2004-2008

$55,000 Passivation of Acid Generating Rock, Freeport McMoran, 2009-2010

$75,000 Biofuel crops on arid lands, Co-P.I. U.S. Department of Energy, 2010-2011

<u>Publications:</u>

G.C. Miller and D.G. Crosby, "Photodecomposition of Sustar^{R} in Water." J. Agric. Food Chem. 26:1316 (1978).

G.C. Miller and R.G. Zepp, "Effects of Suspended Sediments on Photolysis Rates of Dissolved Pollutants." Water Research 13:453 (1979).

G.C., Miller, M.J. Miille, D.G. Crosby, S. Sontum and R.G. Zepp, "Photosolvolysis of 3,4-Dichloroaniline in Water: Evidence for an Aryl Cation Intermediate." Tetrahedron 35:1797 (1979).

G.C. Miller and R.G. Zepp, "Photoreactivity of Pollutants Sorbed on Suspended Sediment." Environ. Sci. Technol. 13:860 (1979).

G.C. Miller, R. Zisook and R.G. Zepp, "Photolysis of 3,4-Dichloroaniline in Natural Waters." J. Agric. Food Chem. 28:1053 (1980).

G.C. Miller, R.G. Warren, K. Gohre and L. Hanks, "A Gas Chromatographic Method for Determining Strychnine Residues in Alfalfa." J. Assoc. Off. Anal. Chem. 65:901 (1982).

G.C. Miller and W.W. Miller, Eds. "Effect of Sewage on the Truckee River." A symposium published by the University of Nevada, College of Agriculture (1982).

G.C. Miller and R.G. Zepp, "Extrapolating Photolysis Rates from the Laboratory to the Environment." Residue Reviews 85:89 (1983).

G.C. Miller and D.G. Crosby, "Pesticide Photoproducts: Generation and Significance." J. Clin. Toxicol. 19:707 (1983).

G.C. Miller, W.W. Miller, J.W. Warren and L. Hanks, "Soil Sorption and Alfalfa Uptake of Strychnine Applied as an Agricultural Rodenticide." J. Environ. Quality 12:526 (1983).

G.C. Miller and D.G. Crosby, "Photooxidation of 4-Chloroaniline and N-(4-Chlorophenyl)-Benzene-sulfonamide to Nitroso- and Nitro-Products." Chemosphere 12:1217-1227 (1983).

K. Gohre and G.C. Miller, "Singlet Oxygen Generation on Soil Surfaces." J. Agri. and Food Chem. 31:1104-1108 (1983).

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Ralph L. Seiler

PROFESSIONAL EXPERIENCE

Hydrologist

1979-2010 (retired) U.S. Geological Survey Carson City, NV

- Principal investigator for numerous water-quality investigations of surface water and groundwater, including identifying sources of phosphorus in the Carson River, sources of nitrate and bacteria in groundwater, and sources and distribution of TCE in groundwater near a landfill on an Air Force Base in Utah.
- Principal investigator for USGS Fallon leukemia investigation of ground-water quality which involved working closely with CDC, ATSDR, and the State of Nevada. Participated in many public meetings with State and Federal Agencies to explain results of findings related to the presence of arsenic, tungsten, uranium, and polonium-210 in Fallon area groundwater.
- Author of journal articles describing geochemical processes that result in exposure of the public to toxic trace elements and radionuclides.

PUBLICATIONS

Seiler and Wiemels, *in review at Environmental Health Perspectives.* Occurrence of ^{210}Po and biological effects of low-level exposure: The need for research.

Seiler, 2011a, Physical setting and natural sources of exposure to carcinogenic trace elements and radionuclides in Lahontan Valley, Nevada. Chemical-Biological Interactions [Epub ahead of print DOI:10.1016/j.cbi.2011.04.004]

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EDUCATION

Ph.D. Environmental Chemistry

1996-1999 University of Nevada, Reno Reno, NV

B.S./M.S. Biology

1969-1975 University of Utah Salt Lake City, UT

Michele C. Adams, P.E.
LEED AP
Principal Water Resources Engineer

Relevant Experience

Ms. Adams is a Principal Engineer and founder of Meliora Environmental Design. For more than 25 years, her work has encompassed environmentally sensitive site design and sustainable water resources engineering. Building on a multi-disciplinary approach, her work includes both master planning and design for campuses, urban restoration projects, commercial, industrial and residential installations, public facilities, and environmental education centers. In all her work, Ms. Adams seeks to combine sound engineering science with an understanding of natural systems. She is a frequent lecturer and educator on the topics of water and sustainability, and has provided technical expertise to clients ranging from watershed advocacy organizations to corporations. Ms. Adams was one of the principle authors of the Pennsylvania Stormwater Manual, and serves on the U.S. Green Building Council's Technical Advisory Group for Sustainable Sites. She frequently serves as an expert witness with regards to stormwater and water quality issues. Current design projects in which Ms. Adams is engaged include the following:

Stormwater Management for Green and Public Properties, City of Philadelphia: Led a team of engineers, landscape architects, and planners in developing stormwater designs for the City of Philadelphia public properties. The stormwater and landscape designs are intended to reduce impacts to the City's combined sewer system, provide economic cost savings, and promote green infrastructure. Projects have included parks, schools, recreation facilities, and "green streets". A number of projects have been documented through construction and are being (or have been) built.

Purdue University Stormwater Plan: Development of a Stormwater Plan for retrofitting an urban campus to implement an LID approach and incorporate green infrastructure to improve water quality and reduce stormwater runoff volumes. Protection and recharge of drinking water source (groundwater) and water quality protection is a key component of recommendations.

Purdue University Site and Stormwater Improvements at the Mackey Football Fields and Ross-Ade Stadium Parking Lot, West Lafayette, IN: Design of nearly 3 acres of infiltration beds located beneath the Purdue Boilmaker's football practice fields to manage stormwater for the upper campus athletic complex. At the Ross-Ade Stadium, design of bioretention systems to pre-treat runoff from the parking lot and bordering roadways, a drainage area of nearly 6 acres, before the system connects to the infiltration beds under the adjacent football practice fields.

Stroud Water Research Center Environmental Education Center, Academy of Natural Sciences, Avondale, PA: For one of the nation's premier water research and education facilities, provided sustainable site design engineering related to stormwater management including rain gardens, water reuse, and green roof.

U.S. Botanic Garden Bartholdi Park, Washington, D.C.: Designing stormwater management measures in the landscape to serve as demonstration sites as well as to demonstrate compliance with the new Federal Regulations for stormwater management as part of Section 438 of the Energy Independence and Security Act. The project is also seeking certification from the Sustainable Sites Initiative.

High Performance Landscapes, New York City Parks and Recreation: Ms. Adams served as one of four authors in development of the New York City's *High Performance Landscapes* document, specifically addressing water issues. This publication will be the third in the series that began with *High Performance Buildings*.

Special Qualifications

Twenty-five years of experience in civil and water resources engineering.

Sustainable site design engineering, including Stormwater Best Management Practices, Low Impact Development, (porous pavement, bioretention, tree trenches, vegetated roofs, etc) and alternative wastewater treatment systems (wetlands, drip irrigation, recirculating filters). Design for projects seeking LEED certification.

Watershed studies, computer modeling, stormwater sampling, stream flow monitoring, NPDES permit applications, mixing zone analyses, pollution prevention plans.

Professional Credentials

Bachelor of Science Civil Engineering
Pennsylvania State University, State College, PA, 1984

Graduate Coursework Water Resource Engineering
Villanova University, PA
1997-2001

Registered Professional Engineer in Delaware, Pennsylvania, Virginia, Maryland

LEED Accredited Professional

Waterview Recreation Center, City of Philadelphia and Pennsylvania Horticultural Society: For an existing urban recreation center, design of "green infrastructure" stormwater elements to improve community amenities and reduce combined sewer overflows. Elements include stormwater tree trenches, stormwater planter boxes, and a cistern for the community garden. *This project has recently been the subject of a GreenTreks video on stormwater.*

Greenstreets Design, East Falls: Led a team of design professionals (traffic engineers, landscape architects, pedestrian designers, stormwater engineers) in the design of a "complete" street for an urban neighborhood, including two design charettes with regulatory and design professionals from various city and state agencies. The goal was to develop a complete street that addressed stormwater, various transportation modes, and neighborhood greening and revitalization.

University of Pennsylvania Shoemaker Green, Philadelphia: Design of a passive open space on Penn's Campus that captures runoff generated by new and existing impervious surfaces into site and landscape features throughout the site. The project is also seeking certification from the Sustainable Sites Initiative.

Three Groves Ecovillage: Evaluating the Zoning Overlay for the proposed Ecovillage as well as designing the Water system, Wastewater Collection system, and stormwater measures for the site. Consisting of small residential buildings, community greenhouses, community buildings, natural pools, a constructed wetland treatment system, and bioswales, the proposed Ecovillage development is a model sustainable "green" neighborhood.

Philadelphia Zoo Master Plan: Development of water and environmental recommendations for the Zoo Master Plan, with focus on stormwater measures integrated into the Zoo's landscape to address flooding problems while promoting sustainability.

Greening and Stormwater Retrofits for Urban Schoolyards, Philadelphia: For two existing urbanized school yards (Greenfield School and Independence Charter School) that previously consisted only of asphalt, designed elements intended to both capture the first inch of runoff and provide greening, environmental education, and reduce heat island effects. Components include rain gardens, porous asphalt, porous pavers, and vegetated swales. *Greenfield School has recently been the subject of a GreenTreks video on stormwater.*

Stormwater Plans and Environmental Site Design Analysis for Maryland Projects: For the Chesapeake Bay Foundation and Audubon Society, Ms. Adams led an effort to evaluate various project sites in Maryland and provide recommendations and cost estimates for implementing landscape and stormwater measures to achieve the goals of Maryland's ESD process.

Okehocking Nature Center, Willistown Township, PA: Sustainable site design engineering for new Environmental Education Center, including stormwater management and wastewater treatment systems that are integrated with the natural landscape restoration.

Levin Tract Wooded Wetland Park, Radnor, PA: For the urbanized Radnor, PA area, developed a restoration concept design to convert an abandoned vacant parcel into a wooded wetland park area that will improve water quality from a 40-acre urban drainage area by creating a series of low, wooded wetland depressions and planting areas.

Professional Employment History

2007- Present
Principal Engineer and Founder
Meliora Environmental Design
Kimberton, PA

1997- 2007
Principal Engineer
Cahill Associates, West Chester, PA

1991-1997
Project Manager
Roy F. Weston, Inc., West Chester, PA

1984-1991
Project Engineer
Cahill Associates, West Chester, PA

Professional Memberships

U.S. Green Building Council – Sustainable Sites Technical Advisory Committee (SS TAG)

Member, American Society of Civil Engineers, Environmental Water Resources Institute

Member, Pennsylvania Association of Environmental Professionals

Member, American Water Resources Association

Visiting Guest Lecturer; University of Pennsylvania Schools of Architecture and Landscape Architecture; Philadelphia University, and Temple University

East Vincent Planning Commission Chairman

Ralston House, University of Pennsylvania: Design of stormwater elements to support an urban landscape restoration at an existing healthcare facility for the elderly.

Tyler Arboretum Path System: Designed a system of porous asphalt paths through an existing arboretum to improve access and address localized erosion problems.

Hershey Gardens Stormwater Plan: Developed program of rain gardens, wetlands, and restoration measures to address existing erosion and flooding problems.

North 3rd Street Corridor Sustainable Affordable Housing Plan, Philadelphia: With SMP Architects, designing guidelines for sustainable affordable housing, including stormwater measures to reduce combined sewer overflows and meet new City of Philadelphia ordinances.

Hamilton Children's Zoo at the Philadelphia Zoo: Design of site elements, including stormwater elements that provide educational opportunities, such as wetlands, green roofs, porous paths, and cisterns.

Oxford Library: Sustainable site design and engineering for a library addition to an urban library that includes porous pavers, rain gardens, and public outdoor gathering spaces to promote environmental education.

Mount Saint Joseph Academy Stormwater Improvements: With the Pennsylvania Horticultural Society, design of landscape-based restoration measures to improve stormwater management and educational opportunities at an existing school.

Chanticleer Garden: Stream daylighting of buried tributary and floodplain restoration.

Fire Engine 38: Site design of a new Fire Station in Philadelphia to include green roof, bioretention, and landscape restoration. Project will be LEED certified.

John Hopkins Sustainability House: Site design of a building at John Hopkins to create a Sustainability House and define sustainability criteria for University.

Stroud Model My Watershed: Providing technical expertise in the development of an educational watershed modeling tool being developed through funding from the National Science Foundation. Tool will allow interactive evaluation of development impacts on water balance and water quality, and allow alternative designs to be evaluated for benefits of groundwater restoration, stream health, and water quality.

Panther Hollow Watershed Restoration: Developing a watershed restoration plan which includes hydrologic modeling of the natural and existing conditions, using WinSLAMM, and design of two pilot projects to include elements such as an infiltration trench to capture adjacent street runoff, and retentive grading/infiltration berms to manage compacted lawn on a golf course.

For ten years prior to forming Meliora (1997 – 2007), Ms. Adams was a Principal Engineer with Cahill Associates, where she successfully directed and participated in all aspects of a number of projects.

Pennsylvania Stormwater Best Management Practices Manual, Pennsylvania DEP, co-author of State Manual describing structural and non-structural BMPs, Control Guidelines, calculation methodologies, and specifications, including a volume-based approach to stormwater.

Environmental and Stormwater Master Plan, UNC Chapel Hill, NC, Environmental master planning for sustainable stormwater approach to address large university expansion plan. Detailed hydrologic computer modeling performed in US EPA SWMM to evaluate existing infrastructure and recommend stormwater measures. Represented new LID approach in stormwater for UNC and was recognized by Sierra Club as a "Top Ten Building Better II" project.

Grey Towers National Monument, National Forest Service, Sustainable site design, including various stormwater measures for historic gardens, porous pavement, water and wastewater systems.

Washington National Cathedral, D.C., Restorative stormwater measures for Cathedral site and woods, including various infiltration measures (at source of runoff), infiltration for road system, channel stabilization, etc. Second phase included infiltration trenches integrated in to new outdoor amphitheater.

Mill Creek Community Garden and Clark Park Urban Stormwater Projects, Philadelphia, PA, Design of urban stormwater systems that collect runoff from City streets and infiltrate/manage water in urban green spaces such as community gardens and new basketball courts.

Cusano Center at John Heinz National Wildlife Refuge, Tinicum, PA, Sustainable site design for educational center, including various stormwater elements.

Springbrook Low Impact Development, Lebonon County, PA, Design of full LID stormwater system for 247 residential units in karst area, including over 120 individual stormwater systems (vegetated infiltration beds, infiltration trenches, rain gardens, porous pavements, etc.).

Bartrams Garden Master Plan, Philadelphia, PA, Restorative stormwater management recommendations for Master Plan of historic garden.

Regent Square Gateway, Nine Mile Run, Pittsburgh, PA, Concept and schematic design for urban stream and park "gateway".

Ford Rouge Stormwater Management, Dearborn, MI, Stormwater planning and design for major industrial facility re-development (Porous pavement, bioretention swales, vegetated systems).

Woodlawn Library, Wilmington, DE, Design of urban stormwater measures at new public library to reduce stormwater in combined sewers. Porous parking, bioretention, cisterns with re-use, stormwater planter boxes.

From 1991 through 1997, Ms. Adams was a Project Engineer and Project Manager at Weston.
Stormwater Management Programs and NPDES permitting Between 1992 and 1996, Ms. Adams developed and implemented stormwater management and sampling programs at over fifty industrial, commercial, and military facilities throughout the United States, including the Bureau of Engraving and Printing, Philadelphia International Airport, and various industrial facilities. These programs focused on reducing stormwater and water quality impacts from existing facilities.

Hydrologic, Hydraulic, and Mixing-Zone Modeling For a variety of watershed studies including Act 167 Plans, Ms. Adams conducted hydrologic and hydraulic modeling using various mathematical computer models, including USDA TR-20, EPA SWMM, and COE HEC models. Ms. Adams also performed floodway

Expert Testimony within Past Three Years

2010	**Blue Mountain Preservation Association vs Alpine Development Rose Resorts;** Pennsylvania Environmental Hearing Board. Expert witness on behalf of BMPA on issues related to stormwater management and water quality.
2010	**Koziell and Perrini vs Madison Township; Lackawanna Court of Common Pleas;** Expert witness on adverse stormwater impacts of road improvements.
June 2010	**West Vincent Zoning Hearing Board; Flather Property;** Testimony on behalf of Green Valleys Association and PennFuture related to impacts of **water** quality on variance request for stream buffer and wetland setback requirements.
Jan 2010	**West Pikeland Zoning Hearing Board;** Testimony on behalf of Green Valley Association related to impacts of water quality and stream health on variance requests to environmental ordinances.
2009/2010	**Tim and Jamie Lake vs The Hankin Group;** Court of Common Pleas Chester County; Expert witness on stormwater design and flooding.
2008-2009	**Crum Creek Neighbors vs DEP, et al;** Pennsylvania Environmental hearing Board; Expert witness on stormwater design review and impacts on flooding and water quality.
2007-2008	**Glenhardie Condominium vs. Realen Associates; Appeal of NPDES Post-construction Stormwater Management Permit;** Expert witness on behalf of Glenhardie related to stormwater design and flooding. Permit was withdrawn.

Expert Analysis and Comment within Past Three Years

2009/2010	**Pennsylvania Turnpike Expansion Project;** on behalf on National Park Service Valley Forge National Park and Valley Creek Coalition. Expert services related to review and comment of stormwater design and impacts on water quality and stream conditions.
2009/2010	**City of Philadelphia Longterm Control Plan;** on behalf of Natural Resources Defense Council and PennFuture; review of technical reports, policy documents, and draft permit conditions on issues related to stormwater management, water quality, stream health, and compliance with Clean Water Act and EPA Longtern Control Policy.
2010	**City of Chattanooga MS4 Permit**: For City of Chattanooga, providing technical guidance for incorporation of stormwater measures to address and restore impaired streams and meet TMDL requirements. Training sessions for municipal officials and program development.

Publications

Design for Flooding: Architecture, Landscape, and Urban Design for Resilience to Climate Change; By Donald Watson and Michele Adams; Wiley Publishing, Hardcover Nov 2010.

Park Design for the 21st Century: High Performance Landscape Guidelines; New York City Parks Department and NYC Design Trust; Nov 2010.

Porous Asphalt Pavement: 20 Years and Still Working, Michele Adams, Published in Stormwater Magazine May/Jun 2003

Presentations and Conference Proceedings

2010

Nov Greenbuild USGBC National Conference; New Directions in Stormwater Management and LEED
Nov AWRA National Conference; New Direction in Water Management
Oct Delaware Valley Green Building Council; New Directions in Stormwater Management in Philadelphia
Sep Pittsburgh Parks Conservancy; Michele Adams; "What's Going on in Panther Hollow" and examples of innovative engineering solutions to stormwater impacts on the watershed; Pittsburgh, PA
May "Sustainable Stormwater Management for Municipal Officials"; Lecture series for municipal officials sponsored by Brandywine Valley Association
Apr "Stormwater Management in Pennsylvania", Environmental Law Forum, Harrisburg, PA
Apr "Rainwater Management", Institute for Conservation Leadership
Mar "How to Challenge a Stormwater Permit and Win: A Look at the Crum Creek Neighbors Decision" Michele Adams, James Schmid, and John Wilmer; Schuylkill Watershed Congress; Pottstown, PA

2009

Dec "Bio-retention, Vegetative roofs, rain gardens, stormwater management" sponsored by East Nantmeal Township Environmental Council
Oct "Regenerative Urban Stormwater: Example Projects in the Philadelphia Region" Michele Adams and Susan McDaniels Pennsylvania Stormwater Conference; Villanova, PA
Oct Housing and Water: Syncing Neighborhood Development, Stormwater Management, and Water; AIA Design on the Delaware
Oct "Sustainability and Stormwater Management: Green Infrastructure" American Planning Association National Conference
Sept LID and Stormwater; 16th Annual Erosion Control Conference
May "Green Infrastructure and Urban Revitalization" Greening the Heartland Conference, Detroit, MI
May "Protecting Our Natural Resources: Design Leadership for the Next 100 Years" AIA National Conference, San Francisco.
May "Putting It Into Practice: Low Impact Development And Stormwater Management Training" Pennsylvania Land Conservation Conference
May "Reconnecting Water, Soils, and Vegetation: Stormwater Management in the Built Environment" ASLA PA/DE Annual Meeting.
Mar "Water, Soils, and Vegetation: Sustainable Site Design" Purdue University Sustainability Conference
Mar "Promoting LID Redevelopment in the Anacostia Watershed" Washington, DC

2008

Jan AIA/DVGBC, Philadelphia; Porous Pavement: How, Why, and When
Mar DVGBC Best of GreenBuild

2007

Nov USGBC GreenBuild, Chicago; Michele Adams; UNC Chapel Hill: A Campus-wide approach for Growth and Sustainability

Aug "Urban Stormwater and LEED"; Michele Adams, Energy Coordinating Agency of Phila; Demystifying LEED for Homes Event.

May "Low Impact Development: What's Important and What Should be Monitored"; Michele Adams and Wesley Horner; Tampa; 9th Conference on Stormwater Research & Watershed Management; Fla DEP

May "Low Impact Development"; Wesley Horner and Michele Adams; ASCE EWRI World Environmental &Water Resources Congress; Conference; Orlando, Fla

April "Integrating Sustainable Stormwater into the Campus"; Michele Adams and Thomas Cahill; Baltimore, MD; Smart and Sustainable Campuses Conference, EPA/Society for College and University Planning.

April; "Stormwater Management at UNC Chapel Hill: A Plan for Growth and Sustainability"; Jill Coleman, UNC, and Michele Adams; Wilmington, NC, 2nd National Low Impact Development Conference

April "Using the BMP Manual to Meet NPDES Requirements"; Michele Adams; State College, PA; Chesapeake Bay Foundation Confluence 2007, Connecting Communities to Creeks.

March "Porous Pavements"; Michele Adams, Public information session hosted by the City of Wichita

2006

Nov "Urban Stormwater BMPs: Finding Space for Stormwater in the Urban Environment", Michele Adams; Baltimore, MD; AWRA 2006 Annual Water Resources Conference

Nov "Sustainable Site Design"; Michele Adams; Philadelphia, PA; Design on The Delaware AIA Regional Conference

Sept "Stormwater Site Design: porous Asphalt and Other Innovative Stormwater Techniques"; Michele Adams; Kansas City, MI; American Public Works International Congress and Exposition

Sept "Sustainable Stormwater Management"; Michele Adams; Pittsburgh, PA; 3 Rivers Wet Weather 8th Annual Sewer Conference

Sept "Regent Square Gateway Vision for Nine Mile Run"; Marijke Hecht and Michele Adams; University of Pittsburgh, PA

Sept "The Etowah Habitat Conservation Plan and Runoff Limits"; Michele Adams; Atlanta, GA; Public workshops sponsored by Etowah Watershed Organization and the River Basin Center Institute of Ecology University of Georgia.

June Blair County LID Workshop; Michele Adams; Hollidaysburg, PA;

June Penn State Visitor Center LID Design; Michele Adams; State Colege, PA; Penn State Computational Methods in Stormwater Management

May "Rams Head Extensive Green Roof Design at UNC Chapel Hill"; Andrew Potts and Michele Adams; Boston, MA; Green Roofs for Healthy Cities Conference

May Penn State Visitor Center LID Demonstration Tour; Michele Adams; Pennsylvania Association of Environmental Professionals.

Mar "Porous Asphalt Pavement: The Right Choice"; Michele Adams; Orlando, FLA; NAPA World of Asphalt

Jan "Sustainable Stormwater Management"; Michele Adams; Atlantic City, NJ; NJ ASLA Annual Meeting

Various Dates and Locations in PA: Stormwater Management Workshops for Municipal Officials and Engineers; Sponsored by the Pennsylvania Environmental Council

2005

Dec "Sustainable Design in Our Communities"; Michele Adams and Tavis Dockwiller; Sturbridge, MA; presented by Green Valleys Institute

Nov "Designing Bio/Infiltration Best Management Practices for Stormwater Quality Improvement"; Michele Adams; Madison, WI; University of Wisconsin Professional Development Course

Oct "Springbrook: Residential LID in a Limestone Area; Andrew Potts and Michele Adams; Villanova, PA; 2005 Pennsylvania Stormwater Management Symposium

July "Sustainable Site Design"; Michele Adams; Trenton, NJ; AIA NJ Tectonics of Sustainable Design

June Penn State Visitor Center LID Design; Michele Adams; State Colege, PA; Penn State Computational Methods in Stormwater Management

April "Urban Stormwater BMPs: Finding Space for Stormwater in the Urban Environment*";* Wesley Horner and Michele Adams; Tampa, FLA; 8th Biennial Conf on Stormwater Research & Management.

Mar "Sustainable Site Design"; Michele Adams and Tavis Dockwiller; sponsored by Fulton County, PA

Ruth Ayn Sitler, P.E.
Water Resources Engineer

Meliora Environmental Design, LLC

Relevant Experience

Ms. Sitler is a Water Resources Engineer at Meliora Environmental Design with over seven years of civil engineering experience that includes low impact development and sustainable stormwater management design. To date, her experience has provided her with a vast multi-disciplinary background from which to draw for innovative design projects of all scopes and sizes, and includes commercial and residential construction, educational facility construction, stream restoration projects, abandoned mine reclamation, and pavement management and design. Ms. Sitler also has experience in environmental permitting as well as local government operations.

Current designs in which Ms. Sitler has been engaged include the following:

Greenstreets Design, East Falls: Part of a team of design professionals (traffic engineers, landscape architects, pedestrian designers, stormwater engineers) in the design of a "complete" street for an urban neighborhood, including two design charettes with regulatory and design professionals from various city and state agencies. The goal was to develop a complete street that addressed stormwater, various transportation modes, and neighborhood greening and revitalization.

Three Groves Ecovillage: Evaluating the Zoning Overlay for the proposed Ecovillage as well as designing the Water system, Wastewater Collection system, and stormwater measures for the site. Consisting of small residential buildings, community greenhouses, community buildings, natural pools, a constructed wetland treatment system, and bioswales, the proposed Ecovillage development is a model sustainable "green" neighborhood.

Panther Hollow Watershed Restoration: Developing a watershed restoration plan which includes hydrologic modeling of the natural and existing conditions, using WinSLAMM, and design of two pilot projects to include elements such as an infiltration trench to capture adjacent street runoff, and retentive grading/infiltration berms to manage compacted lawn on a golf course.

Philadelphia Zoo Master Plan: Development of water and environmental recommendations for the Zoo Master Plan, with focus on stormwater measures integrated into the Zoo's landscape to address flooding problems while promoting sustainability.

Special Qualifications

Seven years of experience in civil and water resources engineering.

Sustainable civil/site design engineering, including Stormwater Best Management Practices, Low Impact Development, (porous pavement, bioretention, etc).

Integrated water resource planning; regional watershed planning; computer modeling; environmental , transportation, and construction permitting; local ordinance development and implementation.

Professional Credentials

Post-Graduate Coursework
Coastal Engineering
Old Dominion University, VA
2012-present

Master of Engineering
Environmental Engineering
Pennsylvania State University, PA, 2007

Bachelor of Science
Civil Engineering Technology
Pennsylvania College of Technology, PA 2004

Registered Professional Engineer in Pennsylvania

Certified Surveyor-in-Training in Pennsylvania

Professional Employment History

2011- Present
Water Resources Engineer
Meliora Environmental Design
Phoenixville, PA

Expert Testimony within Past Three Years

Jan 2012 **London Grove Zoning Hearing Board;** Testimony on behalf of Three Groves Ecovillage Development, L.P., related to site design engineering components and conformance to local ordinance standards for conditional use approval.

2010 **Butler County Act 167 Stormwater Management Plan Public Hearing;** Testimony on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Butler County Act 167 Stormwater Management Plan.

2010 **Crawford County Act 167 Stormwater Management Plan Public Hearing;** Expert witness on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Crawford County Act 167 Stormwater Management Plan.

2010 **Mifflin County Act 167 Stormwater Management Plan Public Hearing;** Testimony on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Mifflin County Act 167 Stormwater Management Plan.

2010 **Montour County Act 167 Stormwater Management Plan Public Hearing;** Testimony on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Montour County Act 167 Stormwater Management Plan.

2010 **Potter County Act 167 Stormwater Management Plan Public Hearing;** Expert witness on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Potter County Act 167 Stormwater Management Plan.

2010 **Venango County Act 167 Stormwater Management Plan Public Hearing;** Expert witness on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Venango County Act 167 Stormwater Management Plan.

2010 **Warren County Act 167 Stormwater Management Plan Public Hearing;** Testimony on behalf of the Pennsylvania Department of Environmental Protection related to the adoption and implementation of the Warren County Act 167 Stormwater Management Plan.

2008-2011
Civil Engineer Manager and Sr. Civil Engineer
Comm. of Pennsylvania:
PA Dept. of Env. Prot.
(Bur. of Aban. Mine Rec.)
(Bur. of Watershed Mgmt.)
PA Dept. of Transportation
(Bur. of Maint. And Oper.)
Harrisburg, PA

2006-2007
Project Manager
Navarro & Wright Consulting Engineers, Inc.
New Cumberland, PA

2006-2006
Project Designer
Raudenbush Engineer, Inc.
Middletown, PA

2005-2005
Project Designer
Morris & Ritchie Associates
York, PA

2004-2005
Transportation Engineer I
Buchart-Horn, Inc.
York, PA

Professional Memberships

Member, American Society of Civil Engineers, Environmental Water Resources Institute

Expert Analysis and Comment within Past Three Years

2011 **AML-1: The Abandoned Mine Land Inventory Manual;** on behalf of the Pennsylvania Department of Environmental Protection, Bureau of Abandoned Mine Reclamation; Technical review and comment of revisions to the Department of interior, Office of Surface Mining's regulatory standards for addressing abandoned mine lands.

2011 **Alternate Pavement Type Bidding**: on behalf of the Pennsylvania Department of Transportation, Bureau of Maintenance and Operations; Expert analysis of alternate pavement type bidding policies as implemented on highway design projects in Pennsylvania.

Publications

Streambank Stability: Modeling Channel Evolution and Pollutant Transport in an Urban Stream; Ruth A. SItler; Pennsylvania State University, Masters Paper; Dec 2010.

Geographic Variability of Rainfall Erosivity Estimation and Impact on Construction Site Erosion Control Design; Shirley E. Clark, Aigul Allison, and Ruth A. Sitler; *Journal of Irrigation and Drainage Engineering*; American Society of Civil Engineers; July 2009.

Special Experimental Project No. 14 (SEP-14) Alternate Pavement Type Bidding Initial Report; Pennsylvania Department of Transportation and the Federal Highway Administration; Feb 2011.

Porous Asphalt Pavement: 20 Years and Still Working, Michele Adams, Published in Stormwater Magazine May/Jun 2003

Presentations and Conference Proceedings

2011

Sep Low impact Development Symposium; Ruth A. Sitler; "Impact of the Rainfall Event Method on the Water Capture Quantity Efficieny of Bioretention Devices"
May 2011 World Environment & Water Resources Congress; Ruth A. Sitler and Shirley E. Clark; "Impact of Bioretention Design of the Calculation Method for the 95th Percentile Rain Event"

2009

Mar "Act 167 Stormwater Management;" Harrison City, PA
May 2009 World Environment & Water Resources Congress; Christine Y. Siu, Shirley E. Clark, Ruth A. Sitler and Katherine Baker; "Looking Upstream and Into the Watershed for the Big Picture of Stream Health"
June "Act 167 Stormwater Management – Municipal Implementation Models;" Mercer, PA
July "Introduction to Hydrologic Modeling with HEC-HMS;" Harrisburg, PA
"Building a Project and Running a Simulation with HEC-RAS;" Harrisburg, PA
Oct 2009 Pennsylvania Stormwater Management Symposium; Ruth A. Sitler, Aigul Allison, and Shirley E. Clark; "Geographic Variability of Rainfall Erosivity Estimation and Impact on Construction Site Erosion Control Design"

2008

Feb	“Small Watershed Hydrology Modeling with WinTR-55;” Middletown, PA
	“AutoCAD;” Middletown, PA
Mar	“Erosion Control and NPDES Permitting;” Middletown, PA
Apr	“Introduction to HEC-RAS;” Middletown, PA
	“HEC-HMS: The Hydrologic Engineering Center’s Hydrologic Modeling System;” Middletown, PA
May	“Planning to Protect Water Resources: Stormwater Management;” Hershey, PA
Sep	“Understanding the Regulatory Environment: DEP Headwaters Initiatives and Stormwater BMPs;” Monroeville, PA
Oct	“Integrated Water Resource Planning through Act 167;” Harrisburg, PA
Nov	“Stormwater Management: Act 167 and Its Implementation;” Harrisburg, PA

2007

Mar	“Engineering Overview of Erosion Control and NPDES Permitting in Central Pennsylvania;” New Cumberland, PA
Oct	2007 Pennsylvania Stormwater Management Symposium; Ruth A. Sitler and Shirley E. Clark; “Streambank Stability: Modeling Channel Evolution and Pollutant Transport in an Urban Stream”

NIEK VERAART, AICP, ASLA **Project Manager**

Mr. Veraart is vice president with LBG with more than 20 years of diverse experience in environmental planning, including EIS in accordance with NEPA, SEQRA and CEQR and other environmental statutes. His environmental planning assignments have encompassed a wide range of projects, including transportation infrastructure (airports, highways, ports, rail/transit) industrial facilities (solid waste management, energy, water and wastewater facilities), large-scale development projects (residential, commercial, mixed use, recreational and transit-oriented development), ecological and sustainable development (watershed management, LEED compliance, waterfront restoration, wetland banking) and cultural resources (memorials, tourist attractions, national parks). He is familiar with regulatory requirements at federal, state, and local levels and has integrated such requirements on multilevel environmental documents, including such high-profile assignments as the World Trade Center Memorial and Redevelopment GEIS. Mr. Veraart is especially familiar with construction impacts and assisted federal and state agencies with the development of Environmental performance Commitments (EPCs) for the rebuilding of Lower Manhattan. Mr. Veraart is familiar with upstate watershed issues through his completion of several SEQRA assignments, including an EIS for the Hackensack River in Clarkstown, New York; infrastructure improvements for the Bear Mountain Bridge (for NYSDOS); and the EIS for Kensico Watershed Water Pollution Control Program (for NYCDEP). Mr. Veraart's experience with third-party EIS review is extensive and includes multiple EISs for US Army Corps of Engineers, EIS review for local public interest environmental organizations and for the New York State Public Service Commission.

Several of the projects led by Mr. Veraart have received prestigious state and national awards. Mr. Veraart has presented at national conferences on subjects of environmental planning and his research contributions in the transportation and environmental planning fields have been published by the National Academy of Sciences, Transportation Research Board.

FIRM Louis Berger Group

EDUCATION

- MS, Regional Planning and Land Planning
- BS, Land Planning and Landscape Architecture

REGISTRATIONS / CERTIFICATIONS

- American Institute of Certified Planners
- American Society of Landscape Architects
- American Society of Civil Engineers, Affil.
- International Association for Impact Assessment

YEARS EXPERIENCE 24
YEARS WITH FIRM 16

RELEVANT PROJECT EXPERIENCE

Lower Manhattan Development Corporation (LDMC), GEIS for World Trade Center Memorial and Redevelopment Plan (SEQRA, NEPA EIS), New York, New York. Project director. Mr. Veraart directed LBG's work for the WTC GEIS, which was co-prepared by LBG with another consulting firm. Under Mr. Veraart's direction, transportation analyses were conducted for the redevelopment of the World Trade Center site and construction scenarios were developed for input into the Traffic, Air Quality and Noise analyses. The GEIS process for this high-profile; complex project was completed within a record time of 12 months from the start of environmental review. Mr. Veraart also directed noise, infrastructure, utilities as well as issues of cumulative impacts.

US Army Corps of Engineers New York District, Third-Party EIS, Meadowlands Mills Regional Mall, Bergen County, New Jersey. Project director. Mr. Veraart was Task manager for the independent third-party review of the developer's EIS and preparation of a federal FEIS and Section 404(b) Permit Alternatives Analysis for the development of a 600-acre site for the construction of a mixed use regional mall, office and recreation complex, located three miles from New York City. The project would involve the filling of approximately 200-acres of wetlands and extensive wetland creation and enhancement.

US Army Corps of Engineers New York District, Meadowlands Comprehensive Restoration Implementation Plan Programmatic Environmental Impact Statement, New Jersey. Provided QA/OC review of the Programmatic Environmental Impact Statement (PEIS) for the Meadowlands Comprehensive Restoration Implementation Plan (MCRIP). The PEIS provides an evaluation of environmental, social and economic issues and alternatives to achieve project goals and objectives, while avoiding/minimizing adverse impacts, providing the USACE with the necessary NEPA compliance documentation for MCRIP implementation. The PEIS is a comprehensive document that considers a number of related actions proposed in the MCRIP, including cumulative, direct, and indirect impacts.

New York City Department of Environmental Protection, Kensico Watershed Water Quality Sustainable Management Plan EIS, Westchester County, New York. Project manager. The EIS evaluated the beneficial effects on water quality resulting from several alternative measures, including the development of stormwater Best Management Practices (BMPs), such as wetland basins, streambank stabilization and waterfowl management. Pollutant reductions were subsequently modeled for each of the streams and subwatershed discharging into the Kensico Reservoir. Transport of contributing pollutants within the reservoir and to the water intakes was then modeled. In addition to the evaluation of the effectiveness of various program alternatives, their impact on the environment was assessed, including socioeconomic and ecological impacts.

Metropolitan Transportation Authority New York City Transit, Fulton Street Transit Center NEPA EIS, New York, New York. Project director. Directed the preparation of the FEIS and Section 4(f) for the $1.4B federally funded Fulton Street Transit Center (FSTC) in Lower Manhattan. Mr. Veraart supervised the approach to alternatives analysis and cumulative effects analysis and supervised preparation of technical assessment of environmental impacts, including traffic and transportation, air, noise, socio-economic analyses and the analysis of adaptive reuse of the historic Corbin Building in Lower Manhattan. A key aspect of the analysis was the assessment of cumulative impacts of the FSTC and other Lower Manhattan Recovery Projects. Mr. Veraart presented the analysis of cumulative construction in Lower Manhattan to a National Panel of government agencies under auspices of the FTA.

US Department of Agriculture, Final Environmental Impact Statement (FEIS - SEQRA, NEPA) Gull Hazard Reduction Program, JFK International Airport, Jamaica, New York. Project manager. Managed the preparation of the SEQRA/NEPA EIS for the implementation of the Gull Hazard Reduction Program at JFK International Airport in New York City.

Parcel B EIS Third-Party Review and Environmental Support Services, Purchase Environmental Protection Association, Purchase, New York. Project manager. Analyzed SEQRA documentation submitted for an office development in Purchase, New York. The expert review team lead by Mr. Veraart reviewed all relevant aspects of the analyzed by the developer and identified numerous deficiencies and inaccuracies in the environmental documentation, including historic resources (impacts on Olmstead landscapes and resources listed on the State/National Register of Historic Places), flooding and stormwater management, incompatibility with zoning regulations, density inconsistencies, traffic safety and congestion issues, ecological impacts and direct and indirect wetland impacts.

Dormitory Authority of the State of New York (DASNY), Chenango Countywide 911 Communications Upgrade EIS, Chenango County, New York. Project Director. Led the preparation of the SEQRA EIS. The project included a GIS-based viewshed analysis of tower visibility. The viewshed analysis included the identification of sensitive resources (e.g. parks and historic areas) within five miles of each tower. The project objective was to improve emergency services communication capabilities through the construction of six radio communication antenna towers and ancillary infrastructure, and upgrades to facilities at an additional three sites

US Army Corps of Engineers New England District, South Coast Rail Project Third-party NEPA EIS (in progress), Massachusetts. Project manager. Mr. Veraart is managing the preparation of an Alternatives Analysis and NEPA EIS for new 60-mile transit service between Boston and the south coast of Massachusetts, including New Bedford and Fall River. Alternatives being evaluated include Bus Rapid Transit and rail. Key impact areas addressed included wetlands, water resources, threatened and endangered species, noise and vibration and coordination with Native American tribes.

Township of Randolph, Third-Party Environmental Review and Site Suitability Analysis Services, Randolph, New Jersey. Project manager. Conducted an independent third-party review of the environmental documentation for the 154-acre Nitti Mountain development project in the Township of Randolph, New Jersey. The review assessed all applicable resources including soils, geology, wetlands, hydrology, slopes/engineering, ecology; land use and zoning, landscape and visual, traffic/circulation and access, cultural resources and socioeconomic impacts. The report provided comments and recommendations regarding technical methodologies, data gaps and data quality, compliance with applicable regulations and appropriateness, projected cost and feasibility of proposed mitigation measures.

City of New City, New York, FEIS, Hackensack River Natural Area Improvement and Flood Management Project, Clarkstown, New York. Project director. Mr. Veraart directed the preparation of the FEIS for flood control measures in the Hackensack River. Flood control measures include the construction of backwater prevention berms, dredging of river sediment and widening of the river in order to improve flow.

NYS Bridge Authority, EA (SEQR) Bear Mountain Bridge Rehabilitation, Bear Mountain,

New York. Project director. Directed environmental permitting and regulatory issues for rehabilitation of the Bear Mountain Bridge across the Hudson River.

Port Authority of New York and New Jersey, Newark Liberty International Airport, Terminal A NEPA Draft Environmental Assessment. Newark. New Jersey. Project manager. Preliminary Environmental Assessment for construction of a new Terminal A facility, including a 1.3 million sf. airport terminal building, surrounding site conditions, including streams and wetlands, roadways and airside facilities. The EA was prepared in close coordination with sustainable planning and design efforts ongoing concurrently towards a LEED certified facility.

LMDC and the National September 11 Memorial & Museum, Pedestrian Simulation Modeling - World Trade Center (WTC) Memorial, New York, New York. Project director. Oversaw the development of origin/destination projections for pedestrian travel patterns on the World Trade Center (WTC) Memorial including the plaza, visitor's center, and museum and the entire WTC Site for the opening year and stabilized year of the WTC Memorial on both a weekday and Saturday. Also developed assumptions for the development program, pedestrian profiles, pedestrian itineraries, and site demand projections. The projected pedestrian movements were modeled to determine if adequate space would be provided for pedestrians based upon the site design and site plan

State University of New York at Binghamton. New Student Housing, State. Town of Vestal, Broome County, New York. Project Director. Directed the preparation of a SEQRA EAF and Supplemental Studies for replacing the 40 years old Newing and Dickinson residence buildings with new buildings to accommodate approximately 3,000 students on the East Campus of Binghamton University. The impact assessments focused on a matrix of potentially affected environmental resources, including storm water/wastewater infrastructure, threatened and endangered species, air quality, and noise.

American Marine Rail, LLP, Dredge Permitting, SEQR Environmental Assessment Statement. And Facility Plan Development. American Marine Rail Intermodal Transfer Terminal, Bronx, New York. Project director. Managed the development of facility layout and directed preparation of permits and state and city environmental regulatory review for a 5,200 tons-per-day intermodal barge-to-rail facility solid waste transfer station. Mr. Veraart supervised the preparation of a Title 6 NYCRR Part 360 Solid Waste permit application to the New York State Department of Environmental Conservation (NYSDEC), a Joint Tidal Wetland Permit from the NYSDEC and the USACE and air quality compliance, as well as compliance with other regulatory requirements**.**

South Jersey Transportation Authority (SJTA) Alternative Energy Vehicle Deployment Plan. Project Director. Directed the preparation of an AEV deployment plan for SJTA, pursuant to the SJTA Alternative Energy Management Plan, prepared by The Louis Berger Group for SJTA. Specific four areas included evaluation of Alternative Energy sources for the SJTA fleet and operations, as well as users of SJTA facilities. Alternative energy sources evaluated include electric, Compressed Natural Gas (CNG), biodiesel and hydrogen.

National September 11 Memorial, Economic Impact of National September 11 Memorial. Project director. Directed the study to analyze impact of the National September 11 Memorial operations on the economy of New York City, New York State and the U.S. Impacts are driven by Memorial operational expenditures, employee household spending and visitor spending. Assessed the effect of the Memorial on Lower Manhattan in terms property tax revenues and business revenues.

NYCDOS, Draft Environmental Impact Statement (DEIS - SEQR, CEQR), Fresh Kills Landfill, Staten Island, New York. Project director. Executive responsibility for the preparation of the DEIS for the Fresh Kills Landfill on Staten Island. For the continued operation of the 2,200-acre landfill, NYCDOS applied for a NYCRR Part 360 Permit for a solid waste management facility from the New York State Department of Environmental Conservation (NYSDEC). For this purpose, the NYCDOS submitted an EIS pursuant to both State Environmental Quality Review (SEQRA) and City Environmental Quality Review. The DEIS was deemed complete by NYSDEC prior to the City's decision to close the Fresh Kills Landfill.

RAED EL-FARHAN, PHD Principal-in-Charge

Dr. EL-Farhan, vice president of LBGs science and water resources division, has more than 20 years of experience as a consultant, professor, and university researcher. His areas of expertise include water resources, ecosystem restoration, stormwater management, water and wastewater treatment systems, water quality permitting and compliance, aquatic chemistry, and the fate and transport of contaminants in the environment. Dr. EL-Farhan has used this diverse expertise in support of EPA headquarters and its regional offices in their BEACH, EMPACT, and TMDL programs, where he has characterized, assessed, and modeled water quality; wrote and reviewed technical reports; and prepared training materials and workshops. He has worked extensively with various states to provide water resources planning services throughout the Mid-Atlantic region, and continues to support the EPA's Assessment and Watershed Protection Division through the Technical Support for the National Watershed Protection Program. Dr. EL-Farhan is working on multiple assignments with U.S. Army Corps of Engineers, Institute for Water Resources (USACE IWR), Engineer Research and Development Center (ERDC), Districts, Headquarters, and Assistant Secretary of the Army (CE) to provide technical review of feasibility studies, conduct facilitations at USACE strategic sessions, assist the USACE with development of quality of life metrics, evaluate the USACE model certification process, and evaluate and certify models. Dr. EL-Farhan is a member of the American Water Resources Association and participates in national dialogues related to water resources issues. He also serves on the planning committee of the National Conference on Ecosystem Restoration (NCER) where he has worked alongside many of the USACE restoration experts.

FIRM Louis Berger Group

EDUCATION

- PhD, Environmental Engineering
- MS, Environmental Engineering
- BS, Civil Engineering

YEARS EXPERIENCE 21
YEARS WITH FIRM 10

RELEVANT PROJECT EXPERIENCE

USACE Kansas City, Project Initiation and Planning for Programmatic EIS for the Missouri River Recovery/Restoration Plan and the Public Relations Strategy and Internal Communication Plan Needs Assessment for the Missouri River Recovery Program. Director. Dr. EL-Farhan worked closely with the project manager to coordinate the technical leads, experts, academics, and subconsultants. He not only provides management, but also technical support. He is providing technical support and is responsible for the development of the Research Compendium that will serve as the scientific guideline and basis during the alternatives development phase of the project. Also, Dr. EL-Farhan is assisting with the development of the public outreach and communications strategy and plan for implementation for the Missouri River Recovery Program. This includes both an external public relations strategy and an internal communications plan.

USACE Baltimore, Anacostia River Watershed Restoration Plan. Program manager. Managed a comprehensive watershed restoration plan for the Anacostia River Watershed; its objective is to produce a systematic 10-year restoration plan for environmental and ecological restoration within the entire watershed to mitigate the impact of stormwater runoff to the Anacostia River watershed. The plan was conducted under the USACE General Investigations Program. The study was authorized in a resolution of the Committee on Public Works and Transportation, U.S. House of Representatives.

USACE IWR, Analytical and Professional Support Services. Program manager for this $25 million, five-year contract that provides technical and analytical support services that are generally not available within USACE, including the following principal areas: program management, water resources, environmental protection and restoration, navigation, information systems, and homeland security. Under this contract and Dr. EL-Farhan's leadership, LBG is providing technical review of feasibility studies, conducting facilitations at USACE HQ strategic sessions, assisting USACE with development of quality of life metrics, evaluate the USACE model certification process and certifying models.

USACE Mobile District IDIQ for Environmental Studies for BRAC Actions. Program manager. Under $6 million IDIQ contract, Dr. EL-Farhan oversees overall project management, subcontractor management, project scheduling, quality assurance and control, deliverable production, project accountability to USACE Mobile, and maintains the administrative record. Currently working on environmental, engineering, and planning services in preparation of Phase II of the feasibility study and EIS for the ecosystem restoration and flood damage reduction for the 23 square-mile Upper Turkey Creek Basin in Kansas. Scope includes engineering analysis for the plan formulation to accomplish flood protection, environmental restoration, and improve water quality and recreational facilities.

USACE Baltimore, IDIQ for Planning Projects, Various Locations. Program manager. Under $5 million IDIQ contract, LBG is managing multiple task orders, preparing siting and facility studies and other planning documents. Specifically, Dr. EL-Farhan has worked on Potomac

Park Levee–EA and Section 106 project, for design and construction of an improved flood control project within the National Mall and Constitution Gardens in Washington, DC, to address the potential impacts to cultural and environmental resources. Also includes St. Martin Ecosystem Restoration–assisted in the evaluation of the feasibility study for aquatic ecosystem restoration in the St. Martin River Watershed in Maryland, under the authority of Section 206 of WRDA.

EPA Assessment and Watershed Protection Division, Technical Support for the National Watershed Protection Program. As program and project manager, developed dozens of watershed TMDL studies nationwide and has prepared training materials and conducted workshops. For these projects, conducted source assessment and watershed characterization to support watershed simulation and development of allocations. Presented TMDL results at a series public meetings. The Bayou Lafourche TMDLs, Louisiana included a comprehensive water quality monitoring plan, developing and submitting a QAPP for EPA's approval, setting up and calibrating Louisiana's QUAL2E model, and calculating the TMDL for the bayou.

Review of the Upper Mississippi River Illinois Waterway Feasibility Report. To help ensure the adequacy of this recommendation to Congress, Dr. EL-Farhan and the LBG team provided a review of the UMRS Chief's Report, the Rock Island District Commander's Feasibility Report, the NRC Reports on the UMRS, and related documents. The purpose of the review was to evaluate the actions proposed by the Chief of Engineers and District Commander in relation to external reports by the NRC and other parties, as well as prior Assistant Secretary of the Army (CW) correspondence to OMB to determine potential courses of action for the Assistant Secretary of the Army (CW) in transmitting his report to OMB and the Congress. The LBG report highlighted known and unknown information relevant to the ability to recommend an action to Congress, noted any deficiencies in needed information and recommended an appropriate course of action.

Transportation Research Board (TRB) of the National Academies. Senior technical reviewer. Dr. El-Farhan serves as a senior technical reviewer for the Transportation Research Board of the National Academies. He is responsible for reviewing documents and providing recommendations. Dr. El-Farhan will be reviewing papers for consideration as part of the program for the TRB 87th Annual Meeting in January 2008 and publication in the Transportation Research Record.

EPA Region 3, pH TMDL for Buckhannon River, West Virginia. Served as technical support for TMDL development for Acid Mine Drainage. Screened the available water quality data for the Buckhannon River to determine the frequency of water quality standards violation of pH and heavy metals. Reviewed models and methods applicable for predicting instream pH in streams. Developed a mass balance model based on inflow of alkalinity and acidity to predict the instream pH of the Buckhannon River.

HOPE LUHMAN, PHD, RPA Cultural Resources

Dr. Luhman manages LBG's New England and Northeast cultural resource operations from the Albany, New York, office. She is responsible for all archaeological, architectural, and historic preservation planning projects involving historic and precontact resources, as well as general business development. Dr. Luhman coordinates interdisciplinary and multitask studies; interfaces with clients and subconsultants; participates in public outreach and education programs; maintains project schedules; evaluates budgets; prepares technical reports, agreement documents, and special exhibits; and provides expert witness testimony.

FIRM Louis Berger Group

EDUCATION

- PhD, Anthropology
- MA, Anthropology
- MA, Social Relations
- BA, Anthropology

REGISTRATIONS/ CERTIFICATIONS

- Accredited by the Register of Professional Archaeologists

YEARS EXPERIENCE 28
YEARS WITH FIRM 16

RELEVANT PROJECT EXPERIENCE

Immigration and Naturalization Service (INS), Phase I and II Archaeological Survey, INS Border Patrol Station, St. Lawrence County, New York. Principal investigator.

GSA Northeast and Caribbean Region, Photographic Documentation, Phase IB Archaeological Survey, and Data Recovery Investigations, Proposed U.S. Courthouse, Buffalo, Erie County, New York. Project manager/principal investigator.

New York Army National Guard, Cultural Resource Surveys: New York Army National Guard (NYARNG). Project manager/principal investigator. Projects have included Phase IA archaeological surveys for the Rome, Lockport, Jamestown, Dunkirk, Cortland, and Dryden armories; Phase IA and IB surveys for the Walton, Kingston, Leeds, Latham, Orangeburg, Geneseo and proposed Queensbury armories; Phase IB survey for the Auburn Armory; and Phase II and III archaeological investigations for the Kingston Armory.

PARS Environmental for 77th Regional Readiness Command, Phase IB Archaeological Survey, Kerry P. Hein United States Army Reserve Center, Town of Shoreham, Suffolk County, New York. Project manager/principal investigator.

PARS Environmental for 77th Regional Readiness Command, Section 106 Compliance, Rocky Point/Brookhaven Nike Missile Launch Facility, Shoreham, Suffolk County, New York. Project manager/principal investigator.

77th Regional Readiness Command, Phase IA Archaeological Surveys, New York and New Jersey. Project manager/principal investigator.

U.S. Army Corps of Engineers (USACE) Mobile, Phase I Archaeological Survey, Fort Totten BRAC, Queens County, New York. Project manager/principal investigator.

Engineering Field Activity Northeast, Naval Facilities Engineering Command (NAVFAC), Archaeological Monitoring, Palmer Hall Geothermal Loop Field, U.S. Merchant Marine Academy, King's Point, New York. Project manager/principal investigator.

U.S. Military Academy, Cultural Resources Support, Family Housing, USMA, West Point, New York. Project manager/principal investigator.

Engineering Field Activity Northeast, NAVFAC, Archaeological Monitoring, Barry Hall Geothermal Loop Field, U.S. Merchant Marine Academy, King's Point, New York. Principal investigator**.**

Denver Service Center (DSC), Direct Labeling of Artifacts Recovered from the Archeological Excavations Conducted at Fort Stanwix National Monument for Willett Center Construction, Oneida County, New York. Project manager.

Phase I Archeological Survey, Proposed Mongaup Interpretive Center, Upper Delaware Scenic and Recreational River, Lumberland, Sullivan County, New York. Project manager/co-principal investigator and cultural resource task leader.

Archeological Survey for Roosevelt Farm Lane Rehabilitation Project, Home of Franklin Roosevelt National Historic Site, Hyde Park, Dutchess County, New York. Project manager.

Archeological Survey for the Construction Staging, Sediment Dewatering, and Sediment Dispersal Areas, Val-Kill Pond Restoration Project, Eleanor Roosevelt National Historic Site, Hyde Park, Dutchess County, New York. Project manager.

DASNY, Report on the Phase II and III Archaeological Investigations, The DASNY Site, 515 Broadway, Albany, Albany County, New York. Project manager.

DASNY, Phase IA Newing College Dormitory, State University at Binghamton, Broome County, New York. Project manager.

DASNY, Phase IA Archaeological Survey, Chenango Countywide 911 Communications System Upgrade, Chenango County, New York. Project manager.

Ammann & Whitney, and New York State Bridge Authority, Cultural Resource Services, Bear Mountain Bridge Cable Strengthening Study, Rockland and Westchester Counties, New York. Project manager.

Ammann & Whitney, Phase IA Cultural Resource Sensitivity Assessment, Proposed Amsterdam Pedestrian Bridge, City of Amsterdam, Montgomery County, New York. Project manager.

EBI Consulting, Cultural Resource Services for Wireless Carriers, New England. Contract and project management/principal investigator. On-call contract for performance of cultural resource surveys in New York, Massachusetts, New Hampshire, Vermont, Connecticut, Rhode Island, and Maine. Archaeological desk reviews, archaeological resource assessment reports, and reconnaissance/intensive surveys have been conducted throughout New York, Massachusetts, New Hampshire, Vermont, Connecticut, and Rhode Island.

USACE New England, Review of Cultural Resource Investigations, South Coast Rail Project, Southeast Massachusetts. Project manager/principal investigator.

New York State Education Department (NYSED)/New York State Department of Transportation (NYS DOT), Cultural Resource Services. Contract manager. Five-year contract (beginning 2007) to provide cultural resource services primarily associated with NYS DOT Regions 8-11, but may also include other state agency undertakings. Project-specific studies for all phases of archaeological investigations and architectural resource surveys. To date, 28 task orders received; four examples of completed projects are listed below.

- Cultural Resource Reconnaissance Survey, Site Examination and Data Recovery Plan, Shaker/Powell Hotel Site, Route 155 and Old Niskayuna Road Intersection Improvements, PIN 1132.15.101, Town of Colonie, Albany County, New York. Project manager and principal investigator.
- Archaeological and Architectural Reconnaissance Survey, Gorham Street Bridge and Approach Removal, PIN 3805.50.101, Village of Waterloo, Seneca County, New York. Project manager and principal investigator.
- Reconnaissance (Phase I) Survey, Republic Airport Development Aircraft Hangar, PIN 0903.55.101, Town of Babylon, Suffolk County, New York. Project manager and principal investigator.
- Cultural Resource Reconnaissance Survey, Jericho Turnpike, PIN 0042.27.121, Towns of Huntington and Smithtown, Suffolk County, New York. Project manager and principal investigator.

EDWARD SAMANNS, PWS, CE **Aquatic Ecology**

Mr. Samanns is the director of environmental sciences at LBG with more than 20 years of experience managing environmental investigations for a variety of projects and clients. Mr. Samanns specializes in ecological restoration/mitigation and related topics including stream and wetland ecology, permitting, threatened and endangered species studies, invasive species management, and NEPA compliance. Mr. Samanns serves as the project manager/director for several environmental and restoration contracts for public sector clients and was responsible for preparing data collection and analysis protocols, developing and implementing vegetative and hydrology monitoring methodologies, and developing habitat restoration designs. Mr. Samanns is a key member of LBG's ecological restoration unit, a unique assemblage of key scientists and engineers that have been combined to conduct restoration projects including wetland mitigation banks, endangered species habitat enhancement, coral reef creation, and tidal marsh restoration. He was the principal investigator and author of NCHRP Synthesis 302 Mitigation of Ecological Impacts (2002), is currently conducting research for NCHRP on Habitat Fragmentation, and has published/presented several papers on wetland mitigation and wildlife crossings. Mr. Samanns is also a co-author of the USACE, Waterways Experiment Station, Engineering Specification Guidelines for Wetland Plant Establishment and Subgrade Preparation (1998). Mr. Samanns also performs QA reviews of technical reports and restoration designs and provides independent research on environmental topics for clients.

FIRM Louis Berger Group

EDUCATION

- MS, Geography
- BS, Biology

REGISTRATIONS/ CERTIFICATIONS

- Professional Wetland Scientist
- Certified Geologist

YEARS EXPERIENCE 25
YEARS WITH FIRM 23

RELEVANT PROJECT EXPERIENCE

County of Rockland, Minisceongo Creek Nor'easter Repair Project, Rockland County, New York. Project manager. Responsible for overseeing the wetland and stream delineation for the project area and preparation of the Environmental Investigation Report. Also evaluated project for compliance with NEPA CATX requirements of FEMA and coordinated with project engineers to assess project alternatives to stabilize an area of mass wasting and slope failure, protect existing infrastructure from river erosion, re-establish fish passage, and establish self mitigating construction approach. Responsible for ongoing coordination of NYSDEC and ACOE permits for construction.

Marsh Resources, Meadowlands Mitigation Bank Phase 3, Carlstadt, New Jersey. Project director of the permitting, design and upcoming construction of a 60-acre tidal and freshwater wetland mitigation bank in the Hackensack Meadowlands. Responsibilities include federal and state permit application preparation and acquisition, banking instrument preparation, negotiation and approval by the interagency MIMAC, and site concept designs. Analysis has included assessment of on-site resources, functional value assessment, credit determination, innovative designs to minimize wetland fill and control invasive species, tidal data analysis and tide gate assessment. Planting plan also addressed potential treatments for acid soil conditions. Responsible for developing construction and planting plans as a design/build project employing marsh excavation and dredge methods to create enhanced tidal habitat of mud flat and low and high marsh interspersed by tidal channels and upland islands and freshwater forested wetlands.

New York Thruway Authority and NYSDOT, Stewart Airport Access Improvement, Wetland and Vernal Pool Mitigation Site Selection and Design. Project manager. Responsible for conducting a site selection and design study for the creation of 1.5 acres of vernal pool habitats within forested uplands to compensate for wetland habitat losses as requested by the NYSDEC. Evaluated physical features within project area leading to the identification of potential sites. Developed concept plans for each vernal pool site. Also responsible for the design of 15 acres of forested, scrub shrub and emergent wetlands at an off-site location. Prepared full plans and specifications to support bid documents. Additional task included preparation of a Biological Assessment for the Federal and State endangered Indiana bat along the project corridor, and coordination with the USFWS and NYSDEC.

PANYNJ, Goethals Bridge Replacement Project, Staten Island. Project supervisor. Responsible for overseeing the tasks related to the preparation of the natural resource components of a NEPA EIS and the preparation of environmental permits required for issuance of the Record of Decision by the US Coast Guard. Also supervising the wetland mitigation site selection and wetland mitigation design tasks that are necessary to support the preparation of a Mitigation Plan for the Corps permit application. Permit applications include addressing purpose and need, alternatives analysis, coastal zone consistency reviews, EFH assessments, and other topics.

USACE Baltimore District, Integrated Natural Resource Management Plan Environmental Support Services, 99th Regional Readiness Command. Project supervisor. Responsible for overseeing the preparation of an Invasive Species Management Plan and Endangered Species Management Plan as part of an INRMP for use on 184 properties in five states under the command of the 99th Regional Readiness Command. The invasive species management plan was developed to maintain compliance with EO 13112 Invasive Species and the Army Policy Guidance for Management and Control of Invasive Species. The endangered species management plan was updated to maintain compliance with the Endangered Species Act, Bald and Golden Eagle Protection Act, DoD Instruction 4715.3, and AR 200-3. The management plans address existing conditions and habitats, target species and appropriate management actions and estimated costs.

Molly Ann Brook Watershed Management Plan, Passaic County, New Jersey. Project director. Responsible for the coordination and completion of all field studies, meetings, workshops, report preparation, staffing, schedule and budget for this project. The project involves development of a Geodatabase as part of a watershed characterization effort that includes Rosgen stream reach classification, USGS Visual Assessments, and point source locations. Baseline analysis also included collection of hydrologic data and development of stream rating curves, incorporation of fecal coliform and other water quality data, benthic macroinvertebrate data, and assessments of potential nonpoint pollution sources within watershed. Prepared and conducted two public workshops to educate and gather information from interested citizens and public officials. Developed a prioritized list of effective BMP's and prepared a concept design and constructability assessment of the six best candidates for installation.

PANYNJ, Environmental Assessment, Newark Airport, Newark and Elizabeth, New Jersey. Environmental scientist. Responsible for overseeing the preparation of natural resource sections of an FAA Environmental Assessment (EA) for the expansion and modernization of Terminal A at Newark Liberty International Airport. Provided oversight of field investigations and baseline conditions analysis. In addition, provided technical input on options to minimize and mitigation wetland and open water impacts on-site through the use of innovative design options.

Brookhaven Science Associates and US Department of Energy, Peconic River Restoration Project, Brookhaven National Laboratory, Suffolk County, New York. Project manager. Responsible for the development and implementation of a Wetland Restoration Design as part of a three phase remediation of 14,700 linear feet of contaminated stream and freshwater wetlands. Also prepared and obtained NYSDEC wetlands equivalency permits, and long term monitoring plan. Project included developing a habitat assessment for the state threatened Banded Sunfish, developing and implementing protocols for the collection and transplanting of wetland plant material into restored wetlands, and collection and transplanting dormant trees using tree spades.

NYSDOT, Term Agreement for Ecological and Water Resource Studies, and Training. Project manager. Responsible for managing three consecutive four-year on-call services term agreement to provide wetland and water services to NYSDOT Regions 8, 10 and 11, and other upstate regions. Services performed include the delineation of state and federal regulated wetlands, wetland functional assessments, wetland permitting support under the New York State Freshwater Wetlands Act and Section 404 of the Clean Water Act, stream assessments and restoration design, and water quality assessments modeling. Additional services include providing training to NYSDOT staff, evaluating alternative alignments to avoid, minimize and reduce wetland impacts, evaluate wetland mitigation sites, and conducting and preparing wetland mitigation monitoring reports for submission to USACE/NYSDEC. Over one hundred task orders have been completed.

Federal Bureau of Prisons, NEPA EA/EIS Preparation for Proposed Federal Correctional Facilities Nationwide. Team leader. Conducting wetland delineations, wetland assessments, biological inventories, and impact assessments for multiple EAs and EISs for proposed federal prison facilities. Also performed Section 404/State 401 permitting and mitigation site selection and design for several of the projects. Managed staff, subconsultants, and report preparation to complete tasks on time and on budget. Projects are located in over fifteen states and have required interaction with state regulatory agencies and USFWS.

LEO TIDD **Noise, Land Use, Indirect and Cumulative Impacts**

Mr. Tidd's work at LBG has been focused on conducting environmental analyses for proposed projects and preparing documents to demonstrate compliance with state and federal environmental laws and regulations. He has been lead author and editor of complex EISs required as a result of prior environmental litigation. On these projects Mr. Tidd serves as the primary author, synthesizing the work of various technical specialists into a logical and concise narrative that addresses regulatory compliance and ensures that the lead agency took the requisite "hard look" at environmental issues. In addition, he is responsible for technical environmental analyses on topics that include, noise, indirect and cumulative impacts, air quality, habitat fragmentation/edge effects, wetlands and water resources. Mr. Tidd has completed noise impact modeling for a new connector roadway to the Atlantic City International Airport in New Jersey, as well as comprehensive noise evaluations for off-road vehicle use at the National Park Service (NPS) at Yellowstone National Park and the Lake Meredith National Recreation Area. Mr. Tidd has prepared or contributed to the indirect and cumulative impact assessments for several projects where litigation on indirect and cumulative impact issues occurred in the past or is anticipated, including the Circ-Williston Transportation Project in Vermont, the I-93 Improvements Project in New Hampshire, the Gaston East- West Connector in North Carolina, and the Birmingham Northern Beltline in Alabama. Mr. Tidd is a contributing author of the Legal Sufficiency Criteria for Adequate Indirect Effects and Cumulative Impacts Analysis as Related to NEPA Documents report prepared for AASHTO Standing Committee on the Environment as part of NCHRP Project 25-25.

FIRM Louis Berger Group

EDUCATION

- MPA, Environmental Science and Policy
- BS, Environmental Studies

TRAINING

- Transit Noise and Vibration Impact Assessment, National Transit Institute, 2011
- Highway Traffic Noise: Basic Acoustics, National Highway Institute, 2011
- EPA and FHWA Particulate Matter Quantitative Hot Spot Analysis Training, 2011
- AERMOD Dispersion Modeling Training, Lakes Environmental, 2011
- EPA and FHWA MOVES2010 Training, 2010
- EPA and FHWA Draft MOVES2009 Training, 2009
- Introduction to Transportation Conformity, National Transit Institute, 2008

YEARS EXPERIENCE 6
YEARS WITH FIRM 6

RELEVANT PROJECT EXPERIENCE

Peninsula Corridor Joint Powers Board, Dumbarton Rail Corridor Noise and Vibration Study, California. Task manager. The Dumbarton Rail Corridor Project EIS is being prepared for a proposed new rail service on a corridor spanning San Francisco Bay connecting the existing Caltrain San Jose-San Francisco line alignment in Redwood City, San Mateo County to Newark, Union City and other cities in Alameda County. The noise and vibration study being prepared by Mr. Tidd includes short-term noise monitoring at sensitive receptor locations, train and grade-crossing bell noise impact assessment using Federal Transit Administration procedures, train horn noise impact assessment using Federal Railroad Administration's horn noise spreadsheet program, and a screening analysis of bus noise impacts using FHWA's Traffic Noise Model.

NPS, Yellowstone National Park Winter Use Plan EIS, Wyoming, Montana and Idaho. Planner. Mr. Tidd was the lead author of the EIS chapters addressing the impacts of various levels of snowmobile and snowcoach use on air quality and natural soundscapes as part of the Yellowstone Winter Use Plan Draft EIS. Mr. Tidd summarized the available monitoring data to describe existing conditions in the park, and coordinated extensively with the NPS Natural Sounds program that was responsible for developing the impact thresholds and detailed soundscapes modeling effort. One key challenge addressed by Mr. Tidd was identifying the potential for cumulative impacts to natural soundscapes from actions by others, including oil and gas development in the region, aircraft overflights, and population growth/land development.

NPS, Lake Meredith National Recreation Area Off-Road Vehicle Management Plan EIS, Texas. Planner. Mr. Tidd wrote the EIS chapter describing the existing condition of natural soundscapes within two ORV areas based on monitoring data of percent time audible and sound levels. Mr. Tidd also assisted NPS with the development of soundscapes impact thresholds for the various action alternatives under consideration in the management plan and prepared the soundscapes impact assessment. The purpose of the Lake Meredith National Recreation Area Off-Road Vehicle plan/EIS is to manage ORV use in the national recreation area for visitor enjoyment and recreation opportunities, while minimizing and correcting damage to resources.

South Jersey Transportation Authority, Atlantic City Expressway/Atlantic City International Airport Direct Connector Road Noise and Air Quality Studies, Egg Harbor Township, New Jersey. Task manager. Mr. Tidd prepared air quality screening analyses based on changes in level of service and traffic volumes to address Federal Aviation Administration and conformity requirements for a new roadway and interchange in Egg Harbor Township, New Jersey. Mr. Tidd also conducted traffic noise modeling for the project using TNM2.5 and prepared the traffic noise study technical memorandum. Mr. Tidd developed the noise impact criteria for this project based on FHWA and FAA regulations. The noise modeling effort involved 41 receptor locations. In addition, Mr. Tidd prepared GIS mapping illustrating the location of environmental justice communities in the project area using 2010 U.S. Census data.

Vermont Agency of Transportation (VTrans), Circ-Williston Transportation Project EIS, Chittenden County, Vermont. Deputy project manager. The Circ-Williston EIS is a "fresh look" at a transportation project that was stopped as a result of environmental litigation just prior to construction. Mr. Tidd was responsible for editing the EIS and technical reports, creation of a comment database tracking system and was the lead author of the responses to comments on the Draft EIS and Final EIS. Mr. Tidd coordinated extensively with the various technical discipline specialists and subconsultants involved with the project to ensure a comprehensive and legally sufficient environmental documentation. Mr. Tidd's technical accomplishments on this project have included a detailed analysis of wildlife habitat edge effects and fragmentation, a GIS-based wetland mitigation site search analysis, a project-level greenhouse gas emissions analysis, and a deicing salt loading analysis.

New Hampshire DOT, I-93 Improvements (Salem to Manchester) Supplemental EIS (SEIS), New Hampshire. Deputy project manager. Mr. Tidd was the lead author of the I-93 supplemental environmental impact statement (SEIS), which was prepared in response to a court order requiring analysis of the effects of induced population and employment growth on secondary road traffic and air quality. In addition to editing all components of the SEIS, Mr. Tidd was also responsible for several technical analysis tasks, including a regional emissions sensitivity analysis for ozone precursors, and a cumulative impact analysis assessing the aggregate consequences of the project combined with other reasonably foreseeable projects and forecasted levels of population and employment growth in Southern New Hampshire. The project involves widening I-93 from two-lanes to four-lanes in each direction for a distance of 20 miles between the Massachusetts state line and Manchester, New Hampshire.

USACE, South Coast Rail EIS, Massachusetts. Planner. As part of the third-party review conducted by LBG, Mr. Tidd was responsible for the preparation of technical memorandums reviewing proposed methodologies for assessing indirect and cumulative impacts, and greenhouse gas emissions for the South Coast Rail project. Mr. Tidd was also responsible for editing portions of the DEIS/DEIR, assisting with quality assurance reviews and addressing comments on draft documents.

North Carolina Turnpike Authority, Gaston East-West Connector Indirect and Cumulative Effects Study, North Carolina. Task manager. Mr. Tidd prepared a quantitative indirect and cumulative impact assessment for a proposed toll road extending from I-85 west of Gastonia in Gaston County to I-485 near the Charlotte-Douglas International Airport in Mecklenburg County. As part of this study, Mr. Tidd defined watershed-based study area boundaries and developed metrics to translate household and employment growth into indicators for environmental impacts, such as increases in impervious surface cover and loss of forest cover. Mr. Tidd was responsible for developing and implementing the GIS-based analysis methodology for this project, as well as preparing the final technical report.

DASNY, Chenango Countywide 911 Communications Upgrade EIS, Chenango County, New York. Planner. Assisted in preparation of the SEQRA EAF, scoping document and EIS. Responsible for a GIS viewshed analysis of tower visibility using the ESRI 3D Analyst extension. The viewshed analysis included the identification of sensitive resources (e.g. parks and historic areas) within five miles of each tower. The project objective is to improve emergency services communication capabilities through the construction of six radio communication antenna towers and ancillary infrastructure, and upgrades to facilities at an additional three sites.

DANE ISMART Transportation

Mr. Ismart has 28 years experience with FHWA and 11 years with LBG. While with the FHWA, he served in many capacities including area engineer, research engineer, urban planner, and intermodal team leader. As part of the Office of Environment and Planning, Mr. Ismart specialized in systems transportation planning, intermodal planning, traffic engineering, and policy. He is a nationally recognized expert in transportation planning and models, highway capacity analysis, access management, and site impact analysis. During Mr. Ismart's tenure with FHWA, he conducted and authored the materials for more than 400 short courses on quick response urban planning models, traffic operations, freight planning and models, highway capacity, innovative highway and transit finance, transportation and environmental planning, land use planning, access management, and site impact analysis.

FIRM Louis Berger Group

EDUCATION

- MS, Civil Engineering
- BS, Civil Engineering

YEARS EXPERIENCE 28
YEARS WITH FIRM 17

RELEVANT PROJECT EXPERIENCE

Walmart versus Historic Preservation Society of Civil War Battlefields, Orange County, Virginia. Expert witness. Served as an expert witness for the Historic Preservation Society on the traffic impacts of a proposed Walmart development in Orange County, Virginia on the Wilderness Civil War Battlefield.

I-93 SEIS. Technical analyst. Developed traffic forecasts by using the New Hampshire Statewide Traffic Forecasting Model. Various scenarios are being analyzed and the results are being used for determining how well the projects purpose and scope are being met. As part of this project, an estimate of the potential changes in land use and indirect impacts due to adding capacity to the I-93 corridor are being developed.

Intermodal Terminal Innovative Finance Study. Technical writer. Developed a case study for the NCHRP study evaluating innovative funding techniques for improving access to intermodal facilities. The case study was for the Port of Palm Beach's Sky Bridge over Route 1.

Virginia Research Council. Author and instructor. Developed a financial management of federal aid course for Virginia Research Council.

Highways for Life Leap Not Creep Innovation of Technology Course. Subject matter expert technical advisor and senior instructor. Developed technical material on the application of new innovative techniques for long lasting construction and construction techniques to reduce maintenance of traffic delays and construction impacts.

FHWA, Predictive Performance of Traffic Simulation Models. Project manager. Developed a series of case studies for FHWA to assist transportation planners and traffic engineers in applying traffic simulation models. The case studies included several applications of simulation models forecasting traffic during construction as well as after completion of the projects. A brochure and how-to manual for troubleshooting the application of the simulation models to better replicate actual travel conditions was developed.

FHWA, Access Management Primer and Video. Project manager. Developed the FHWA Primer and Videotape entitled, "Safe Access is Good for Business." The primer discusses in detail methods for improving access to business during construction of corridor access improvement projects.

National Highway Institute. Instructor. Certified NHI instructor for the Federal-Aid 101 Course, Access Management Course, Innovation of Technology Course, and the Highway Capacity Course.

Update of Federal-aid 101. Author. Revised the FHWA Federal-aid 101 Course Material. The material was updated to include the latest planning, finance, construction, and environmental requirements required by SAFTEA-LU. The material and curriculum are used to train FHWA personnel.

FHWA Bottleneck Initiative Workshops. Lecturer/ technical advisor. Conducted Regional workshops and created technical material for the FHWA Bottleneck Initiative. The presentation included techniques for identifying potential corridor bottlenecks due to recurring and non-recurring events and applying innovative solutions for maintaining traffic and reducing delay.

FHWA, Operations CBU Task Order. Key technical task leader. Directed technical teams for a series of FHWA tasks orders involving intermodal planning and policy analysis, freight movements, ITS, and traffic operations.

University of Tennessee, Planning Courses. Instructor. Developed and conducted travel demand forecasting, site impact, access impact, and highway capacity courses for the University of Tennessee and the Tennessee Department of Transportation.

University of Maryland. Instructor and course developer. Developed and conducted site impact, access management, and highway capacity courses for the University of Maryland and the Maryland State Highway Administration.

Central Arkansas Regional Transportation Study. Project manager. Conducted an analysis of the 200-mile freeway system in central Arkansas. The study developed a series of recommendations for improving the freeway system. The study also includes a feasibility study of a fourth bridge crossing over the Arkansas River in Little Rock, Arkansas and a financial plan for funding.

Florida Department of Transportation. Project manager. Conducted a study to evaluate and develop recommendations for improvements to the NHS intermodal connectors of FDOT's District Six.

Klingle Road EIS, Washington, D.C. Traffic technical lead. Conducted the traffic analysis and forecast for the Klingle Road EIS. Using the MWCOG model the project estimated the traffic and traffic patterns if Klingle Road was repaired and open to traffic.

NPS Potomac Boathouse EIS, Arlington County, Virginia. Traffic technical lead. Conducting the traffic analysis to determine the traffic and parking impact for the construction of a new Boathouse facility on the Potomac in Arlington County.

Wisconsin Avenue and Military Road Phase 1 and 2 Corridor Studies, Washington, D.C. Technical director. Conducted a corridor study for the Wisconsin Ave. Corridor and the Military Road Corridor in Washington, D.C. The study developed a series of transportation improvement recommendations for improving the flow of traffic. The study included public meetings and an analysis of future land use development in the corridor.

Washington, D.C., Evacuation Planning Study. Technical model leader. Developed a system-wide traffic forecasting tool to be used in rerouting traffic during man-made and natural disasters that cause corridor or system-wide disruption of traffic.

DC Office of Planning, Washington, D.C. Comprehensive Plan. Model director. Applied the Washington DC COG model as part of the development and evaluation of the Comprehensive Transportation Plan Element.

SHRP 2 R11: Strategic Approaches at the Corridor and Network Levels to Minimize Disruption from the Renewal Process. Principal investigator. Leading the team to create the Work Zone Impact Strategy Estimation (WISE) tool and technical primer. Planning and Operations modules will assist in assessing strategies including economic impact across networks and corridors with user-defined or default value performance measures.

BRAC Bethesda Medical Traffic Study. Traffic engineer. Directing an effort to analyze the impact that the transfer of the Walter Reed staff and patients to the Bethesda Naval Center will have on the access points and internal traffic of the Bethesda Naval Center. A mitigation program to relieve future congestion on the Center is being proposed and developed.

Route 29 Corridor Study, Fauquier County, Virginia. Principal investigator. Analyzing and recommending a series of innovative corridor improvements for Fauquier County, Virginia. A report is being written and improvements such as roundabouts, directional left turns, and restricted access movements are being analyzed.

Kevin Heatley, LEED AP

Employment

2010 – current	Biohabitats, Inc., Baltimore, MD, Senior Scientist
2006 - 2010	Biohabitats Invasive Species Management, Inc., ISM Vice President
2005 - 2006	Penn State College of Technology, Williamsport, PA, Substitute Instructor, Natural Resource Management Department
2005 - 2006	Invasive Plant Control, Inc., Nashville, TN, Director of Development Northeast Region
1997 – 2005	ACRT Inc., Akron, OH, Senior Forester/Regional Manager
1984 – 1994	Bartlett Tree Experts, Lancaster, PA, Area Manager/Arboricultural Consultant

Education

Masters Environmental Pollution Control, Penn State University, Harrisburg, PA, 2006

B.S., Natural Resource Management, Cook College, Rutgers University, New Brunswick, New Jersey 1982

Professional Registration

Certified Arborist #PD-0029, 2000

LEED Accredited Professional for New Construction (USGBC), 2009

Experience

Mr. Heatley has over 20 years of experience in the environmental sector with an extensive background in ecosystem characterization, integrated vegetation management, invasive species suppression and community-based forestry. As a senior ecologist at Biohabitats, Mr. Heatley is responsible for technical and logistical oversight of restoration projects across the continental United States. His work has primarily focused upon the urban/rural interface and on incorporating green infrastructure into sustainable land use planning and management. An expert in the field of invasive species suppression, Mr. Heatley designed the first fully integrated invasive treatment prioritization model in the United States for Fairfax County, Va. He has successfully integrated resource valuation modeling into strategic and budgetary management plans for a variety of land management entities. He has also been instrumental in providing the conceptual design for a leading GIS-based vegetation management software system.

In addition to his technical expertise, Mr. Heatley is skilled at conducting entertaining and informative public speaking engagements and professional workshops. He has lectured on a variety of natural resource topics throughout the United States and the Caribbean.

Representative Project Experience

NPS Revegetation Eastern States IDIQ, Eastern US. Mr. Heatley successfully served as the Biohabitats project manager on a 2.5 million dollar National Park Service Revegetation IDIQ contract. He coordinated and lead project planning and technical assistance services on a wide variety of ecological restoration task orders including revegetation, invasive species control, plant procurement, seeding, plant protection efforts, marsh restoration, and site characterization. Biohabitats has subsequently been awarded a $20 million dollar follow-up contract for National Park Service revegetation services across the Eastern United States and the Caribbean. Mr. Heatley is currently the project manager and technical lead on this contract.

Burgundy Farm Country Day School Ecological Site Assessment, *Alexandria, VA*. Biohabitats Inc. performed an ecological assessment of the campus and developed recommendations for the sustainable use and conservation of the school's asset. Proactive identification of both ecological assets and landscape challenges enabled the School to cost-effectively integrate site ecology into the master planning process.

Fairfax County Parks Invasive Plant Site Prioritization Model, *Fairfax County, VA.* Biohabitats ISM developed a comprehensive response strategy and site treatment prioritization model as a decision-making tool to be used by the Park Authority to rank the relative value of different sites within their approximately 24,000-acre park system. Based on the principle of “protect the best first” the model shifted the focus in the parks system away from “acres treated” towards “acres restored,” allowing the County to maximize the return on its investment in invasive plant control by assuring that treatment sites reflect both the core ecological and cultural values that exist.

Lehigh University, *Bethlehem PA.* Desiring to more fully understand potential atmospheric carbon mitigation opportunities on the college campus, Lehigh University contracted with Biohabitats to undertake an analysis of the direct sequestration and avoided emissions associated with the schools landscape tree cover. Utilizing US Forest Service models, Mr. Heatley performed a comprehensive inventory of 600 acres of naturalized forest and over 220 landscape trees. Information gathered was integrated into strategic recommendations for enhancing this forest benefit and achieving a sustainable level of forest canopy.

Duke University*, Durham NC.* Concerned about the need to understand the ecological processes occurring in a high-visibility, centrally-located stand of campus woodland, Duke University contracted with Biohabitats to undertake an ecological analysis and natural capitol valuation of the campus area known as “Chapel Woods”. Mr. Heatley inventoried the vegetation, performed an assessment of the functional benefits, and developed a management plan focused upon forest sustainability. As a function of this effort, Mr. Heatley also performed invasive species suppression within the forest understory.

Valley Road Stream Restoration and Riparian Wetland Creation, *Hagerstown, MD.* Mr. Heatley provided technical recommendations and coordinated invasive plant species suppression in support of the Valley Road Stream Restoration project in Hagerstown, MD. Project involved restoration of an urbanized stream corridor and significant modification of a highly disturbed riparian plant community.

Reforestation Consulting & Invasive Species Suppression, *Rockville, MD.* In order to assure the success of a reforestation effort on a 220 acre tract in Rockville, MD., Fallsgrove Associates, a private development firm, contracted with Biohabitats ISM to oversee tree planting and invasive species suppression. Biohabitats ISM developed and implemented a sampling protocol assessing tree stocking levels and produced biannual reports on supplemental planting levels needed to assure adequate canopy cover. As a component of this effort Biohabitats ISM performed planting contractor coordination and oversight. Biohabitats ISM also created a phased, multi-year, invasive plant suppression strategy. After conducting a comprehensive evaluation of the percent cover for each of the invasive species present on the site, Biohabitats ISM created a target metric for measuring the effectiveness of invasive control efforts. Seasonally selective treatments are currently being undertaken by Biohabitats ISM.

Woodland Restoration of Episcopal High School Alexandria, *Alexandria, VA.* Driven by a desire to integrate a 35 acre woodland resource into the fabric of campus life, the Episcopal High School of Alexandria, Va. contracted with Biohabitats ISM to develop a sustainable campus forest management plan and implement invasive species suppression. This effort involved campus ecosystem characterization, functional benefits modeling, and stakeholder vision sessions. Botanical communities on campus were defined and their respective ecosystem services, in the form of air pollutant interception and carbon sequestration, quantified. Several action items identified during the plan development have subsequently been implemented by Biohabitats including; trail design and construction, ecotone modification, and invasive species suppression. Ecotone modification involved the development of a forest edge planting plan addressing issues of wind vectoring and regeneration. Invasive species interventions have been conducted during 2007 and 2008 in a phased approach designed to enhance native regeneration and minimize opportunities for additional invasive colonization of the woodland.

Episcopal High School, *Baton Rouge, LA.* Recognizing the need to integrate sustainable design principles into future development on their 40 acre campus, the Episcopal High School contracted with Biohabitats (in conjunction with NK Architects) to develop a new Master Plan for the school. Mr. Heatley coordinated Biohabitats participation and involvement in this interactive process. He was directly responsible for developing recommendations and strategies addressing stormwater retrofitting, green infrastructure expansion, and natural capital valuation.

Missionary Ridge Noxious Weed Inventory and Treatment, *Durango, CO.* During the final year of a three year project, Mr. Heatley provided technical oversight and coordinated the GPS/GIS component of the Missionary Ridge invasive species mapping and suppression effort. As part of an adaptive management approach, data collection protocols were modified and additional field staff were hired and trained by Mr. Heatley.

Woodland Management Plan for Episcopal High School, *Alexandria, VA.* Located in the Washington DC metropolitan area, the 150 years of stable land ownership at Episcopal High School has resulted in a significant legacy woodland on the campus. Recognizing the inherent educational, recreational, and inspirational value of their forest, the school contracted with Biohabitats to develop an integrated woodland management plan. The development of this plan involved a GIS-based forest stand delineation, ecological characterization, invasive plant mapping, ecosystem benefits modeling, and stakeholder vision session. As the project manager, Kevin Heatley developed the final document which provides a framework for sustainable management of this green component of the school infrastructure.

Fort Detrick, *Frederick MD.* The US Army operates Fort Detrick on over 1,200 acres of property in Frederick MD. The mixed land use pattern and competing mission objectives create special challenges regarding natural resource management. To aid in understanding field conditions and assist in budgetary justification, Fort Detrick contracted with Mr. Kevin Heatley (in conjunction with Heartwood Consulting LLC.) to undertake a resource analysis and characterization. The primary components of this project included: a GPS Landscape Tree Inventory (with tagging), GIS Database Integration, UFORE Modeling of the Environmental Impact of Forest Stands, and a Five Year Management Plan (with economic tree valuation). Mr. Heatley in addition was contracted with Fort Detrick to undertake a carbon mitigation feasibility analysis. This project examined the potential to use green infrastructure in the mitigation of vehicular greenhouse gas emissions on the base.

Representative Project Experience Prior to Biohabitats

Atkins Arboretum, *Ridgely MD.* Encompassing 400 acres on the Eastern Shore of Maryland, Atkins Arboretum is a unique facility that highlights native plant communities. With strong educational and research objectives as the primary focus of its efforts, the Arboretum enlisted the aid of Kevin Heatley (ACRT Inc.) to develop and implement a GIS-based vegetation database. Mr. Heatley supervised all aspects of the project including; high resolution aerial photogrammetry, GPS mapping of plant communities, the establishment of a thematic research plot layer, and the construction of a multi-thematic, GIS-based, vegetation database.

Tree Preservation Specifications Manual for Association for Zoological Horticulture, *Allison Park, PA.* The Association for Zoological Horticulture, an organization representing the interests of botanists, horticulturalists, and landscape professionals involved with the management of vegetation in zoological parks, contracted with Mr. Heatley for the creation of a set of standard tree preservation specifications. This document was initiated in response to excessive canopy loss during infrastructure construction and renovation projects. It was designed to promote an integrated, comprehensive approach to tree conservation appropriate for vegetation management within the challenging environment of a zoological park. It also contains an extensive specifications section suitable for use as an attachment on construction contracts.

Villanova University Five-Year Canopy Management Plan, *Villanova, PA.* Mr. Heatley as the project manager provided high resolution aerial photogrammetry, GPS/GIS vegetation and infrastructure mapping, and database design, of approximately 250 acres of this historic campus located in Villanova, Pennsylvania.

Swan Point Cemetery Five-Year Canopy Management Plan, *Providence, RI.* Mr. Heatley as the project manager provided GPS/GIS vegetation and infrastructure mapping, “seamless” GIS providing a work tracking database, and budget information of over 300 acres of this historic cemetery located in downtown Providence, Rhode Island.

Professional Associations

Society of American Foresters
International Society of Arboriculture
Society of College & University Planners

Selected Publications, Technical Reports & Presentations

Greater Everglades Ecosystem Restoration Conference, Naples, Fl, July 2010

Land Trust Alliance Annual Rally, Portland , OR, November 2009

Professional Grounds Management Society, Louisville, KY, October 2009

Mid-Atlantic Exotic Pest & Plant Council, Johnstown, PA. July 2009

Society of American Foresters, Western New York Chapter, April 2008

11th Caribbean Urban Forestry Conference, St. Croix, Virgin Islands, June 2006

St. Croix Environmental Association Tree Conservation Workshop, St. Croix, Virgin Islands, June 2006

Southeast Exotic Pest & Plant Council Annual Meeting, Raleigh, NC, May 2006

Association for Zoological Horticulture, *Tree Preservation Specifications Manual* (Industry Standard), 2005

Penn State Invasive Pest, Plants & Weeds Workshop, Luzerne County, PA, October 2005.

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CURRENT POSITIONS

2007-present Natural Resources Defense Council, New York, NY
Senior Scientist, Global Warming and Health Project
Conduct research and offer educational outreach to the public and policymakers on the impacts of climate change on health. Leads NRDC's Global Warming and Health Project. Among the scientists participating in the Intergovernmental Panel on Climate Change 2007 Fourth Assessment Report; published research has looked at heat- and smog-related health problems, climate change's effects on pollen, allergies and asthma, flooding and infectious diseases, especially among vulnerable communities.
(see www.nrdc.org/climatemaps)

2005- present Mailman School of Public Health, Environmental Health Sciences Department
Columbia University's Climate and Health Program
Assistant Clinical Professor
Teaching and research on the health impacts of climate change, and devising strategies to increase societal preparedness to cope with global warming.

2011-present: Co-Convening Lead Author for the Human Health chapter of the 2013 Synthesis of the National Climate Assessment (NCA)

2011-present: Field Editor, Epidemiology, International Journal of Biometeorology

2009-present: Chair, Committee on Global Climate Change & Health, American Public Health Association's Environment Section

EMPLOYMENT HISTORY

2001-2005 Mailman School of Public Health, Columbia University
Post-Doctoral/Doctoral Research Associate
Analyzed health impacts of climate change for the New York Climate and Health Project, multi-disciplinary program linking climate, air quality, and land use change modeling projections.

1998-2001 Queens College/CUNY, Center for the Biology of Natural Systems (CBNS)
Medical Screening Coordinator
Designed/coordinated clinical studies, administration, reporting, and recruitment for the Worker Health Protection Program, medical screening offered to thousands of nuclear weapons workers.

1996-1998 Beth Israel Medical Center, New York, NY
Project Manager
Coordinated CDC study of occupational injuries and illnesses among health care workers.

1996-1997	Office of the New York City Public Advocate, New York, NY **Researcher and co-author** (with S Mattei), *Unhealthy Closure: The Need for a Full Environmental Impact Statement on the Department of Sanitation's Long-Term Plan to Control Pollution from Fresh Kills.*
Sept.1994- Sept. 1996	Radioactive Waste Management Associates, Inc., New York, NY **Research Associate** Provided expertise as geologist and health scientist on reviews of environmental impact statements for radioactive waste disposal and decommissioning projects across the US & Canada.
June 1992- Sept.1994	Natural Resources Defense Council, New York, NY **Environmental Consultant** Researched and wrote a critique of EPA's methods for assessing risks from chemical exposures.
June 1992- Aug. 1992	Los Alamos National Laboratory, Los Alamos, NM **Research Assistant** Provided support on environmental and regulatory reviews of hazardous/radioactive waste issues.
Mar. 1978- May 1979	Colorado State Geological Survey, Denver, CO **Field Geologist** Collected and analyzed samples & conducted field surveys of uranium deposits at former mine sites.

TEACHING EXPERIENCE

2008- present	**Mentor** to Columbia University Earth Institute students on Research Projects on climate change impacts and adaptation in the New York City region, as part of an innovative Climate Change Adaptation Initiative.
2005- present	**Lecturer** on Global Warming and Health, Environmental Health Sciences Core Course, Mailman SPH, Columbia University, New York, NY; as well as at Yale University, New York University, The New School for Social Research, Rutgers University, and the University of California at San Francisco Medical School.
Fall 2006	**Mellon Teaching Fellow**, Barnard College, New York NY: Co-Instructor, "Ecotoxicology;" **Doctoral Seminar Instructor**, The Earth Institute, Columbia University, New York, NY: Public Health Seminar Leader, "Environmental Science for Sustainable Development;" **Mentor** to Barnard undergraduates on their Senior Thesis research projects
Spring 2006- 2007	**Instructor**, Mailman SPH, Columbia University, "Public Health Impacts of Climate Change;" Designed and co-taught with Dr. Patrick L. Kinney a new course offering in the Department of Environmental Health Sciences, which received a Dean's Commendation for Excellence in Teaching; and became the foundation of what has developed into Mailman's new ground-breaking Master's Program in Climate Change & Public Health, lead by Dr. Kinney.
2004- present	**Mentor** to undergraduate research interns who assist on NOAA-funded research.

Fall 2003 **Teaching Assistant**, Mailman SPH, Columbia University, “Topics in Environmental Health Science;” Co-designed and conducted masters seminars in conjunction with Prof. Kinney on climate change and health (*piloted ideas that are now being applied in Spring 2006 course*)

Fall 2002 **Teaching Assistant**, Mailman SPH, Columbia University, “Air Pollution;” helped introduce masters students to concepts of atmospheric structure, air pollution sources, regulation, and health effects

ACADEMIC RESEARCH AND TRAINING

2006-2007 “Profiling Carbon Dioxide, Pollen Concentrations and Asthma in the New York City Region,” as a 2006-2007 APERG Scholar in the Mid-Atlantic States Section of the Air and Waste Management Association (MASS-A&WMA) Air Pollution Educational Research Grant Program (APERG); *Objectives:* to investigate relationships between the timing and length of spring tree pollen seasons and hospital admissions for respiratory illnesses, and to survey spatial and temporal variations in carbon dioxide across the NY metropolitan region

2006-2007 Research investigating differences in greenhouse gas emissions from four different household types, defined by income and urban versus non-urban location

2004-2007 “Climate Variability, Air Quality and Human Health: Measuring Regional Vulnerability for Improved Decision-Making,” funded by National Oceanic and Atmospheric Administration (NOAA); *Objectives*: Assess the degree to which weather and air pollution act independently and/or jointly in contributing to health effects, and to develop and analyze highly resolved exposure and health maps over the state of New York for 1988-2002

2001-2005 “The New York Climate and Health Project: Modeling Heat and Air Quality Impacts of Changing Land Uses and Climate,” funded by US Environmental Protection Agency (EPA); *Objectives*: Develop an integrated modeling framework to assess regional climate and air quality under alternative scenarios of global climate change and regional land use change, and corresponding human health risks.

March 26-April 2 2006 DISsertations Initiative for advancement of Climate-Change ReSearch (DISCCRS) Pacific Asilomar, CA
Funded by the National Science Foundation (NSF) to meet challenges in building Successful interdisciplinary careers among recent PhD graduates in climate change impacts. One of 36 fellows selected from doctoral programs throughout the world.

July 2004 NCAR Summer Colloquium on Climate and Health, Boulder, CO (July 2004). Participated in the first summer colloquium on climate and health, held by the Advanced Study Program and Environmental and Societal Impacts Group, National Center for Atmospheric Research.

EDUCATION

October 2005 **Doctor of Public Health, Environmental Health Science**
Mailman School of Public Health, Columbia University, New York, NY

Dissertation: “Mortality in Metropolitan New York Under a Changing Climate”

Projections of future climate changes have often been made at the continental scale, yet more finely resolved projections are needed at regional scales in order for local health impacts and adaptive planning options to be evaluated. To meet these needs, a regional health risk assessment was applied to a dynamically downscaled global-to-regional model system for the tri-state New York metropolitan region. The objective was to project climate-related changes in summer heat stress and ground-level ozone concentrations and their impacts on acute mortality from all internal causes, including respiratory and cardiovascular illnesses.

The health risk assessment used model simulations of future temperature conditions and ozone concentrations developed by the New York Climate and Health Project (NYCHP). In the NYCHP model system, the NASA-Goddard Institute for Space Studies (GISS) general circulation model at 4x5° resolution was linked to the Penn State/NCAR Mesoscale Model 5 (MM5) at 36 kilometer (km) resolution to simulate future daily temperatures. The Community Multiscale Air Quality (CMAQ) atmospheric chemistry model at 36 km horizontal grid resolution was linked to the GISS/MM5 model system to simulate future daily ozone concentrations, in five summers of selected future decades across the 31-county New York metro study area. Concentration-response functions from the epidemiological literature were applied to project relative risk of heat- and ozone-related mortality in New York City in each decade. To isolate the effects of climate change on mortality, population was held constant at Census 2000 levels.

Results under the Intergovernmental Panel on Climate Change (IPCC) A2 (relatively fast-growth) scenario assumptions show that summer heat-related mortality could increase 36% by the 2020s, nearly double (95% increase) by the 2050s, and more than triple (250% increase) by the 2080s as compared to the 1990s. There is a median 4.5% increase in ozone-related acute mortality projected across the 31 counties by the 2050s. Synthesizing the heat and ozone results, for a typical summer in the 2050s, projections of additional overall mortality attributable to climate changes are 96% heat- and 4% ozone-related. The downscaled regional projections revealed heterogeneities in the temperature and ozone simulations: relatively dense population areas tend to coincide with relatively high temperatures, and relatively lower population density with relatively high ozone.

A time series analysis of daily summer mortality from 1990-1999 investigated the independent and joint effects of heat and ozone, and whether the relative risk of heat- and ozone-related mortality among urban populations exceeded that of non-urban. Poisson regression modeled daily death counts as a function of same-daily mean temperature and 1-hour daily maximum ozone concentrations averaged over the same and previous day, adjusting for day of week effects and periodic cycles. Results suggest that the heat effect (RR 1.037 per 10°F; 95% C.I. 1.028, 1.047) is less robust than ozone (RR 1.058 per 100 ppb; 95% CI 1.032, 1.085). There is a significant difference in heat-related mortality risk in urban (RR 1.062; 95% CI 1.048, 1.075) vs. non-urban (RR 1.017; 95% CI 1.006, 1.029) counties, but this is not the case for ozone. This type of health risk assessment modeling could be a useful tool for application in other metropolitan areas to evaluate the relative effects of direct (heat) and indirect (ozone) climate-health impacts that are possible under a changing climate.

June 1993	**Master of Science, Environmental & Occupational Health Science** Hunter College, City University of New York, New York, NY
January 1978	**Bachelor of Arts, Geological Sciences** Cornell University, Ithaca, NY

AWARDS

2006-2007	Air Pollution Educational and Research Grant (APERG) Scholarship Program Award recipient, to support research on the relationships between the timing and length of spring tree pollen seasons and hospital admissions for respiratory illnesses, and to survey spatial and temporal variations in carbon dioxide across the NY metropolitan region

2006	Awarded Doctoral Degree with Distinction; I.B.Weinstein Award for Academic Excellence
1993	George H. Kupchik Award, Outstanding Environmental Health Graduate; NIOSH Scholarship Recipient
1973	High School Class Valedictorian; Bausch and Lomb Science Award; NY State Regents Scholarship Recipient

JOURNAL PUBLICATIONS

As lead author:

Knowlton K, Rotkin-Ellman M, Geballe L, Max W, Solomon GM. 2011. Six Climate Change–Related Events In The United States Accounted For About $14 Billion In Lost Lives And Health Costs. Health Affairs 30(11):2167-2176 (Nov. 2011).

Knowlton K, Rotkin-Ellman M, King G, Margolis HG, Smith D, Solomon G, Trent R, English P. 2009. The 2006 California heat wave: impacts on hospitalizations and emergency department visits. *Environmental Health Perspectives* 117:61-67 (January 2009).

Knowlton K, Rotkin-Ellman M, King G, et al. 2009. The 2006 California heat wave: impacts on hospitalizations and emergency department visits. *Epidemiology* 19(6):S323(Nov. 2008).

Knowlton K, Lynn BH, Goldberg R, Rosenzweig C, Hogrefe C, Rosenthal J, Kinney PL. 2007. Projecting heat-related mortality impacts under a changing climate in the New York City region. *American Journal of Public Health* 97:2028-2034.

Knowlton K, Rosenthal JE, Hogrefe C, Lynn B, Gaffin S, Goldberg R, Rosenzweig C, Civerolo K, Ku J-Y, Kinney PL. 2004a. Assessing ozone-related health impacts under a changing climate. *Environmental Health Perspectives* 112: 1557-1563.

Knowlton K, Rosenzweig C, Goldberg R, Lynn B, Gaffin S, Hogrefe C, Civerolo K, Ku J-Y, Solecki W, Small C, Oliveri C, Cox J, Rosenthal J, Kinney PL. 2004b. Evaluating global climate change impacts on local health across a diverse urban region. *Epidemiology* 15 (4): S100-S100 (July 2004).

Knowlton K. 2001. Urban history, urban health. *American Journal of Public Health* 91(12):1944-1946.

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As co-author:

Bell, M.L., Goldberg R., Hogrefe, C., Kinney, P.L., Knowlton K., Lynn B., Rosenthal J., Rosenzweig C., and Patz J. 2007. Climate change, ambient ozone, and health in 50 U.S. cities. *Climatic Change* 82:61-76.

Chavarria G, Knowlton K, Atchley D. 2010. The human-climate-wildlife nexus. *Bulletin of the Atomic Scientists* (January/February 2010):48-56 (DOI: 10.2968/066001007).

Civerolo KL, Hogrefe C, Lynn B, Rosenzweig C, Goldberg R, Rosenthal J, Knowlton K, and Kinney PL. 2008. Simulated effects of climate change on summertime nitrogen deposition in the eastern US. *Atmospheric Environment* 42(9):2074-2082.

Civerolo KL, Hogrefe C, Lynn B, Rosenzweig C, Goldberg R, Rosenthal J, Knowlton K, and Kinney PL. 2007. Estimating the effects of increased urbanization on surface meteorology and ozone concentrations in the New York City metropolitan region. *Atmospheric Environment* 41(9):1803-1818 (Mar 2007).

Hogrefe C. S., B. Lynn, K. Civerolo, J.-Y. Ku, J. Rosenthal, C. Rosenzweig, R. Goldberg, S. Gaffin, K. Knowlton, and P.L. Kinney. 2004. Simulating changes in regional air pollution over the eastern United States due to changes in global and regional climate and emissions. *J Geophysical Res - Atmospheres* 109:D22301 (Nov 17 2004).

Hogrefe C, Rosenzweig C, Kinney P, Rosenthal J, Knowlton K, Lynn B, Patz J, Bell ML. 2004. Health impacts from climate-change induced changes in ozone levels in 85 United States cities. *Epidemiology* 15(4): S94-S95 (July 2004).

Kinney PL, K Knowlton, C Hogrefe, et al. 2007. Melding measurements and models to enrich the study of climate, air quality, and health. *Epidemiology* 18(5):S131(Sept 2007).

Kinney PL, Bell M, Hogrefe C, K Knowlton, et al. 2007. Climate change, air quality, and health: Assessing potential impacts over the eastern US. Epidemiology 18(5):S133(Sept 2007).

Patz JA, Kinney PL, Bell M, Ellis H, Goldberg R, Hogrefe C, Khoury S, Knowlton K, Rosenthal J, Rosenzweig C, Ziska L. 2004. *Heat Advisory: How Global Warming Causes More Bad Air Days*. NY: Natural Resources Defense Council.

Rosenthal JK, Sclar ED, Kinney PL, Knowlton K, Craudereef R, Brandt-Rauf PW. 2007. The links between the built environment, climate and population health: interdisciplinary environmental change research in New York City. *Ann Acad Med Singapore* 97(11):2028-2034.

Sheffield PE, Knowlton K, Kinney PL. 2011. Modeling of regional climate change effects on ground-level ozone and childhood asthma. *American Journal of Preventive Medicine* 41(3):251-257.

Ziska LH, Knowlton K, Rogers CA, Dalan D, Tierney N, Elder MA, et al. 2011. Recent warming by latitude associated with increased length of ragweed pollen season in central North America. *PNAS* 108(10):4248-4251 (March 8, 2011).

BOOK CHAPTERS

As lead author:

Knowlton K. February 10 2011. Globalization and Environmental Health. In: Nriagu JO (ed.) *Encyclopedia of Environmental Health*, vol.2, pp.995-1001. Burlington: Elseveier.

Knowlton K. April 2010 webinar presentation on "Climate Change, Vulnerable Populations and Adaptation" - Chapter 5 on Public Health Adaptation Strategy in CDC/APHA printed guidebook, *Climate Change: Mastering the Public Health Role* (in print April 2011).

Knowlton K, Hogrefe C, Lynn B, Rosenzweig C, Rosenthal J, Kinney PL. 2008. Impacts of heat and ozone on mortality risk in the New York City Metropolitan Region under a changing climate. *In:* Climate Information for the Health Sector. Advances in Global Change Research (Thomson M, Garcia Herrera R, eds.).

Hogrefe C, Ku J-Y, Civerolo K, Lynn B, Werth D, Avissar R, Rosenzweig C, Goldberg R, Small C, Solecki WD, Gaffin S, Holloway T, Rosenthal J, Knowlton K, and Kinney PL. 2004. Modeling the impact of global climate and regional land use change on regional climate and air quality over the northeastern United States. *In:* Air Pollution Modeling and Its Application XVI (Borrego C, Incecik S, eds.). New York: Kluwer Academic/Plenum, pp.135-144.

As co-author:

Kinney PL, Rosenthal JE, Rosenzweig C, Hogrefe C, Solecki W, Knowlton K, Small C, Lynn B, Civerolo K, Ku J-Y, Goldberg R, Oliveri C. 2006. "Assessing Potential Public Health Impacts of Changing Climate and Land Use: The New York Climate and Health Project." *In:* Regional Climate Change and Variability: Impacts and Responses (Ruth M, Donaghy K, Kirshen P, eds.). Cheltenham, UK and Northampton, MA: Edward Elgar, pp.161-189.

Rotkin-Ellman M, Knowlton K, Apatira L, Solomon G. 2011. "Lessons from the Past and Needs for the Future: Place-Based Case Studies of Vulnerability to Climate Change" (book chapter; in press).

Lead author of NRDC Briefing Papers & Fact Sheets on a variety of climate-health topics, including climate change's effects on ground-level ozone smog; pollen, allergies and asthma; heat waves; infectious diseases; harmful algal blooms; and strategies to help prepare to meet these health challenges; available online at: www.nrdc.org/health/globalwarming (2007-present).

PRESENTATIONS

Organizer & Moderator of Sessions on Climate Change and Health, Adaptation in Vulnerable Communities, and Indicators of Vulnerability and Resilience; for the 2011 and 2010 American Public Health Association Annual Meetings.

Organizer & Moderator of Symposia on Climate Change and Health at the 2009 and 2008 American Association for the Advancement of Sciences (AAAS) Annual Meetings.

As presenter:

Session on Climate Change, Air Pollution, and Adaptation in Vulnerable Communities; for the 2010 American Public Health Association Annual Meeting, Denver, Colorado, USA (November 2010).

Capitol Hill Oceans Week, Invited Speaker at Panel on the "Health Impacts of Today's Energy Choices," June 9, 2010, Washington, D.C.

Workshop on Modeling and Mitigation of the Impacts of Extreme Weather Events to Human Health Risks, Rutgers University, June 3, 2010 (Invited Speaker on Heat Wave morbidity, response, adaptation)

International Research Institute for Climate and Society, May 2010 and 2009, Columbia University, New York, NY, Invited Lecturer at Summer Symposium on Climate and Health.

National Environmental Public Health Conference, "Vulnerable Communities & Climate Change: Air Pollution in Metro NY" Centers for Disease Control & Prevention, Atlanta GA, October 26, 2009

National Center for Atmospheric Research Summer Symposium on Climate and Health, Invited Lecturer, July 2009.

American Museum of Natural History, New York, NY, April 2, 2009, "Exploring the Dynamic Relationship Between Health and the Environment" (poster presentation on dengue fever and climate change)

Knowlton K, Rotkin-Ellman M, King G, Margolis HG, Smith D, Solomon G, Trent R, English P. 2008. The 2006 California heat wave: impacts on hospitalizations and emergency department visits. Oral presentation at ISEE/ISEA Joint Meeting, Pasadena, CA, October 15, 2008.

Knowlton K, Kinney PL, Bell ML, Hogrefe C, Rosenzweig C. 2005. Assessing potential health impacts of ozone and $PM_{2.5}$ under a changing climate. Poster P-AQ1.8, US Climate Change Science Program (CCSP) Workshop: Climate Science in Support of Decision Making, November 14-16, 2005, Arlington VA.

Knowlton K, Rosenthal J, Rosenzweig C, Goldberg R, Lynn BH, Gaffin S, Solecki WD, Oliveri C, Cox J, Small C, Hogrefe C, CIverolo K, Ku J-Y, Kinney PL. 2004. Projecting the local impacts of global climate change on public health in New York City. American Public Health Association Annual Meeting, November 6-10, Washington, DC.

Knowlton K, Rosenzweig C, Goldberg R, et al. 2004. Evaluating global climate change impacts on local health across a diverse urban region (poster). ISEE/ISEA Mtg, 1-4 August, New York.

Knowlton K and Rosenthal J. 2004. The New York Climate & Health Project: Global and local environmental change and public health. The New York Academy of Sciences, Environment Section (10 May 2004).

Knowlton K (invited speaker). 6 Mar 2004. "Projecting Local Impacts of Global Climate Change." Long Island Univ Annual Biology Conference: The Scientific, Biological, Social, and Economic Impacts of Fossil Fuels. Brooklyn, NY.

Knowlton K, Rosenthal J, Lynn B, Gaffin S, Kinney P, Hogrefe C, Biswas J, Civerolo K, Ku J-Y, Rosenzweig C, Goldberg R. 2003. Assessing Public Health Impacts of Heat and Air Quality Under a Changing Climate in the NYC Metropolitan Area. Amer Geophysical Union Fall Mtg, 8-12 December, San Francisco. Eos Trans. AGU, 84(46), Fall Meet. Suppl., Abstract U32A-0028.

Knowlton K, Rosenthal JE, Gaffin S, Rosenzweig C, Goldberg R, Lynn B, Kinney PL. Modeling Public Health Impacts of Climate Change in the New York Metropolitan Region. Fifth International Conference on Urban Climate (ICUC-5), 1-5 September 2003, Lodz, Poland.

As co-author:

Civerolo K, Biswas J, Hogrefe C, Rosenthal J, Knowlton K, Lynn B, Ku J-Y, Goldberg R, Rosenzweig C, Kinney PL. 2004. Modeling Future Climate and Air Quality in the New York City Metropolitan Area, Presented at the Symposium on Planning, Nowcasting, and Forecasting in the Urban Zone, 84th AMS Annual Meeting, Jan. 11-15, Seattle, WA.

Hogrefe C, Lynn B, Rosenzweig C, Goldberg R, Civerolo K, Ku J-Y, Rosenthal R, Knowlton K, Kinney PL. 2005. Utilizing CMAQ Process Analysis to Understand the Impacts of Climate Change on Ozone and Particulate Matter. Models-3 Users' Workshop, September 26-28, Chapel Hill, NC. Online: http://www.cmascenter.org/html/2005_conference/abstracts/3_2.pdf.

Hogrefe C, Knowlton K, Goldberg R, Rosenthal J, Rosenzweig C, Lynn BH, Kinney PL. 2005. Integrating observations and MM5/CMAQ predictions to study the link between climate variability, air quality and health in New York State: Project description and initial results. Presented at the NOAA/EPA Golden Jubilee Symposium on Air Quality Modeling and Its Applications, September 20-21, Research Triangle Park, NC.

Hogrefe C, Civerolo K, Ku J-Y, Lynn B, Rosenthal J, Solecki WD, Small C, Gaffin S, Knowlton K, Goldberg R, Rosenzweig C, Kinney PL. 2004. Air quality in future decades – determining the relative impacts of changes in climate, anthropogenic and biogenic emissions, global atmospheric composition, and regional land use. Preprints of the 27th NATO/CCMS International Technical Meeting on Air Pollution Modeling and Its Applications, October 25 - 29, Banff, Canada, pp. 158-165.

Hogrefe C, Civerolo K, Ku J-Y, Lynn B, Rosenthal J, Knowlton K, Solecki WD, Small C, Gaffin S, Goldberg R, Rosenzweig C, Kinney PL. 2004. Modeling the Air Quality Impacts of Climate and Land Use Change in the New York City Metropolitan Area. Models-3 Users' Workshop, October 18-20, Research Triangle Park, NC. Online:

http://www.cmascenter.org/html/2004_workshop/abstracts/Climate%20Multiscale/Hogrefe_abstract.pdf.

Hogrefe C, Biswas J, Civerolo K, Ku J-Y, Lynn B, Rosenthal J, Knowlton K, Goldberg R, Rosenzweig C, Kinney PL. 2003. Climate change and ozone air quality over the eastern United States: A modeling study. Fall Meeting 2003, San Francisco, CA, December 8-12. Eos Trans. AGU, 84(46), Fall Meet. Suppl., Abstract U32A-0027.

Hogrefe C, Biswas J, Civerolo K, Ku J-Y, Lynn B, Rosenthal J, Knowlton K, Goldberg R, Rosenzweig C, Kinney PL. 2003. Climate change and ozone air quality: applications of a coupled GCM/MM5/CMAQ modeling system. Proceedings of the 2nd Models-3 Users' Workshop, October 27-29, Research Triangle Park, NC. Online at: http://www.cmascenter.org/2003_workshop/presentations/session2/hogrefe_abstract.pdf.

Kinney PL, Hogrefe C, Lynn BH, Rosenzweig C, Rosenthal J, Knowlton K. 2005. Independent and joint impacts of heat and ozone mortality risk under a changing climate. Wengen Tenth Annual Workshop on Global Change Research, September 12-14, Wengen, Switzerland.

Kinney P, Knowlton K, Rosenthal J, Rosenzweig C, Solecki WD, Hogrefe C, Lynn B, Avissar R. 2003. Heat Stress Modeling in the NYC Metropolitan Area: Estimates for the 2050s Using a Linked Global-Regional Climate Modeling System. 2003 Open Mtg: Human Dimensions of Global Environmental Change, Montreal, Canada, October 16-18.

Rosenthal JR, Kinney PL, Knowlton K. 2004. Reshaping the built environment to reduce public health impacts of the urban heat island effect. American Public Health Association Annual Meeting, November 6-10, Washington, DC.

OTHER OUTREACH, ADVOCACY, MEDIA COVERAGE

Developed NRDC webpages on *Climate-Health Vulnerability* (www.nrdc.org/climatemaps) and *2011 Extreme Weather* (www.nrdc.org/extremeweather)

December 2011 invited presentation on Climate Change, Aeroallergens and Health to the Northern Central Weed Science Society, Milwaukee, WI

2011: Webinars on Climate Change and Health for National Nurses groups for continuing medical education credits; for Faith Community Leadership groups

Nov 2011 presentation at NJ Climate Change Adaptation Workshop at Rutgers University

Oct.29-Nov.3, 2011: presentations at the American Public Health Association Annual Mtg, Washington, DC on communicating climate-health vulnerability; and organizer of two panels, including a Special Session on "Climate Change & Health: The Global Challenge"

Sept 24-25, 2011: invited presentation at workshop on health, economics, and climate change, Boston, MA

May 26-27, 2011: International Research Institute for Climate Change, Columbia University, NY, NY – Climate Change & Health presentations and trainings for international experts and researchers

March 28-20, 2011: Indo-US Heat Vulnerability Workshop, Ahmedabad, India

Invited speaker, April 2010, Barnard College panel with Dr. Mary Robinson on climate change, NYC.

January 2010 Lecture on the health impacts of global warming as part of the *Cambridge Forum* lecture series - one of public radio's longest running public affairs programs heard on NPR stations across the US - titled, "After Copenhagen," online at: http://forum-network.org/lecture/health-impacts-global-warming.

Speaking about the impacts of changing climate conditions on infectious diseases like dengue fever in a segment titled, "Outbreak" on *Planet Green* television, October 2009.

Testimony to NYC Council on climate change, infrastructure adaptation and health, May 2008.

CARE International Executive Committee Meeting, New York, NY: *Developing Responses to the Climate Crisis* (7 June 2007).

Testimony to New York City Council (Environment Committee) on climate research findings in support of proposed Local Law No.661 to limit greenhouse gas emissions in NYC (June 2006, June 2005).

The New York Times. Worked with journalists to clarify research issues: "Forecast for New York this century: Hotter and wetter" (*New York Times*, Metro Section, 27 June 2004); "Climate scientists zoom in on changes" (*New York Times*, Metro Section, 9 December 2003).

National Public Radio. "Degrees of Concern: Climate Change and New York City," K Knowlton on West Nile virus and climate variability, broadcast interview on *Living on Earth*, nationally syndicated NPR show, 11 October 2003.

The American Museum of Natural History, Dartmouth College, The 92nd Street Y (NYC), *Science News*, *Greenwire*, *New York Daily News*, *The Poughkeepsie Journal* and *Downtown Express*.

OTHER PROFESSIONAL ORGANIZATIONAL AFFILIATIONS
American Association for the Advancement of Science; American Academy of Allergy, Asthma and Immunology; American Geophysical Union; American Meteorological Society; New York Academy of Sciences; International Society for Environmental Epidemiology.

GINA M. SOLOMON M.D., M.P.H.

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EMPLOYMENT

Senior Scientist, ***Natural Resources Defense Council, 1996 - present***
Conduct research and investigation into priority environmental hazards with a focus on threats to children's health. Advocate for policy changes to improve laws and regulations to protect health. Represent NRDC in the press, legislative and agency hearings, and public fora. Supervise 7 full-time staff and numerous interns and students. Raise and manage an annual budget of over $800,000.

Director, UCSF Occupational and Environmental Medicine Residency Program, ***2008-present***
Manage all aspects of the physician training program in occupational and environmental medicine at UCSF, including directing the interview and selection process, shaping the educational requirements, managing the budget, and maintaining funding and accreditation. Supervise an associate director, program coordinator, and 4-7 residents and fellows.

Health Sciences Clinical Professor, ***University of California San Francisco, 2011 – present***
Precept occupational and environmental medicine (OEM) residents and fellows in clinic. Teach at journal club, case conference, grand rounds, and summer didactics. Teach Epi 170.16 Environment and Health course for medical and nursing students. Supervise residents from four medical centers for month-long rotations at NRDC.

Associate Director, Pediatric Environmental Health Specialty Unit, ***University of California San Francisco, 2003 - Present***

Associate Clinical Professor of Medicine, ***University of California San Francisco, 2006 –2011***

Assistant Clinical Professor of Medicine, ***University of California San Francisco, 1998 - 2006***

Clinical Instructor in Medicine, ***University of California San Francisco, 1996 - 1998***

Consultant, Ergonomics Evaluation Project, ***Massachusetts Division of Industrial Accidents, 1996 - 1997***

Fellow, Occupational and Environmental Medicine, ***Harvard School of Public Health, 1996***

Clinical Instructor in Medicine, ***Harvard University School of Medicine, 1991 - 1995***

Resident, Primary Care Internal Medicine, ***Mount Auburn Hospital, 1991 - 1995***

Research Assistant in Environmental Medicine, ***Institute of Medicine, Washington DC, 1994***

PROFESSIONAL ACTIVITIES

Science Advisory Board*, U.S. Environmental Protection Agency, 2011-2014*

Editorial Board, *Environmental Health Perspectives, 2010 – present*

Scientific Guidance Panel, *California Environmental Contaminant Biomonitoring Program, 2007-present*

Tracking Implementation Advisory Group, *California Department of Public Health, 2006 - present*

Board of Directors, *San Francisco Bay Area Physicians for Social Responsibility*, *2000 – present*

Committee on Human and Environmental Exposure Science in the 21st Century, *National Research Council, 2010 – 2012*

Board of Scientific Counselors, *National Toxicology Program*, *2008 – 2011*

California Adaptation Advisory Panel, *Governor of California*, 2010

Science Advisory Board Drinking Water Committee, *U.S. Environmental Protection Agency*, *2004-2010*

Science Advisory Board Acrylamide Panel, *U.S. Environmental Protection Agency, 2007 – 2008*

Reviewer, *American Academy for the Advancement of Sciences* LSDF 09-01: Innovative research programs to improve health and health care, 2009

Committee on Toxicity Testing and Assessment of Environmental Agents, *National Research Council, 2004 -2007*

Childhood Lead Poisoning Prevention Expert Advisory Committee, *California Department of Health Services, 2004 - 2006*

Scientific Advisory Group, Environmental Epidemiology and Biomonitoring, *CA Dept of Health Services Environmental Health Investigations Branch, 2000-2004*

SB702 Expert Working Group on Public Health Tracking, *California Department of Health Services, 2002 - 2004*

Science Advisory Board Trichloroethylene Panel*, U.S. Environmental Protection Agency, 2002*

Strategic Advisory Committee*, National Center for Environmental Health, CDC, 2001 - 2002*

Endocrine Disruptor Screening and Testing Advisory Committee, *U.S. Environmental Protection Agency, 1996 - 1998*

Board of Directors, *Consortium for Environmental Education in Medicine, 1998 - 2000*

Pesticides and Environmental Education for Health Providers Committee, *National Environmental Education & Training Foundation, 1998 - 2000*

Peer Reviewer: *Journal of the American Medical Association (JAMA); American Journal of Public Health; Climatic Change; Environmental Health Perspectives; Canadian Medical Association Journal; Environmental Science and Technology; Journal of Occupational and Environmental Medicine; Environmental Research; Environmental Geochemistry and Health; Indoor Air; International Journal of Occupational and Environmental Health; Tobacco Control; European Journal of Clinical Nutrition; American Journal of Preventive Medicine; Environmental Pollution; Chemosphere; Journal of Epidemiology and Community Health.*

EDUCATION

Masters in Public Health, *Harvard School of Public Health, 1994*
Doctorate of Medicine, *Yale School of Medicine, 1991*
Bachelor of Arts, Comparative Literature, Magna cum Laude, *Brown University, 1986*

CERTIFICATION AND LICENSING

National Board of Medical Examiners, 7/92
American Board of Internal Medicine, 8/95, Recertified 5/05
American Board of Preventive Medicine, 2/98, Recertified 12/08
California Medical License number: G 083110

AWARDS AND RECOGNITION

CAAT Recognition Award, *Johns Hopkins University Center for Alternatives to Animal Testing, 2009*
Certificate of Appreciation, *Center for Community Action and Environmental Justice, 2007*
Certificate of Appreciation, *California Safe Schools, 2004*
Clean Air Award for Research, *American Lung Association of the Bay Area, 2004*
Ten Women's Health Pioneers, *The Green Guide, 2004*
Environmental Heroes Award, *The Breast Cancer Fund, 2002*
Will Solimene Award for Excellence in Medical Writing, *American Medical Writers Association, 2000*
Occupational Physicians Scholarship Fund Award, *1993, 1995*
Farr Scholarship Award, *Yale Medical School, 1988, 1989*
Phi Beta Kappa, *Rhode Island Chapter, 1986*

SCIENTIFIC PUBLICATIONS

Knowlton K, Rotkin-Ellman M, Geballe L, Max W, Solomon G. Six Climate Change–Related Events in the United States Accounted For About $14 Billion in Lost Lives and Health Costs. Health Affairs. 30(11): 1-10. 2011.

Rotkin-Ellman M, Wong KK, Solomon GM. Seafood Contamination after the BP Gulf Oil Spill and Risks to Vulnerable Populations: A Critique of the FDA Risk Assessment. Environ Health Perspect, 2011. http://dx.doi.org/10.1289/ehp.1103695.

Solomon G, Huddle A, Silbergeld EK, Herman J. Chapter 8. Manganese in Gasoline: Are We Repeating History? In: Clapp R (Ed.). From Critical Science to Solutions: The Best of Scientific Solutions. Baywood Publishing Inc., 2011. ISBN: 978-0-89503-404-5.

Rotkin-Ellman M, Navarro KM, Solomon GM. Gulf oil spill air quality monitoring: lessons learned to improve emergency response. Environ Sci Technol. 44(22):8365-6, 2010.

Solomon G, Janssen SJ. Health Effects of the Gulf Oil Spill. JAMA, 304(10):1118-9, 2010.

Solomon G, Janssen SJ. Communicating with Patients and the Public About Environmental Exposures and Reproductive Risk. In: Woodruff TJ, Janssen SJ, Guillette LJ, Giudice LC (eds), Environmental Impacts on Reproductive Health and Fertility. Cambridge Press, Cambridge, UK, 2010.

Rotkin-Ellman M, Solomon G, Gonzales CR, Agwaramgbo L, Mielke HW. Arsenic Contamination in New Orleans Soil: Temporal Changes Associated with Flooding. Environmental Research, 110(1):19-25, 2010.

Krewski D, Acosta D Jr, Andersen M, Anderson H, Bailar JC 3rd, Boekelheide K, Brent R, Charnley G, Cheung VG, Green S Jr, Kelsey KT, Kerkvliet NI, Li AA, McCray L, Meyer O, Patterson RD, Pennie W, Scala RA, Solomon GM, Stephens M, Yager J, Zeise L. Toxicity testing in the 21st century: a vision and a strategy. Toxicol Environ Health B Crit Rev. 13(2-4):51-138, 2010.

Solomon G, Huang A, Godsel R. Contaminants in the Air and Soil in New Orleans After the Flood: Opportunities and Limitations for Community Empowerment, In: Bullard R, Wright B (eds). Race, Place, and Environmental Justice After Hurricane Katrina. Westview Press, Boulder, CO, 2009.

Solomon G. Physicians' Duty to Be Aware of and Report Environmental Toxins. Virtual Mentor, 11(6):434-442, 2009. http://virtualmentor.ama-assn.org/2009/06/ccas2-0906.html.

Knowlton K, Rotkin-Ellman M, King G, Margolis HG, Smith D, Solomon G, Trent R, English P. The 2006 California Heat Wave: Impacts on Hospitalizations and Emergency Department Visits Environ Health Perspect, 117: 61-67, 2009. http://www.ehponline.org/members/2008/11594/11594.pdf.

Woodruff T, Zeise L, Axelrad D, Guyton KZ, Janssen S, Miller, M, Miller G, Schwartz J, Alexeef G, Anderson H, Birnbaum L, Bois F, Cogliano J, Crofton K, Euling SY, Foster P, Germolec D, Ginsberg G, Gray E, Hattis D, Kyle A, Leubke R, Luster M, Portier C, Rice D, Solomon G, Steinmaus C, Vandenberg J, Zoeller T. Meeting Report: Moving Upstream: Evaluating Adverse Upstream Endpoints for Improved Risk Assessment and Decision Making. Environ Health Perspect, 116:1568–1575 (2008). http://www.ehponline.org/members/2008/11516/11516.pdf.

Humphreys EH, Janssen S, Heil A, Hiatt P, Solomon G, Miller MD. Outcomes of the California Ban on Pharmaceutical Lindane: Clinical and Ecologic Impacts. Environ Health Perspect, 116:297-302 (2008). doi:10.1289/ehp.10668.

Humphries E, Solomon G. Helping Your Patients Manage Asthma: Focus on the Source. Medscape, http://www.medscape.com/viewarticle/572573.

Solomon GM, Janssen S. Talking with patients and the public about endocrine disrupting chemicals. In: Endocrine-disrupting Chemicals: From Basic Research to Clinical Practice. Ed. Andrea C. Gore. Part of "Contemporary Endocrinology," series editor P. Michael Conn, Humana Press, Totowa, NJ, 2007.

Karr C, Solomon GM, Brock-Utne A. Health effects of common home, lawn and garden pesticides. Ped Clin N Am 54(1):63-80, 2007.

Thundiyil J, Solomon GM, Miller MD. Transgenerational exposures: Persistent chemical pollutants in the environment and breast milk. Ped Clin N Am 54(1):81-101, 2007.

Solomon GM, Hjelmroos-Koski M, Rotkin-Ellman M, Hammond K. Air quality in New Orleans, Louisiana after flooding: Mold, endotoxin, and particulate matter, October - November 2005. Environ Health Perspect 114(9):1381-1386, 2006.

Solomon GM, LaDou J, Wesseling C. Environmental Exposures and Controls, in LaDou (Ed.) Occupational and Environmental Medicine. Fourth Ed. Appleton and Lange, Stamford CT, 2006.

McDaniel P., Solomon G, Malone RE. The ethics of industry experimentation using employees: The case of taste-testing pesticide-treated tobacco. Am J Public Health 96(1):37-46, 2006.

McDaniel PA, Solomon G, Malone RE. The Tobacco Industry and Pesticide Regulations: Case Studies from Tobacco Industry Archives. Environ Health Perspect 113(12):1659-1665, 2005.

Bailey D, Solomon G. Pollution Prevention at Ports: Clearing the Air. Environ Impact Assess Review 24:749-774, 2004.

Solomon G, Humphreys E, Miller M. Asthma and the Environment: Connecting the Dots: what role do environmental exposures play in the rising prevalence and severity of asthma? Contemp Pediatrics 21(8), 2004.

Solomon GM, Hawes A, Quintero A, Widess E. Approaches to Occupational and Environmental Law in: Rosenstock L and Cullen M. (Eds.) Textbook of Clinical Occupational and Environmental Medicine, Second Edition. WB Saunders/Mosby/Churchill Livingstone, Philadelphia, 2004.

Solomon GM, LaDou J, Jackson RJ. Environmental Exposures and Controls, in LaDou (Ed.) Occupational and Environmental Medicine. Third Ed. Appleton and Lange, Stamford CT, 2003.

Solomon GM, Balmes J. Health Effects of Diesel Exhaust. Clinics in Occup & Environ Med 3:61-80, 2003.

Miller M, Solomon G. Environmental Risk Communication for the Pediatrician. Pediatrics 112:211-221, 2003.

Miller M, Solomon G. Pesticides, in: Etzel RA and Balk SJ (Eds). Handbook of Pediatric Environmental Health, Second Ed. American Academy of Pediatrics, Elk Grove Village, IL, 2003.

Solomon GM. Rare and Common Diseases in Environmental Health. San Francisco Medicine 75(9):14-16, 2002.

Solomon GM, Huddle AM. Low levels of persistent organic pollutants raise concerns for future generations. J of Epi and Commun Health. 56(11):826-827, 2002.

Solomon GM and Schettler T. Endocrine Disruption. In McCally M. (Ed.) Life Support: The Environment and Human Health. MIT Press, Cambridge MA, 2002.

Solomon GM, Weiss P. Chemical Contaminants in Breast Milk: Time Trends and Regional Variability. Environ Health Perspect 110(6): A339-A347, 2002.

Pandya RJ, Solomon GM, Kinner A, Balmes JR. Diesel Exhaust and Asthma: Potential Hypotheses and Molecular Mechanisms of Action, Environ Health Perspect 110(suppl 1):103-112, 2002.

Chaisson C, Solomon G. Children’s Exposure to Toxic Chemicals – Modeling their World to Quantify the Risks. Neurotoxicology 22:563-565, 2001.

Solomon GM, Schettler T. Emerging Issues in Environmental Health: Endocrine Disruption. Canadian Med Assn Journal 163(11): 1471-1476, 2000.

Solomon GM. Hormones, Chemicals, and Public Policy. Chem and Engineering News, 78(32): 66-67, 2000.

Schettler T, Solomon GM, Valenti M, and Huddle AM. Generations at Risk: Reproductive Health and the Environment. Massachusetts Institute of Technology Press, Boston, June 1999.

Milton DK, Solomon GM, Rossiello RA, Herrick RF. Risk and Incidence of Asthma Attributable to Occupational Exposure among HMO Members. Am J Ind Med 33(1):1-10, 1998.

Solomon GM. Reproductive Toxins: A Growing Concern at Work and in the Community. J Occ Env Med 39:105-107, 1997.

Solomon GM, Huddle AM, Silbergeld EK, Herman D. Manganese in Gasoline: Are We Repeating History? New Solutions 7(2):17-25, 1997.

Frumkin H, Solomon GM. Manganese in the U.S. Gasoline Supply. Am J Ind Med 31:107-115, 1997.

Solomon GM, Morse E, Garbo M, Milton DK. Stillbirth after Occupational Exposure to N-Methyl-2-Pyrrolidone: A case report and review of the literature. J Occ Env Med 38:705-713, 1996.

Esswein E, Trout D, Hales T, Brown R, Solomon GM. Exposures and Health Effects: An Evaluation of Workers at a Sodium Azide Production Facility. Am J Ind Med 30:343-350, 1996.

Parker J, Solomon GM. Decades of Deceit: The History of Bay State Smelting. New Solutions 5:80-89, 1995.

REPORTS

Knowlton K, Solomon G, Rotkin-Ellman M. Fever Pitch: Mosquito-Borne Dengue Fever Threat Spreading in the Americas. Natural Resources Defense Council, New York, NY, 2009. http://www.nrdc.org/health/dengue/files/dengue.pdf.

Rotkin-Ellman M, Solomon G. Poisons on Pets II: Toxic Chemicals in Flea and Tick Collars. Natural Resources Defense Council, New York, NY, 2009. http://www.nrdc.org/health/poisonsonpets/files/poisonsonpets.pdf.

Rotkin-Ellman M, Quirindongo M, Sass J, Solomon G. Deepest Cuts: Repairing Health Monitoring Programs Slashed Under the Bush Administration. Natural Resources Defense Council, New York, NY, 2008. http://www.nrdc.org/health/deepestcuts/deepestcuts.pdf.

Wall M, Rotkin-Ellman M, Solomon G. An Uneven Shield: The Record of Enforcement and Violations Under California's Environmental, Health and Workplace Safety Laws. Natural Resources Defense Council, New York, NY, 2008. http://www.nrdc.org/legislation/shield/shield.pdf.

Knowlton K, Rotkin-Ellman M, Solomon GM. Sneezing and Wheezing: How global warming could increase ragweed allergies, air pollution, and asthma. Natural Resources Defense Council, New York, NY, 2007. http://www.nrdc.org/globalWarming/sneezing/sneezing.pdf.

Cohen A, Janssen S, Solomon GM. Clearing the Air: Hidden Hazards in Air Fresheners. Natural Resources Defense Council, New York, NY, 2007. http://www.nrdc.org/health/home/airfresheners/airfresheners.pdf

Solomon GM, Nance E, Janssen S, White WB, Olson E. Drinking water quality in New Orleans: June-October 2006. Natural Resources Defense Council, New York, NY, January 2007. http://www.nrdc.org/health/effects/katrinadata/water.pdf.

Solomon GM, Rotkin-Ellman M. Contaminants in New Orleans Sediment: An Analysis of EPA Data. Natural Resources Defense Council, New York, NY, February 2006. http://www.nrdc.org/health/effects/katrinadata/sedimentepa.pdf.

Solomon GM, Campbell TR, Feuer GR, Masters J, Samkian A, Paul KA. No Breathing in the Aisles: Diesel Exhaust Inside School Buses. Natural Resources Defense Council, New York, NY, 2001. http://www.nrdc.org/air/transportation/schoolbus/schoolbus.pdf.

Solomon G, Ogunseitan OA, Kirsch J. Pesticides and Human Health: A Resource for Health Care Professionals. Physicians for Social Responsibility, San Francisco, CA, 2000. http://www.psrla.org/pahk.pdf

Solomon GM, Mott L. Trouble on the Farm: Growing up with Pesticides in Agricultural Communities. Natural Resources Defense Council, New York, NY, 1998. http://www.nrdc.org/health/kids/farm/farminx.asp.

PUBLISHED ABSTRACTS

Knowlton K, Solomon G, Chavarria G. Preparing for the Health Impacts of Climate Change: Science and Societal Strategies. AAAS Annual Meeting Abstract, 2008.

Janssen S, Solomon G, Chavarria G. Measuring Human Exposures to Hormone-Disruptors: Scientific Tools for Global Health. AAAS Annual Meeting Abstract # 090-096, 2008.

Rotkin-Ellman M, Solomon G. Soil Contamination in New Orleans: Arsenic and Lead Before and After Katrina. APHA Annual Meeting Abstract #163091, 2007.

McDaniel P, Malone R, Solomon GM. The Tobacco Industry and Pesticide Regulations. Society for Research on Nicotine and Tobacco, 10th Annual Scientific Sessions, 2004.

Solomon GM. Mercury and other Persistent Fish Pollutants: Risks to the Fetus and Child. APHA Annual Meeting Abstracts, 2003

Solomon GM. Endocrine Disruptors and Current Science Policy Developments. APHA Annual Meeting Abstracts, 4185, 2000.

Solomon GM. Special Risks to Children in Agricultural Settings. Neurotoxicology, 2000.

Solomon GM, Mott L. Disproportionate Exposures and Susceptibility: Pesticide risks to farm children. Neurotoxicology 20:1, 1999.

Solomon GM, Schettler T, Huddle A, Valenti M. Endocrine Disruptors: A lens on low dose health effects. Epidemiology 9(4): S54, 1998.

Solomon GM, Huddle AM, Schettler T, Valenti M. The Tradition of Statistical Significance: An impediment to prudent public health? Epidemiology 9(4): S75, 1998.

Solomon GM. Protecting Human Health From Endocrine Disruptors: Are toxicology and risk assessment up to the challenge? APHA Annual Meeting Abstracts, 2024, 1998.

Solomon GM. The Reproductive and Developmental Effects of Organic Solvents: The dilemma of identifying a culprit. APHA Annual Meeting Abstracts, 10, 1996.

Solomon GM, Milton DK. The Occupational Asthma Incidence Study: A pilot project. APHA Annual Meeting Abstracts, 177, 1996.

Garbo M, Milton D, Morse EP, Solomon G. From DBCP to NMP: Have we progressed? APHA Annual Meeting Abstracts, 408, 1996.

SELECTED PRESENTATIONS

Congressional Testimony and Briefings:

Cancer and the Environment
Safer Chemicals Healthy Families Congressional Briefing, 4/7/11

Cancer Clusters and the Environment
Hearing of the Senate Committee on Environment and Public Works, Washington, DC, 3/29/11

Reproductive Health and the Environment
Pew Charitable Trusts Congressional Briefing, 6/11/10

Health Effects of the Gulf Oil Spill
Hearing of the House Committee on Energy and Commerce, Subcommittee on Energy and the Environment, Washington DC, 6/10/10

Protecting Children from Environmental Threats
Hearing of the Senate Committee on Environment and Public Works, Washington, DC, 3/17/10

Endocrine Disrupting Chemicals in Drinking Water
Hearing of the House Committee on Energy and Commerce, Subcommittee on Energy and the Environment, Washington DC, 2/25/10

Biomonitoring: A Tool for Public Health Policy
American Chemistry Society Congressional Briefing, 3/09

Health Risks to Children and Communities from Recent EPA Decisions on Air and Water Quality
Hearing of the Senate Committee on Environment and Public Works, Washington, DC, 2/07

Selected TV and Radio Appearances:

Gulf Oil Spill Health Effects
PBS Need to Know, National TV, 6/10
CBS Evening News, National TV, 6/10
CNN Evening News, National TV, 5/10
CBS The Early Show, National TV, 5/10

Cancer Cluster in Fort Chipewyan, Alberta
Canadian Broadcasting Company National Radio, 5/10

Protecting Children from Toxins in the Home
Childhood Matters, KISS-FM Radio, San Francisco, CA, 7/05; 9/07

EPA's Chemical Testing Program
NPR's Living on Earth, 6/07

Protecting the Body from Heat
MarketWatch Special Report: An Investors Guide to Global Warming (Web Video), 5/07

Mold Testing in New Orleans Post-Katrina
National Public Radio, Living on Earth, 11/05
CNN News, 11/05

Diesel Exhaust Inside School Buses
National Public Radio, Science Friday, 2/01

Selected Scientific and Educational Presentations:

Children's Health and the Gulf Oil Spill
Pediatric Academic Societies Annual Meeting, 5/11

Toxicity Testing in the 21st Century
National Academy of Sciences Conference, 5/09

Biomonitoring: A Tool for Public Health Policy
UC Berkeley School of Public Health, 3/09
UCSF School of Medicine, 1/09

Preparing for Climate Change in California
UCSF Continuing Medical Education Course, 11/09
UCSF School of Medicine, 1/08, 3/09
Public Policy Institute of California, 12/08
UCLA School of Public Health, 10/07

Health Effects of Global Warming

Governor's Global Climate Summit, 9/09
Grantmakers in Health Annual Conference, 3/09
UCSF Advances in Internal Medicine Course, 5/08
California Joint Legislative Briefing, Sacramento, CA, 8/06

Health Hazards to Day Laborers
UCSF School of Medicine FCM 184, 12/08, 11/09
Clinica Martin Baro, 3/10

Taking an Environmental History
Kaiser San Francisco Internal Medicine Residents, 10/09
SFGH Internal Medicine Residents, 7/09
UCSF School of Medicine, 1/09
N245 UCSF Nursing School, 2/09
UCSF Family and Community Medicine Residents, 12/08
UCSF Integrative Medicine Course, 5/08

Pediatric Environmental Health "Toolkit" for Pediatricians
San Francisco General Hospital Pediatric Grand Rounds, 10/07
Stanford Lucile Packard Children's Hospital Grand Rounds, Palo Alto, Ca, 4/07
Oakland Children's Hospital, Oakland, CA, 5/07
O'Connor Hospital Combined Grand Rounds, San Jose, CA, 4/07
Kaiser Santa Teresa Hospital, San Jose, CA, 6/07
Kaiser Oakland, Oakland, CA, 10/06

Cancer and the Environment
Institute for Functional Medicine Annual Meeting Plenary Address, 5/10
Northern California Cancer Center, 3/08, 10/08
UCLA Ted Mann Family Resource Center Insights Into Cancer Lecture, Los Angeles, CA, 3/07

Mold Contamination in New Orleans Post-Katrina
UC Irvine Medicine Grand Rounds, 12/07
Stanford Law School, 10/07
CDC National Environmental Public Health Conference, Atlanta, GA, 12/06

Healthy Food in Healthcare
Stanford Medical School, Palo Alto, CA, 10/05, 10/06, 11/09
UCSF Medical Center, San Francisco, CA, 3/06 & 5/06
CleanMed National Conference, Seattle, WA, 4/06
John Muir Medical Center Combined Grand Rounds, Walnut Creek, CA, 3/06

Endocrine Disruptors in the Home and Community
Heinz Conference on Women and the Environment, Boston, MA, 10/06

Controlling Environmental Hazards in Communities of Color
National Legal Aid and Defenders Association Conference, Snowbird, UT, 6/06

Breastfeeding in a Contaminated World
March of Dimes Perinatal Conference, Chicago, IL, 3/06

Mercury and Current Fish Consumption Guidelines for Children
American Academy of Pediatrics Annual Conference, San Francisco, CA, 9/05

Why Should an Internist Care About Environmental Disease?
U.C. Davis Internal Medicine Grand Rounds, Sacramento, CA 7/10
Kaiser Permanente Medical Grand Rounds, San Francisco, CA, 4/04
UCSF Alice Hamilton Memorial Lecture Grand Rounds, San Francisco, CA, 3/04

BRIANA E. MORDICK

PROFESSIONAL EXPERIENCE

NATURAL RESOURCES DEFENSE COUNCIL *Washington, DC*
OIL & GAS SCIENCE FELLOW *September 2010 – Present*

Technical advisor on oil and gas related issues. Provides scientific expertise and analysis in support of advocacy efforts. Engages with and serves as a liaison to the scientific community.

ANADARKO PETROLEUM CORPORATION *January 2005 – September 2010*

Greater Natural Buttes Natural Gas Field, Uinta Basin, UT (June 2009 – September 2010)
Senior Geologist & Team Lead

- Geologist responsible for drilling 50+ wells and selecting 500+ new drilling locations
- Worked to develop new criteria and methods for selecting optimal well locations
- Lead a team of four co-workers who were responsible for two drilling rigs and hundreds of wells; organized and lead meetings; provided weekly updates to management; served as point of contact for extended team members

Salt Creek Field CO_2 Enhanced Oil Recovery Project, Natrona County, WY (Nov 2006 – June 2009)
Geologist II

- Described and analyzed core data to develop full field depositional model
- Analyzed well logs, core, and production data to determine flow pathways of oil and CO_2
- Assisted in construction of digital 3D geologic reservoir model used for oil and CO_2 flow simulation modeling

Ozona Natural Gas Field, Crockett County, Texas (Jan 2005 – Nov 2006)
Geologist I

- Geologist responsible for drilling 100+ natural gas wells, analyzing logs, and recommending zones to be completed for production
- Remapped subsurface geology, resulting in greater predictability of productive zones in wells
- Successfully presented underdeveloped natural gas prospect at the North American Prospect Expo (NAPE) and engaged a partner to develop these prospects

ANADARKO PETROLEUM CORPORATION *The Woodlands, Texas*
GEOSCIENCE INTERN *September 2004 - November 2004*

Evaluated the Baxter shale in active Wyoming oil and gas fields for shale-gas production potential.

EDUCATION

UNIVERSITY OF NORTH CAROLINA AT CHAPEL HILL *Chapel Hill, North Carolina*
MASTER OF SCIENCE, GEOLOGICAL SCIENCES *September 2002 – May 2005*

Thesis: Pyroxene thermobarometry of basalts from the Coso and Big Pine volcanic fields, California

BOSTON UNIVERSITY *Boston, Massachusetts*
BACHELOR OF ARTS, EARTH SCIENCE *September 1998 – May 2002*

Senior Thesis: Provenance of discrete ash layers from the Izu-Bonin Arc system using Laser Ablation-Inductively Coupled Plasma-Mass Spectrometry

BRIANA E. MORDICK

PUBLICATIONS

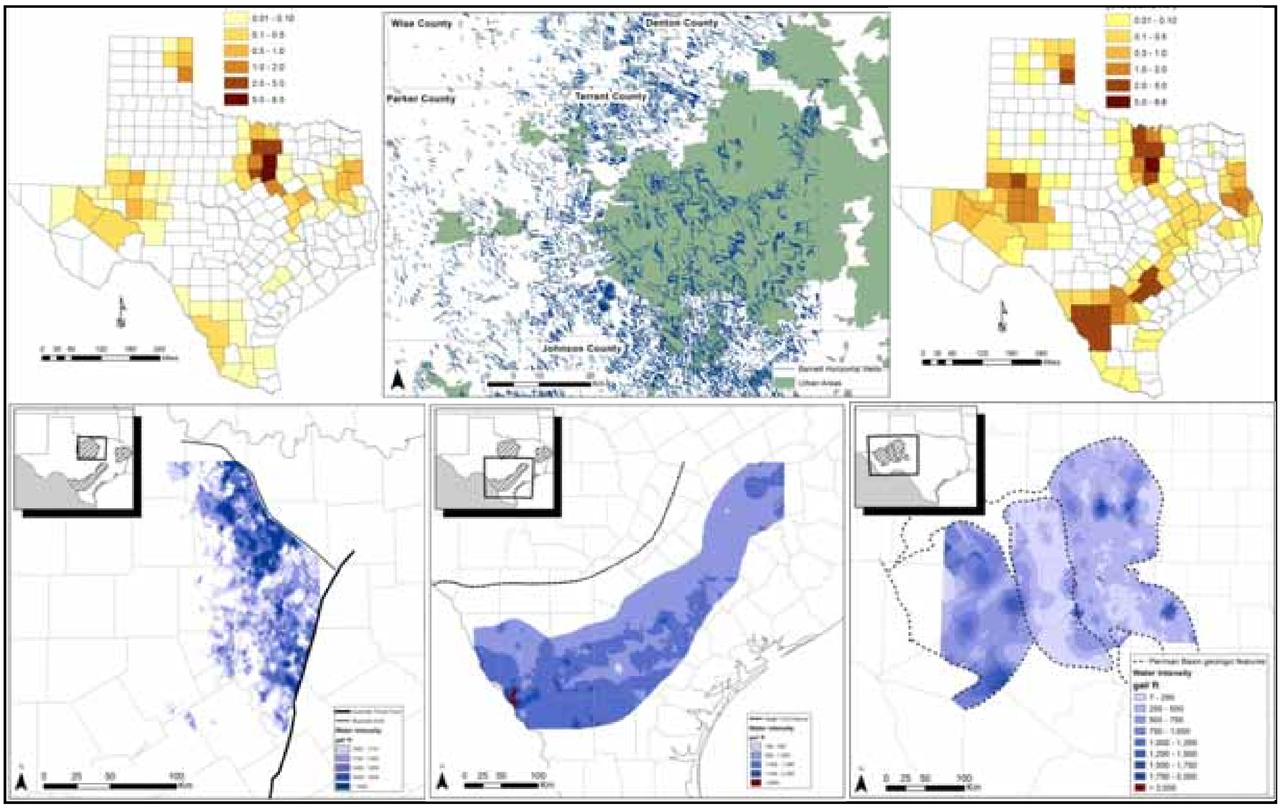
Mordick, B.E., Glazner, A.F., 2006, Clinopyroxene thermobarometry of basalts from the Coso and Big Pine volcanic fields, California: Contributions to Mineralogy and Petrology, v. 152, no. 1, p. 111-124.

SELECTED PRESENTATIONS

- October 19, 2010:
  - Forum: National Research Council of the National Academies, Board on Earth Sciences and Resources, Committee on Earth Resources
    - Meeting Title: "Meeting Our Nation's Natural Resource Needs: Balancing Risks and Rewards"
    - Presentation Title: "Environmental Impacts of Oil and Gas Production"
- March 11, 2011:
  - Forum: EPA Hydraulic Fracturing Study Technical Workshop
    - Meeting Title: Well Construction and Operations
    - Presentation & Abstract Title: "Risks to Drinking Water from Oil and Gas Wellbore Construction and Integrity: Case Studies and Lessons Learned"
- June 1, 2011:
  - Forum: Environmental Entrepreneurs Monthly TeleSalon
    - Meeting Title: "Natural Gas in the Mix: Finding the Balance"
    - Presentation Title: "Environmental Impacts of Natural Gas Production"
- September 27, 2011:
  - Forum: University of Wyoming Hydraulic Fracturing Forum
    - Meeting Title: Hydraulic Fracturing, A Wyoming Energy Forum
    - Presentation Title: Hydraulic Fracturing Best Practices: Mitigating Environmental Concerns

September 2012

Oil & Gas Water Use in Texas: Update to the 2011 Mining Water Use Report



Prepared for

Texas Oil & Gas Association, Austin, Texas

Bureau of Economic Geology
Scott W. Tinker, Director
Jackson School of Geosciences
The University of Texas at Austin
Austin, Texas 78713-8924

Oil & Gas Water Use in Texas:
Update to the 2011 Mining Water Use Report

**Jean-Philippe Nicot, P.E., P.G., Robert C. Reedy, P.G.,
Ruth A. Costley, and Yun Huang, P.E.**

Bureau of Economic Geology
Scott W. Tinker, Director
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Austin, Texas 78713-8924

Executive Summary

In Spring 2012, we undertook an update of the hydraulic fracturing sections of the TWDB-sponsored report titled "Current and Projected Water Use in the Texas Mining and Oil and Gas Industry" that we published in June 2011 (Nicot et al., 2011). The 2011 report provided estimated county-level water use in the oil and gas industry in 2008 and projections to 2060. This 2012 update was prompted by two main events: (1) a major shift of the oil and gas industry from gas to oil production, displacing production centers across the state and impacting county-level amounts; (2) rapid development of technological advances, resulting in more common reuse and in the ability to use more brackish water. The timely update was enabled by a faster than anticipated development, translating into abundant statistical data sets from which to derive projections, and by an increased willingness of the industry to participate in providing detailed information about water use in its operations. This document follows the same methodology as the 2011 report but differs from it in two ways. Our current update clearly distinguishes between water use and water consumption. The 2011 report does not include reuse from neighboring hydraulic fracturing jobs, recycling from other industry operations or other treatment plants, and use of brackish water. Our update also presents three scenarios: high, low, and most likely water use and consumption with a focus on water consumption. This update has been reviewed by the TWDB and should supersede oil and gas industry projections from the 2011 report.

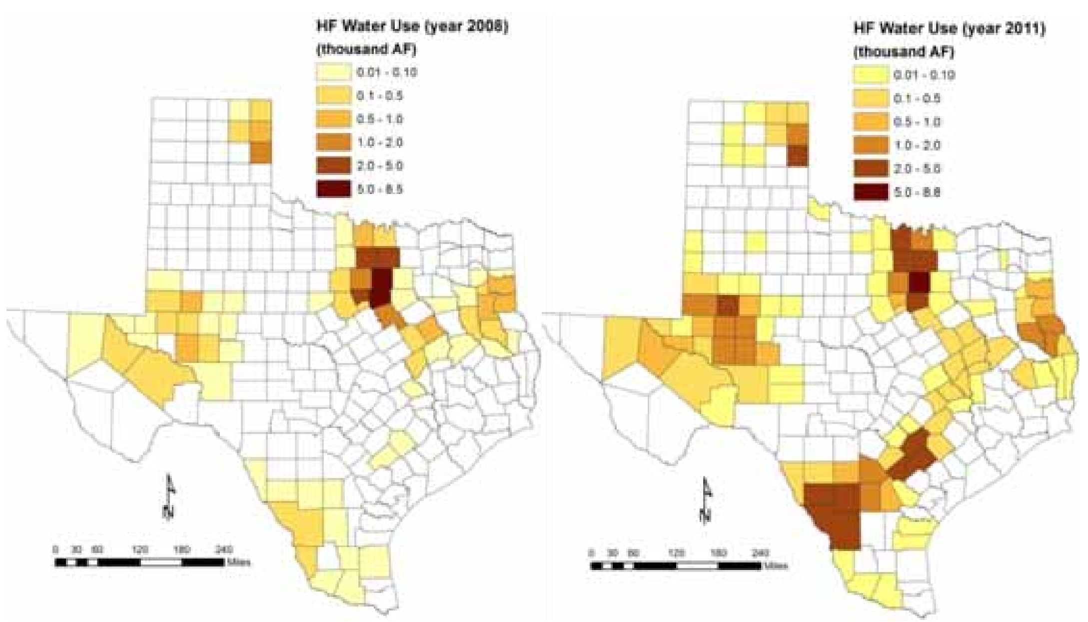

Figure ES1. Spatial distribution of hydraulic fracturing water use in 2008 (~36,000 AF) and 2011 (~81,500 AF).

Overall we find that, if the total water use for hydraulic fracturing has increased from 36,000 AF in 2008 to ~81,500 AF in 2011 (Figure ES1), the amount of recycling/reuse and the use of brackish water have also increased (~17,000 AF in 2011, or 21%). Hydraulic fracturing has expanded to the southern and western, drier parts of the state and, by necessity, the industry has had to adapt to those new conditions. Collected information tends to suggest that the industry has been decreasing its fresh-water consumption despite the increase in water use. Total water use information is relatively easy to access (through the private database vendor IHS), but true consumption is harder to gauge.

The updated hydraulic fracturing projections at the state level do not show a major departure from and are essentially consistent with the previous report but have a more subdued peak and a longer tail (Figure ES2). This is due to the increased likelihood that the industry has hydraulically fractured more formations that can be placed into the tight oil and gas category. The annual peak water use previously estimated at 145,000 AF in the early 2020's is now thought to be a broad peak plateauing at ~125,000 AF/yr during the 2020's. However, fresh water consumption is estimated to stay at the general level of ~70,000 AF/yr and to decrease in future decades. Adding other oil and gas industry water uses, such as waterflooding and drilling, brings projected maximum water use up to ~180,000 AF/yr during the 2020-2030 decade with a much lower consumption which brings the total mining water use to a maximum of ~340,000 AF/yr around the year 2030. These values remain small compared to the state water use (Figure ES3). In 2010, hydraulic fracturing water use represented about 0.5% of the water use in the state. However, the hydraulic fracturing water use is unevenly distributed across the state and may represent locally a higher fraction of the total water use.

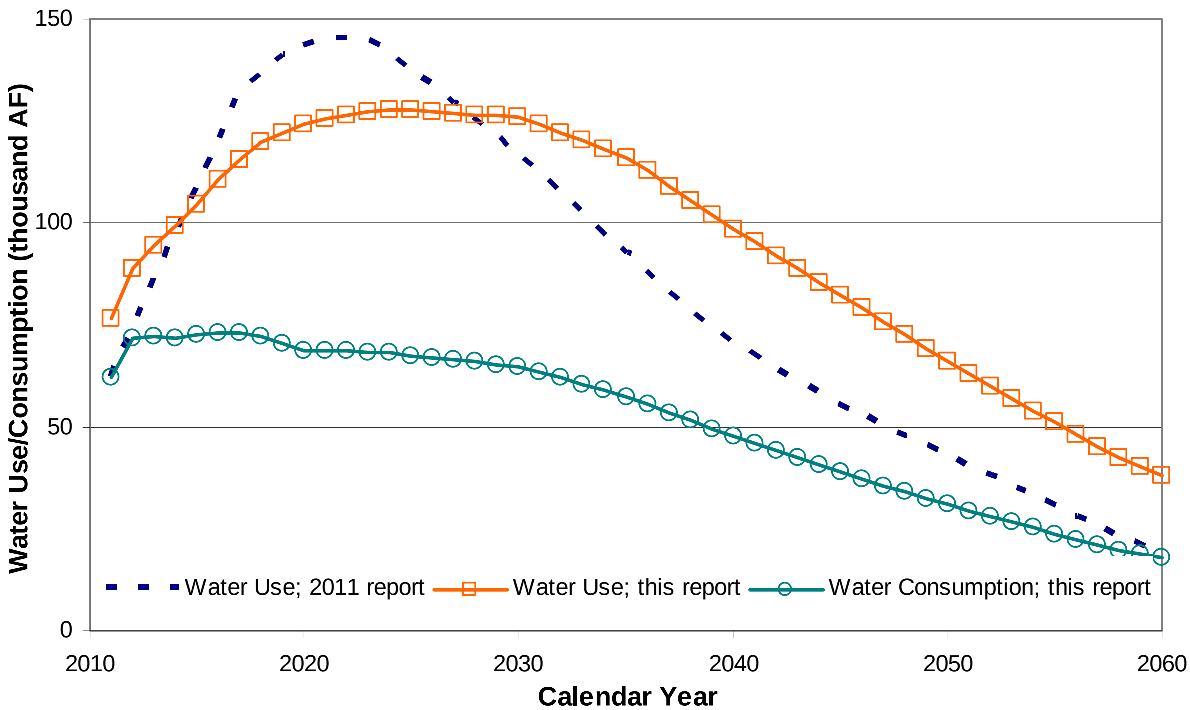

Figure ES2. State-level projections to 2060 of hydraulic fracturing water use and fresh-water consumption and comparison to earlier water projections.

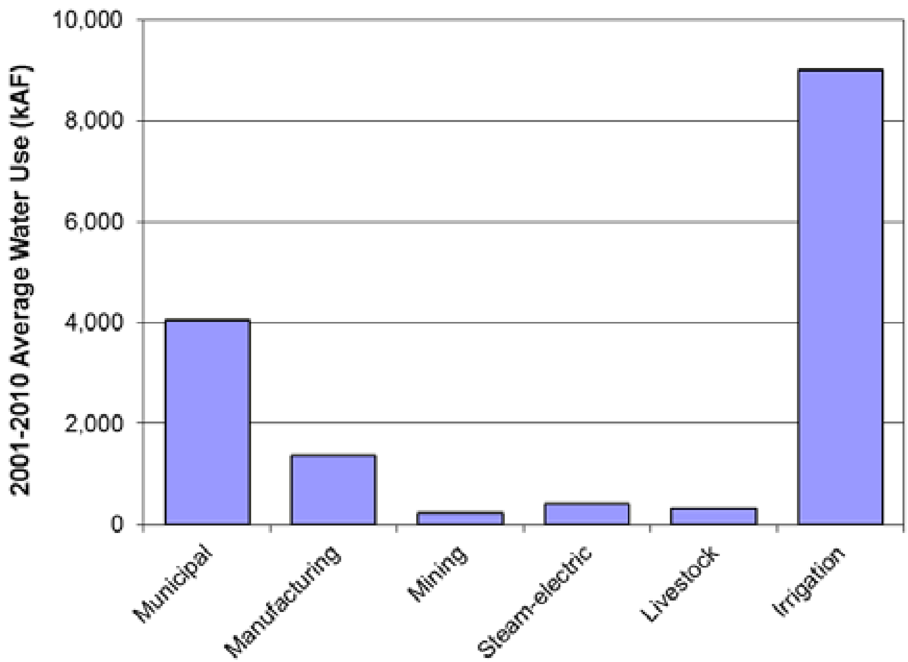

Figure ES3. Average state level water use (all categories) in 2001-2010.

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Acknowledgments

The authors would like to thank engineers and staff from many oil and gas operating companies for giving their time in answering our requests and sharing their knowledge of the hydraulic fracturing process. Special thanks to C. J. Tredway for managing the project, to Dr. Dan Hardin (TWDB) and his staff for reviewing the report, and to BEG internal reviewers, particularly Dr. Bridget Scanlon. Thanks too to L'Oreal Stepney and her staff at TCEQ for providing useful information. We are also grateful to IHS for providing free access to their Enerdeq database, which was used extensively in the course of this work. The report also benefited from a thorough editing by Amanda R. Masterson of the Bureau of Economic Geology at The University of Texas at Austin.

Acronyms

AF	Acre-foot
BEG	Bureau of Economic Geology
EOR	Enhanced Oil Recovery
Fm.	Formation
GW	Groundwater
HF	Hydraulic fracturing
kAF	Thousand acre-feet
Mgal	Million gallons
PSD	Powell Shale Digest
RRC	Railroad Commission (of Texas)
SW	Surface water
TCEQ	Texas Commission on Environmental Quality
TDS	Total dissolved solids
TWDB	Texas Water Development Board
TXOGA	Texas Oil & Gas Association

I. Introduction

This work is an update of the "Current and Projected Water Use in the Texas Mining and Oil and Gas Industry" (Nicot at al., 2011) report released in 2011 by the Texas Water Development Board (TWDB) and prepared by the Bureau of Economic Geology (BEG). The 2011 report documents future and projected water use in all segments of the mining industry: oil and gas, aggregates, coal, and other industrial and metallic substances. In particular, it looked at three main water categories in the upstream segment of the oil and gas industry: drilling, waterflooding and enhanced oil recovery (EOR), and hydraulic fracturing (HF).

How is this report different from the 2011 Report?

This report focuses on HF water use and associated drilling; the information in the 2011 report relating to waterflooding and EOR water use as well as drilling not associated with hydraulically-fractured wells did not require updating. This update also benefited from more participation from the industry, especially for information not typically available or easily extractable from state records. We also have a longer record for many plays, indicating trends and allowing for better future projections. In addition, we presented three scenarios for water use and water consumption for each play (high, medium, low) as was done in Bené et al. (2007) but not in the 2011 report. Furthermore we made the distinction between water use and water consumption more explicit. Water use is the amount of water used in an operation regardless of the water source provided; water is either fresh or brackish. Fresh water is defined as any water with a total dissolved solids (TDS) content of <1,000 mg/L; the upper limit for brackish water is 35,000 mg/L, but often in this document the limit will be <10,000 mg/L. Water consumption is fresh water use excluding recycling and reuse. Reuse is understood as the water originating from previous HF operations whereas recycling is more general and could include, for example, produced water from conventional wells or waste water obtained from other industries or municipalities.

Scope of work

As in the 2011 report, this update's scope of work includes two main tasks: (1) documenting current (year 2011) and past water use from HF; and (2) estimating projected water use. Both tasks are completed at the county level for the entire state of Texas. Task 1 consists of gathering water use data and establishing statistics needed for the projection phase in the spirit of what was done in the 2011 report but with a more detailed processing of the data. Task 2 is to produce a projection of county- level water use to 2060 using previously derived statistics and input from the industry.

This current document is organized in the following way. We first describe the methodology and its caveats as well as the challenges to making projections. We then examine the 2011 water use and compare our new findings to the 2011 projections made in 2008 as a way to validate our approach. We then present projections to 2060 according to three scenarios: high estimates, most likely estimates, and low estimates.

II. Methodology

II-1. Historical and Current Water Use

We followed a methodology similar to that used in the 2011 report, making use of the IHS Enerdeq database (http://www.ihs.com/products/oil-gas-information/data-access/enerdeq/browser.aspx). The IHS data were cross-checked with information from individual companies (number of oil/gas wells, of vertical/horizontal wells, amount of proppant) through discussion with company experts. In addition to production data, the Enerdeq database contains completion information submitted by operators to the Railroad Commission (RRC) of Texas through the W-2 and G-1 forms for oil and gas, respectively. In the best cases, and as noted by statistics provided in forthcoming sections of this report, the database contains all information of interest to us: API number, location of the well, well geometry, amount of water used, and amount of proppant used. Because, across plays, the completeness of the data is variable and because typographical errors are not infrequent, we developed several indicators for quality control: water intensity (amount of water used per unit length of lateral or useful vertical section) and proppant loading (amount of proppant per unit water volume). When either water intensity or proppant loading for a given well is out of range, the well is flagged and obvious errors corrected (for example, reporting water use in gal but displaying bbl as the unit instead of gal). Details on the approach follow.

The three primary data types used to estimate HF water volumes include reported values of fluid and proppant used to fracture each well and the total well length over which fracturing procedures were performed. Data were extracted separately from the IHS database for individual producing formations having a significant number (> ~100 to 200) of wells located in Texas that were completed between January 1, 2005 and December 31, 2011 that upon preliminary accounting had been fractured using > 100,000 gal of fluids. These include the Barnett, Eagle Ford, Haynesville, Cotton Valley, and Olmos formations, and several formations in the Anadarko Basin (Granite Wash, Cleveland, Marmaton) and the Permian Basin (Wolfcamp, Spraberry, Canyon, Clear Fork, San Andres, and Grayburg). For this analysis, the Wolfcamp and Spraberry were combined and the San Andres and Grayburg were combined.

As we did in the 2011 report we relied on the IHS database to recognize the currently active plays by downloading basic information on all wells drilled in Texas since 2010 (included early 2012 but with many gaps in the reporting). Our interest was not in computing water use but in determining those plays with enough activity to warrant a more detailed study. Many additional wells were fractured in other plays and did count toward the total water use in 2011, but they were not part of the detailed analyses of those plays cited earlier. Those minor plays are, however, accounted for in the general Gulf Coast and Permian Basin count.

II-1-1 Indicator for Quality Control

For producing formations having a sufficient number of wells completed during this period, the data were analyzed by annual intervals. Wells having actual or estimated total HF water use of <100,000 gal (i.e., small-scale traditional fracturing performed primarily on vertical/directional wells) were omitted from calculations as they account for comparatively insignificant water volumes compared to the fracturing currently being practiced in many plays. This minimum volume distinction was applied to vertical/directional wells only, and all horizontal wells were included in the estimates.

Critical evaluation and editing of the raw data was required. The purpose of the editing process was, through a step-wise logical procedure, to exclude wells that used or (in the absence of accurate data) were likely to have used <100,000 gal of HF fluids while retaining and accounting for wells that used or (again, in the absence of accurate data) were likely to have used ≥100,000 gal of HF fluids. For many wells, one or more of the reported data values is absent, incomplete, or inaccurate, due either to clerical errors or to partial reporting (omission errors). Clerical errors include the incorrect assignment of units (gal vs. bbl, lb vs. ton, etc.) and/or typographical errors. Omission errors primarily include the non-reporting or under-reporting of fluid volumes (proppant amounts seem to be accurately reported much more consistently than fluid volumes).

The data were screened for errors by examining ratios between the different values, including the total reported volume of fluids used per linear foot of the total fractured well depth interval (water use intensity, gal/ft), the total mass of proppant per total volume of HF fluids (proppant loading, lb/gal), and the total mass of proppant per linear foot of the total fractured well depth interval (proppant intensity, lb/ft). These ratios were examined for outliers and inaccuracies by sorting hierarchically through the data based on the various ratios. Edits were performed on the raw data where rectifiable errors could be identified, the most prevalent consisting of modifying units where such changes resulted in ratios consistent with other similar wells. In some cases, sufficient details were reported in the data comments to correct inaccurate data values, although this type of edit was extremely limited.

In general, proppant loading (lb/gal) was used as the primary data screening ratio because of the generally consistent reporting of total proppant amounts. HF fluid volumes resulting in proppant loading values (average of all stages) >5 lb/gal were deemed as under-reported. Barring a unit's error, these values generally reflect reported fluid volumes that include only acid treatments and in some cases raw gel product volumes and do not also include the volumes of water used. For vertical/directional wells having reported proppant amounts and with absent or under-reported HF volumes, wells with <100,000 lb of proppant were excluded from the estimates based on an assumed 1.0 lb/gal loading ratio.

A finer level of resolution in the water use data could be achieved by binning the hydraulic fracturing stages into slickwater, gel, and cross-linked gel systems with the latter two having a smaller water use intensity. Unfortunately the database does not allow for an accurate count in each category. The information, however, was used in a qualitative way, checking its consistency with common practices in a play.

Following the data screening and editing procedures, the data were classified into two main groups: 1) wells judged to have accurately reported fluid volumes and 2) wells judged to have inaccurately reported fluid volumes. The average (annual) water use intensity (gal/ft) values of the Group 1 wells were multiplied by the (annual) sum total fractured length (ft) of the Group 2 wells to produce annual estimates of the total water use of the Group 2 wells. The average intensity values represent truncated averages based on 90% of the data that were calculated by eliminating values less than the 5th percentile or greater than the 95th percentile of the Group 1 population to reduce the impacts of extreme values. The Group 2 annual total estimates were then added to the Group 1 annual total values to produce estimates of actual annual total water use. Values are reported for the major producing formations listed above by year and by county. County locations were assigned based on the wellhead coordinates.

A separate estimate using the same procedures was calculated for the HF water used during 2011 for all wells meeting the minimum 100,000 gal criteria but that were not completed in one of the producing formations listed above and for which insufficient data exist for temporal trend analysis.

II-1-2 Hydraulically-fractured Length

HF lengths for individual wells were determined using five approaches, each relying on different information in the database. All five approaches were applied to varying degrees to determine horizontal well HF lengths while only the first two were applied to vertical/directional wells. The first approach used the difference between the minimum and maximum reported test treatment depths and is referred to as the "test" length. This was the primary length used in an estimated minimum of 95% of all wells. The second approach used the difference between the minimum and maximum perforation depths, which was identical in most cases to that of the test length and is referred to as the "perf" length. The "perf" length was used in place of the test length in a few cases that resulted in more realistic use intensity values. The test and "perf" lengths are considered to be the most accurate length information available for most wells.

A third approach utilized the survey information and is referred to as the "survey" length. In this approach, the angle relative to the horizontal plane between successive well survey points was calculated. The horizontal length of the well was determined as the difference between the minimum depth at which that angle became less than 2.5 degrees and the maximum well depth. This approach also provided the average depth of the horizontal well section and additionally the beginning and ending X-Y coordinate locations of the horizontal well section used to map well density in GIS for the various plays. If no information was available to calculate a test or perf length, the survey length was considered to be the next-best available length information. In most cases where all three were available, the survey length is in good agreement with both the test and perf lengths. This value was used only in a few cases where neither a test nor a perf length was available.

A fourth length value was calculated as the difference between the reported driller's well depth and the bottom hole true depth, referred to as the "true value" or "TV" length and a fifth length value was calculated as the simple horizontal linear distance between the X-Y coordinates of the well surface and bottom hole coordinates ("GIS" length). Both of these values are considered to be only general estimates of the horizontal section length and were used in a very limited number of instances where more accurate information was not available. For a very few instances (<<1%) no length values were available for a given well. In these cases, the annual (truncated) average well length for that producing formation was assigned.

The fourth and fifth approaches, simpler to use, were adopted in the 2011 report. The HF water intensity for horizontal wells is computed slightly differently from the approach in the 2011 report. Instead of using the distance between the wellhead of the toe of the lateral, we used a shorter distance defined by the operator-defined "test length" more representative of the true length of the lateral. The test length is consistent with the "test" length but consistently smaller by 10 to 25%. The lateral length value matters as it used to compute water intensity, itself used to make projections. There is relatively little difference between the different approaches (Figure 1) but the “test” approach used in this document is systematically smaller than the “GIS” approach used in the 2011 document, that is, water intensity values reported in this document are systematically greater than those in the 2011 report. The median value of water intensity using the “test” and “survey” approaches are 26% and 23% larger than the “GIS” median value (Figure 2) in the Barnett Shale play. The “test” water intensity median in the Eagle Ford play is 16% larger than the “GIS” median value (Figure 2d).

II-1-3 Beyond the Database

In the 2011 report we made the explicit distinction between shale plays and tight gas plays. Although, as explained in the 2011 report, there are real differences between them, from an operational standpoint the difference is blurred (for example, wells taping Wolfcamp shale oil and Spraberry tight oil) and, in this update, we did not try systematically to assign one of either category to some plays.

For each of the plays with sufficient data we extracted yearly information, presented in the Results Section, about:

- Total number of wells
- Total water use, including estimation of data gaps
- Average/median length of laterals
- Water use in Mgal/ft
- Water intensity in gal/ft
- Proppant loading in lb/gal

The IHS database provides only water use, that is, the amount of water used during a given HF job regardless of the water source(s). In actuality, water can come from several sources. It can be “new” water or it can also be recycled or reused water. “New” water can be surface water or groundwater or it can be from an alternative source such as municipal water or treated waste water. Water also be fresh (<1,000 mg/L) and its use can directly compete with other more conventional users (municipal use, irrigation use). It can be brackish or even more saline than sea water (that is, >~35,000 mg/L). Water consumption is simply defined as the water use which is not from recycled or reused water and from which brackish and saline water use is taken out. Note, however, that this simple definition does not capture a more complex reality. Use of brackish water in areas with limited fresh water supplies could compete with conventional users. This document does not try to sort out such issues; we simply define water consumption as water use minus recycled/reused water volumes and minus brackish or saline water volumes.

Access to detailed information about water sources on the provider side is difficult. Large water suppliers do not necessarily track the ultimate usage of their water. Groundwater conservation districts (GCD’s) do not always collect information about withdrawal amounts and eventual use of the water. A request to the Texas Commission on Environmental Quality (TCEQ) on reuse of treatment water yielded a helpful list of facilities but not the amount of water transferred, and further this does not account for direct reuse at a site. The demand side, that is, operators, is very fragmented.

We collected information not present in the IHS database but of interest to TWDB and the general public about: (1) nature of the water source (river, lake, city water, groundwater, stock pond/gravel pit / quarry, wholesaler, treated industrial waste water) and it status (private, public). The ultimate goal is to determine the groundwater and surface water (GW/SW) split. Optimally, this issue would be resolved at the county level but it may not be possible; (2) amount of water injected from reuse of flow back water, recycled water can include water from commercial and municipal waste water treatment facilities; (3) TDS of the new water [fresh (<1000 mg/L), slightly brackish (1000-3000 mg/L), brackish (3000-10,000 mg/L or 10,000-35,000 mg/L), saline (>35,000 mg/L)].

In this document, we applied to all counties within a play / region the same brackish water use, recycling/reuse fraction, and GW/SW split. Undoubtedly, this is an approximation but the amount of information available does not allow accurate assessments at the county level.

II-2. Future Water Use Projections

The 2011 report followed a mixed approach to estimate projected water use, the so-called resource-based and production-based approaches. Although both approaches are somehow interdependent, we believe that the resource-based approach gives the best results and is used in this document. As described in more details in the 2011 report, it consists of four steps:

(1) Gather historical data in terms of average well water use and average well spacing. It is important to establish these elements through time to see trends rather than just focusing on the past few months.
(2) Estimate ultimate well density across the play; it is a function of several factors, such as geological prospectivity (for example, within play core or not, shale thickness) and cultural features (urban/rural). In this step, ultimate boundaries of the play are identified.
(3) Compute approximate total number of wells needed.
(4) Distribute through time and space, constrained by the assumed number of drilling rigs available (see earlier comment).

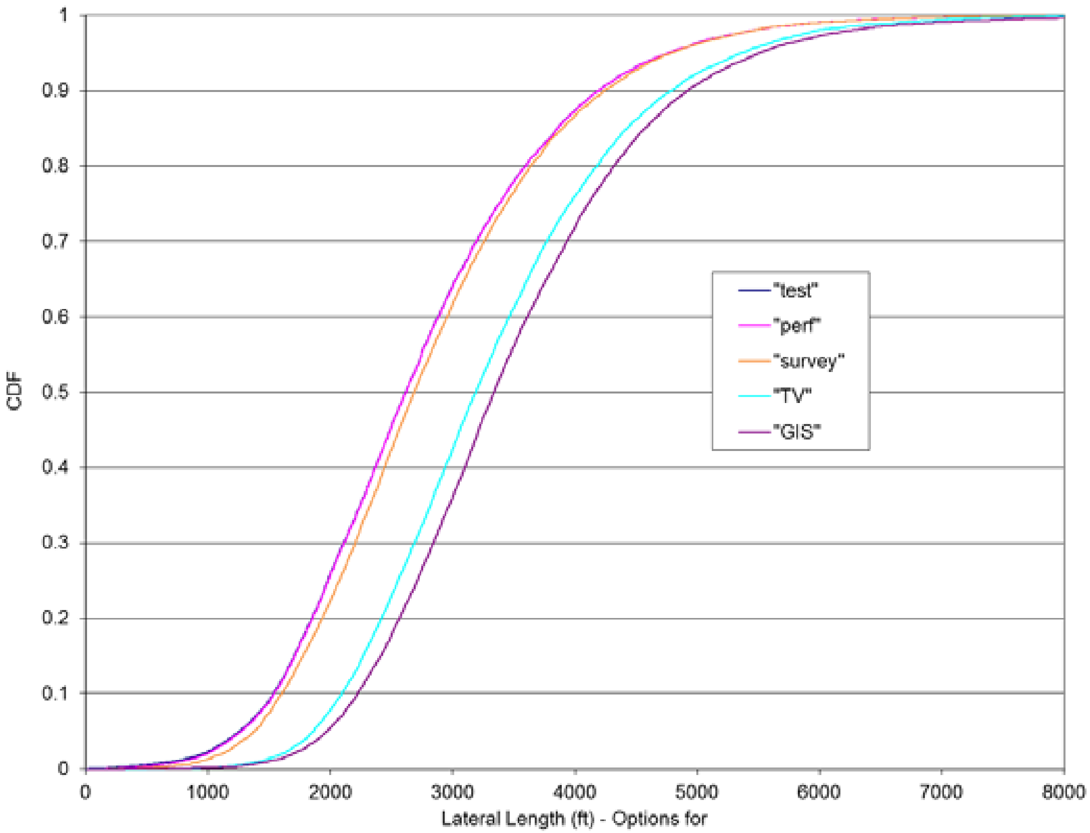
After obtaining water use, correction factors to account for recycling/reuse and use of non-fresh water are applied. We asked industry operators for projected recycling/reuse, brackish water use, and groundwater / surface water split in 2020. Given the rapid pace of change in the industry, the values obtained are somewhat speculative. Although not a guarantee for accuracy, those values are, however, consistent with what industry observers report and consistent with our own knowledge of treatment techniques and state of surface water and groundwater withdrawals across the state. The basic reporting unit for the water use projections is the county. Projections for recycling / reuse, brackish water use beyond 2020 to 2060, were made accounting for the typical current volume of flow back (limiting reuse) and for brackish water resources / lack of fresh water in the area of interest.

As discussed in the 2011 report, despite our best efforts, it is likely that the projected water use amounts will be more accurate at the play than at the county level. As done in the 2011 report, we did not assume any repeat HF, as discussions with industry experts and recent publications (Sinha and Ramakrishnan, 2011) suggest that little repeat HF will take place.

The 2011 report provides only one annual estimate. However, in an earlier report on the Barnett Shale only (Nicot and Potter, 2007; Bené et al, 2007), BEG made use of high, medium, and low water use scenarios. The different scenarios were based on various level of prospectivity and anticipated gas price. This update also makes use of three scenarios, high, most likely, and low water use, but in addition to prospectivity and gas price, they take into account level of recycling/reuse and use of brackish and saline water.

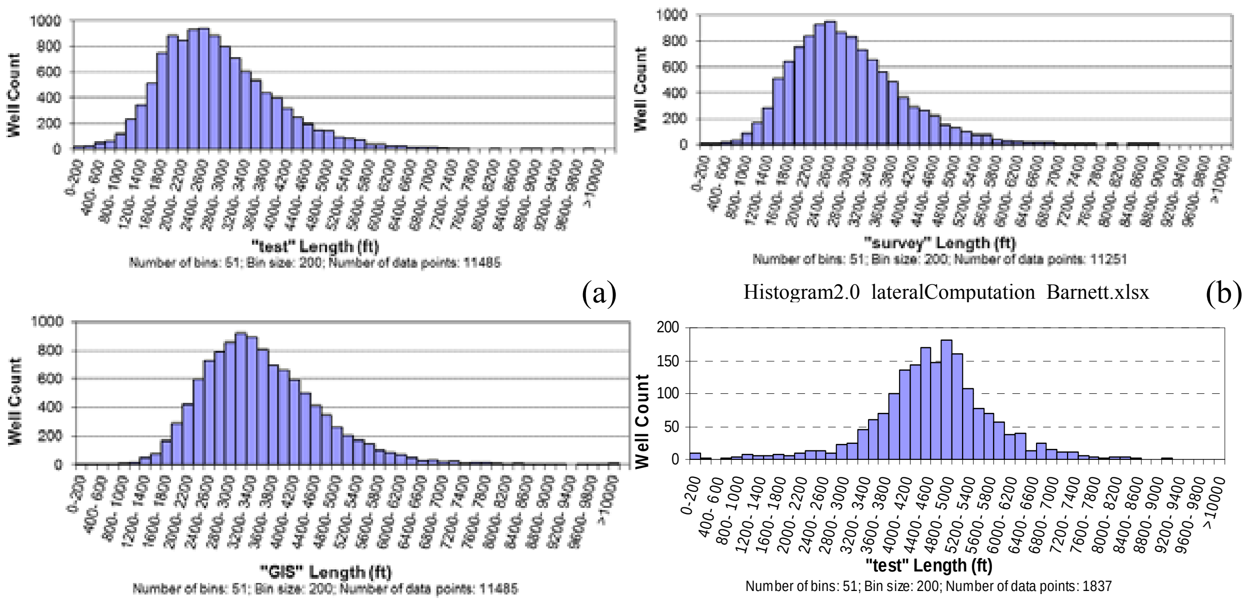
II-3. Notes on Collected Information

We obtained information on all the major plays, some with better coverage, by contacting operators. Fraction of HF wells drilled by contacted operators in the 2010-2012 period is documented by play and provides an estimate of the uncertainty. The coverage (Table 1) was calculated by adding the number of wells completed in the 2010-early 2012 period by contacted operators and normalizing that sum by the total number of wells completed during the same period. We collected information about recycling/reuse, use of brackish water, surface water/groundwater split. Coverage varies from 40% (Barnett Shale) to 10.5% (Permian Far West). Consistency in information from operators in a given play suggests that even low percentages are representative of the industry as a whole in that play despite some variability among operators (Figure 3). The figure shows a slight overall increase in water use intensity with increasing depth but it also shows that operators can have different approaches.



Histogram2.0 lateralComputation Barnett.xlsx

Figure 1. Comparison of five approaches to computing lateral length (Barnett Shale play).



(a) Histogram2.0 lateralComputation Barnett.xlsx (b)

(c) Histogram2.0 lateralComputation EagleFord.xls (d)

Figure 2. Histograms of lateral lengths according to various approaches: (a) “test”; (b) “survey”; (c) “GIS” (Barnett Shale play); and (d) “test” (Eagle Ford Shale play).

Table 1. Representivity of collected information

Play/Region	Consumption information (%)
Permian Far West	10.5%
Permian Midland	23%
Anadarko Basin	11%
Barnett Shale	40%
Eagle Ford Shale	31.2%
East Texas Basin	14.5%
All Plays	27.2%

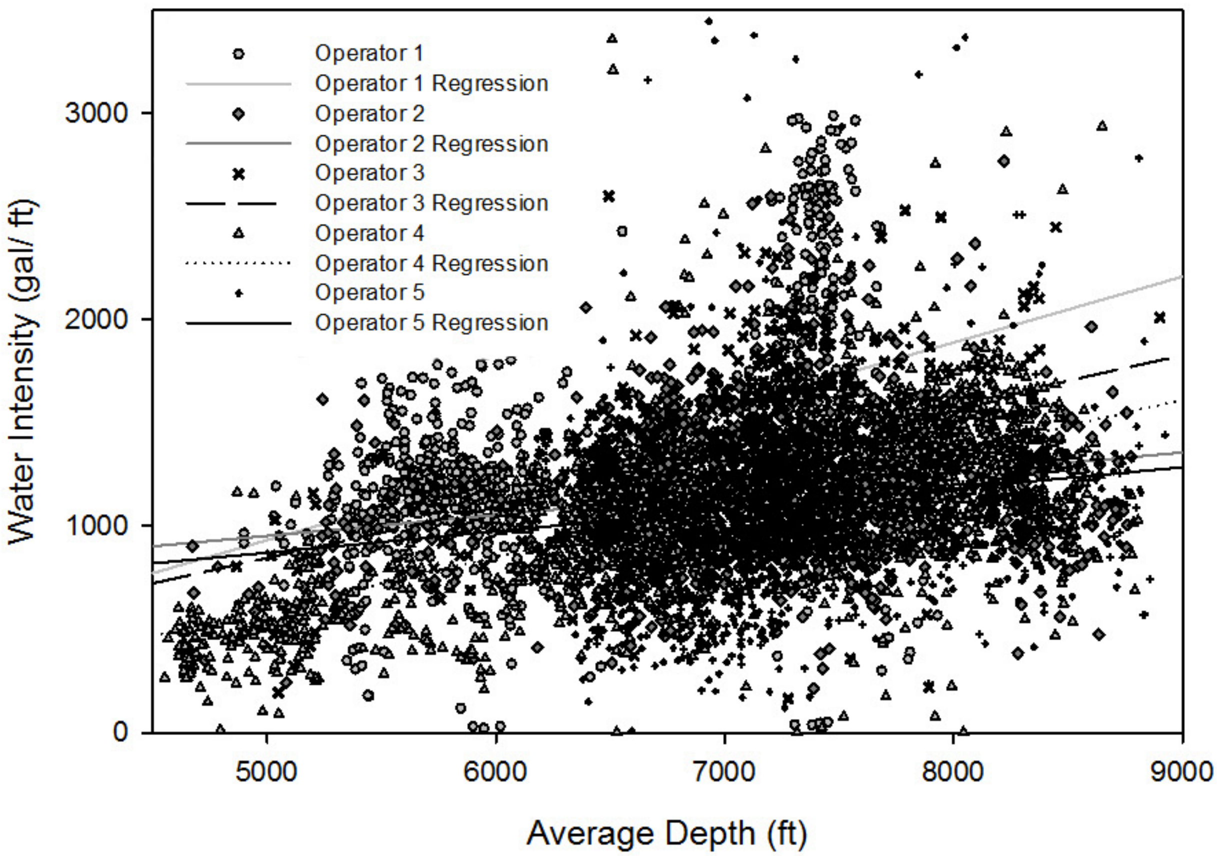


Figure 3. Water use intensity in the Barnett Shale play, showing comparison among between top operators in the play.

III. Historical and Current Water Use

After a short description of the major HF plays in Texas (Section III-1), we present water use and consumption numbers (Section III-2) that we compare to findings of the 2011 report (Section III-3). We also briefly address drilling water use (Section III-4).

III-1. Play Description

In this section we describe relevant features of each play which will then be used in the Projections Section (Section IV). Note that water use intensity and proppant loading values represent an average of the sometimes time-varying mix of slickwater / gel systems applied to the play at a given time. For example, a decrease in water use intensity may mean a better water efficiency in a technique or a move to a more water-efficient technique.

III-1-1 Barnett Shale

The Barnett Shale is the first in Texas and around the world to submit to intense slick-water HF since the mid-1990's, first using vertical wells. After a transition period, Barnett Shale operators use currently horizontal wells almost exclusively. After a strong growth in the mid-2000's (>2000 wells completed per year), the play has seen a relative decrease in the total number of wells completed in a year (Figure 4a) because of the reduced demand following the economic slump and the decreasing price of gas. Although drilling activity has abated at the edges of the play core, it is very vigorous in the core itself (Denton, Johnson, Tarrant, and Wise counties) and has considerably picked up in the so-called combo play in the northern confines of the play in Cooke and Montague counties. A weekly newsletter, the Powell Shale Digest (PSD; May 29, 2012) noted a sharp increase in oil production since mid-2010. Substantial amounts of oil and condensate have made those counties attractive to operators. Overall the total amount of water used is relatively steady at 25 kAF/yr (Figure 4b). The Barnett play is the Texas play with the highest degree of reporting water use at >90% (Table 2). Note that the bottom four plots of composite Figure 4 (as well as on similar figures in this document) show the fraction of wells used to compute the parameter on the secondary axis. High well reporting, allied with the large number of wells, gives us confidence that the water use values are particularly accurate in this play. The length of the laterals has been slowly increasing in the past few years (~3,500 ft in 2011) with a concomitant water use increase (Figure 4c and d). However water intensity (water amount per unit length) has stayed steady at ~1,200 gal/ft (Figure 4e). Note that the water intensity as reported in this document is higher than that reported in the 2011 report because of a slight change in computing it (see Section II-1-2). In contrast to water intensity, proppant loading has been increasing slightly over time to ~0.8 lb/gal in 2011 (Figure 4f).

In order to better understand water intensity and in an effort to modulate it across a play, we plotted water intensity against depth and thickness (Figure 5a and c). The trend seems upwards with increasing depth and thickness but is very noisy and tenuous at best. Water intensity appears to be rather dependent on the well operator (Figure 5b) and, thus, somehow difficult to vary across a play. Nevertheless, spatial distribution of water intensity shows a higher intensity in Denton County and in the eastern half of Wise County, areas in which the Barnett is the deepest as well as in Montague County in the oil window (Figure 6a).

In agreement with our methodology, it is also useful to understand the cumulative length of laterals in a given area or within a county. A key input to the projected water use is to assume that the entire county will be hypothetically drilled up by parallel laterals extending from one side of the county to the other side and at regularly spaced intervals (at, for example, a 1,000- ft interval [see Nicot et al., 2011 for details]). Figure 6b displays such density of well laterals, which is fairly high in Johnson County and the southern half of Tarrant County. The average lateral spacing, which is simply the inverse of the lateral density, is shown in Figure 7 and detailed in Table 3 (it is calculated in those sections of the county with an actual shale footprint). The county with the highest relative cumulative length of laterals (Johnson County) yields an average spacing between assumed parallel laterals of ~1,700 ft. This is still removed from the operational distance between laterals of 1,000 ft or even 500 ft, suggesting that this county, despite its past activity will still see further significant activity as illustrated by the coverage gaps in Figure 8. The decrease in well completion activity in Johnson County as seen in Figure 9a is more related to price gas than to a true depletion of the resource in the county.

III-1-2 Eagle Ford Shale

The Eagle Ford Shale play has seen tremendous development in the past 2 years. Initially started as a new Barnett Shale, it quickly turned into a different type of play when the extent of the oil window became clear. In addition to the fast increase in wells completed (~1,400 in 2011) (Figure 10a) and the subsequent increase in water use at ~24 kAF in 2011 (Figure 10b), the Eagle Ford Shale has the unique feature among all the plays examined in this document to experience a sharp decrease in water intensity (Figure 10e) decreasing almost in half in 4 years to ~850 gal/ft in 2011. This is seemingly due to operational changes moving from high-volume slick water HF operations to gel fracs that can carry as much proppant with much less water. The use of cross-link gels for oil production requires a higher proppant loading (Fan et al., 2011). This decrease in water intensity combined with an increase in average lateral length (~5,000 ft, Figure 10c) still translates into a decrease in water use per well to ~5 million gallons/well (Figure 10d). Not surprisingly, the proppant loading has considerably increased to 1 lb/gal in 2011 (Figure 10f). The question we will not try to answer despite its relevance to water use projection is how transferable to other plays is this switch to gel fracs and whether it could happen elsewhere on a large scale. The percentage of wells with consistent data sets is only ~47% (Table 2), making the Eagle Ford data set more uncertain that than of the Barnett Shale.

The cross-plots of water intensity vs. depth and thickness are inconclusive and even misleading (Figure 11a and b). They show no real trend except perhaps a decrease in water intensity with depth. However, Figure 12a clearly shows a higher water intensity in the down dip sections of the play, suggesting an intensity as high as 1400 gal/ft in the gas-rich area and 800 gal/ft in the oil-rich area. Densities of lateral (Figure 12b) and average lateral spacing (Figure 13, Table 4) suggest that the Eagle Ford Shale play has two cores: next to the Mexican border in Dimmit, LaSalle, and Zavala Counties and south of San Antonio in Karnes and De Witt Counties. The low average lateral spacing (>10,000 ft) suggests that many more wells will be drilled and completed there in the future.

III-1-3 TX-Haynesville Shale and East Texas Basin

This document deals only with the Texas section of the Haynesville Shale. In East Texas the Haynesville is a deep gas play, despite a report that one company has located a liquid-rich area in the Haynesville in Panola County with 350 horizontal drill sites (PSD, May 29, 2012). These are expensive wells, but they are located in an area with multiple stacked formations amenable to

HF. The Texas section of the play has seen a quick increase in the number of wells drilled (~250 in 2011, Figure 14a) and a subsequent increase in water use (~1.6 kAF, Figure 14b). This play, with the Cotton Valley Fm., also in East Texas, has the smallest fraction of wells with usable data (32% in 2011, Table 2). Lateral length (~5,00 ft), well water use (~8 million gal/well), and water intensity (~1,400 gal/ft in 2011) have all increased in the past 3 years (Figure 14c, d, and e) whereas proppant loading has stayed stable at 0.8 lb/gal (Figure 14f). Water intensity as a function of depth and thickness does not show any reliable pattern (Figure 15). Water intensity (Figure 16b) and density of lateral (Figure 16c) are spatially correlated. The highest correlations are in Harrison County and where Shelby and San Augustine counties meet (Harrison, Shelby, San Augustine, and Panola counties are all in the TX-Haynesville core area). County-level average lateral spacing (Figure 17and Table 5) with a minimum value at ~24,000 ft suggests that many more wells will be completed in this play.

III-1-4 Permian Basin

The Permian Basin, comprising the Midland Basin to the East and the Delaware Basin to the West, with the Central Platform in between, has a long history of mostly oil production. It has also received much attention recently because of hydraulically fractured vertical wells in the so-called Wolfberry play (Wolfcamp and Spraberry, Figure 18). More recently, attention has shifted to horizontal wells in the Wolfcamp Shales (Figure 19), one of the source rocks of the many oil accumulations in the Permian Basin. Several other plays are also being hydraulically fractured in the basin such as the Canyon Formation (Figure 20), the Clear Fork Formation (Figure 21), and the San Andres (Figure 22 and Figure 23) among others.

The Wolfberry was the first play in the Permian Basin to benefit from the technological progress made in the Barnett Shale play. The wells are vertical and have grown from <500 wells/yr to >1,500 wells in 2011 (Figure 18a). The annual amount of water use had also increased to almost 8 kAF in 2011 (Figure 18b). Approximately 80% of the wells have consistently good data. As the length of the productive vertical section has increased from 1.500 ft to >2,500 ft in the past few years (Figure 18c), so has the average water use per well which is >1 million gal/well in 2011, relatively small volume compared to that of horizontal wells in shale plays. As productive sections become longer, the water intensity increased slightly to ~400 gal/ft (Figure 18e), but proppant loading remained constant at ~0.9 lb/gal (Figure 18f). Water intensity seems to be higher in the Wolfberry of the Delaware Basin (Figure 24a), but that basin contains very few wells (Figure 25a), (and they might even be misnamed). The well density is the highest in Glasscock and Reagan Counties.

Slick water horizontal wells have been jumped in 2011 from a low level of <50 wells/yr to 160 wells (Figure 19a), with a concomitant increase in total water use (~1.5 kAF in 2011, Figure 19b). Lateral length (~5,000 ft in 2011), well water use (~5 million gal/well in 2011), and water intensity (800 gal/ft in 2011) all increased too (Figure 19c, d, and e), but average proppant loading stayed steady at ~1 lb/gal (Figure 19f). Water intensity is higher in the center of the Midland Basin (Figure 24b), and the density of lateral is the highest in Ward County (Figure 25b) but the average lateral spacing is still very high at ~23,000 ft (Figure 26), which suggests that many wells remain to be drilled and completed.

Other, less publicized plays also received increased interest, as shown by water intensity rising or remaining steady (Figure 20e, Figure 21e, Figure 22e, and Figure 23e). Other plays, not targeted for the same scrutiny, have also seen a development of HF. They were included in a miscellaneous file that included all fractured wells not included in a targeted play. Overall the Permian Basin has a high fraction (~85%) of wells with a consistent data set (Table 2), thus giving us confidence that that the water use values are relatively accurate (especially for those formations hosting a large number of wells).

III-1-5 Anadarko Basin

The Anadarko Basin contains several formations of interest, in particular the Granite Wash (Figure 27) but also the Cleveland and Marmaton formations (Figure 28 and Figure 29). Similarly to the development of the horizontal wells in the Wolfcamp in an area where HF was done on mostly vertical wells, the Anadarko Basin is seeing a shift toward horizontal wells. The Granite Wash has seen an increase from a few horizontal wells in 2006 to >300 in 2011 (Figure 27a) with a parallel increase in water use to <4 kAF in 2011 (Figure 27b). In the same time the length of the lateral has grown to ~4,500 ft (in 2011) (Figure 27c) and the average well water use to >5 million gallons (Figure 27d). Water intensity has reached a value of ~1,200 gal/ft (Figure 27e), but the proppant loading has remained steady at ~0.6 lb/gal (Figure 27f). The Cleveland and Marmaton horizontal wells display a similar evolution but for a smaller number of wells (~150 and ~40, respectively) and smaller water intensity at ~300 gal/ft (Figure 28e and Figure 29e). the fraction of wells with directly usable information was calculated at ~70% (Table 2). Water intensity as a function of depth failed to show a clear trend (Figure 30 and Figure 31).

Spatial distribution of Granite Wash water intensity (Figure 32a) and density of lateral (Figure 32b) confirms that Wheeler County is the most attractive county. At the county level, Wheeler County shows the smallest lateral spacing and plenty of room for additional wells (Figure 33 and Table 6). HF activities in the Cleveland and Marmaton Formations are focused on Hemphill, Lipscomb, and Ochiltree Counties (Figure 34 and Figure 35). Combining information from the three plays illustrates that the county with the smallest average lateral spacing (Lipscomb County) still allows for significant development at ~11,000 ft (Figure 36), as illustrated in Figure 37.

III-1-6 East Texas Basin

The East Texas Basin contains many formations susceptible to being hydraulically fractured. This section focuses on the Cotton Valley Fm., but, as was done for the Permian Basin and the Gulf Coast Basin, all water use data from wells in formations that were not part of the plays targeted for detailed study were still added to the total water use.

The Cotton Valley Fm. has been producing for decades and has been subjected to HF for almost as long. However, as observed in the rest of the state, there is a general shift from vertical to horizontal wells. Annual completions of vertical wells have been decreasing from ~1500 wells per year in 2007 to ~300 in 2011 (Figure 38a), whereas horizontal wells have been increasing from almost none in 2005 to ~100 in 2011 (Figure 39a). Total water use has followed the same path from ~1.5 kAF/yr to ~0 and from ~0 to 0.6 kAF/yr, respectively (Figure 38b and Figure 39b). In 5 years, the length of lateral has increased from ~1,000 ft to ~4,000 ft in 2011 (Figure 39c) with the associated water use increase to 4 million gallons per well in 2011 (Figure 39d). In the same period, water intensity has stayed steady at ~1,000 gal/ft (Figure 39e) and proppant loading has remained at ~0.8 lb/gal (Figure 39f). The overall representivity of the usable data set is at a steady ~70% for the horizontal wells but decreasing to only 25% for the vertical wells. A water intensity vs. depth cross-plot (Figure 40) displays no obvious trends but maps of well density (Figure 41 and Figure 42) show that horizontal wells are being completed in the same areas as where the vertical wells were drilled and that there is a good overlap of the high density values.

III-1-7 Gulf Coast Texas

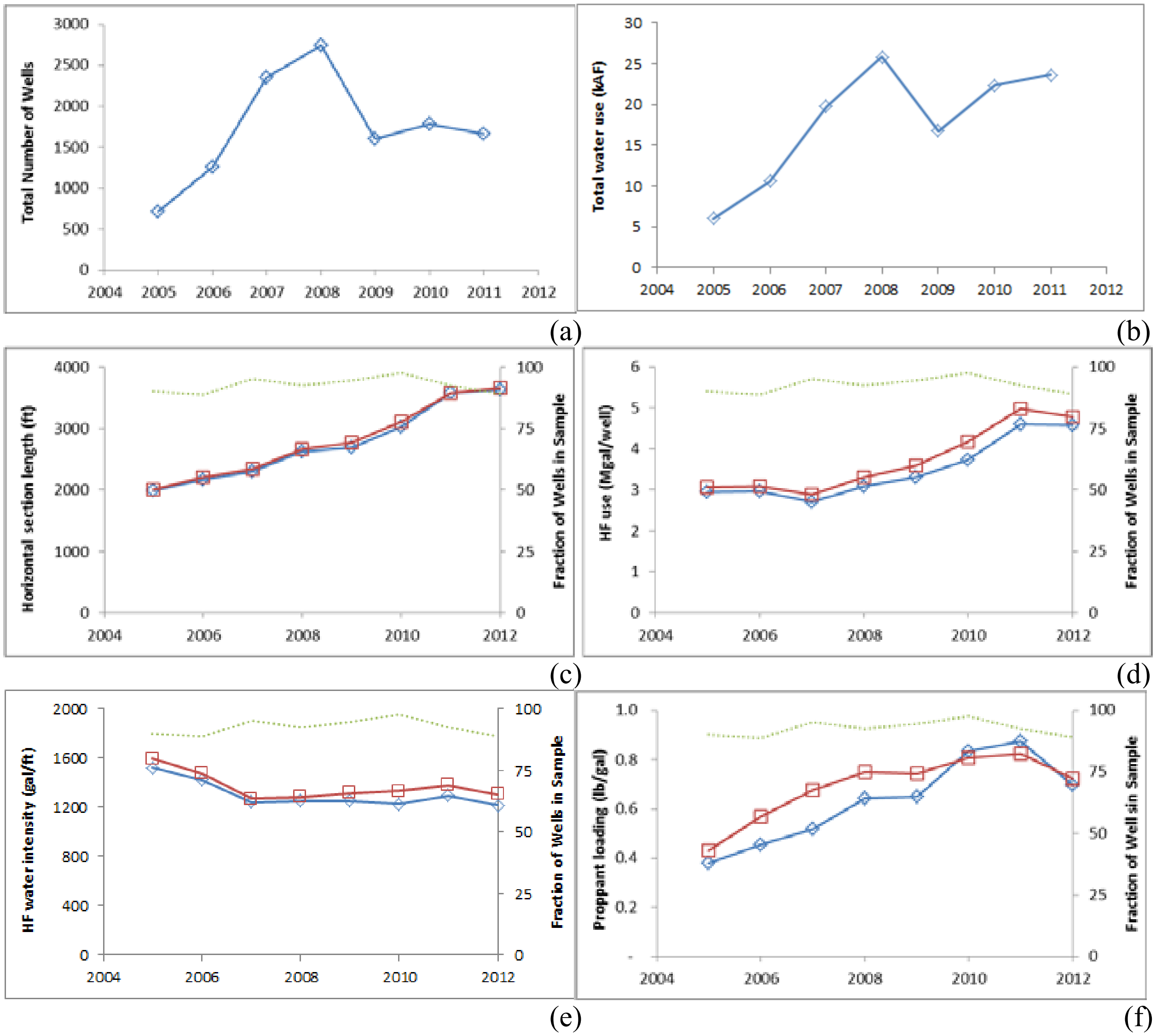
Similarly to the Permian Basin and the East Texas Basin, the Gulf Coast Basin, which includes many counties from the Mexican border to the Louisiana state line, contains several formations amenable to being hydraulically fractured. Each of these formations is not described here (for example, the Austin Chalk), but their water use is included in the total reported below. In this section, we document the Olmos Sands, where HF is taking place through horizontal wells. The annual number of completion is still low at 70 completions a year (Figure 43a) but growing and the total water use displays the same growth (~0.5 kAF in 2011, Figure 43b). Average lateral length has reached ~4,000 ft in 2011 (Figure 43c), and the average water use per well has increased to 4 million gal/well (Figure 43d). Although irregular through the years, water intensity has reached a value of ~1,000 gal/ft (Figure 43e) consistent with what has been observed elsewhere.

Table 2. Percentage of wells in each play or region that yielded a complete and consistent data set (water, proppant, length) from year 2011.

Play / Region	Percent
Barnett	92.7%
Eagle Ford	46.9%
Haynesville	31.8%
Cotton Valley	31.4%
Anadarko	69.4%
Permian Basin	84.9%

ResultsSummary_year2011.xlsx

Barnett Shale:



Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 4. Barnett Shale horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Barnett Shale:

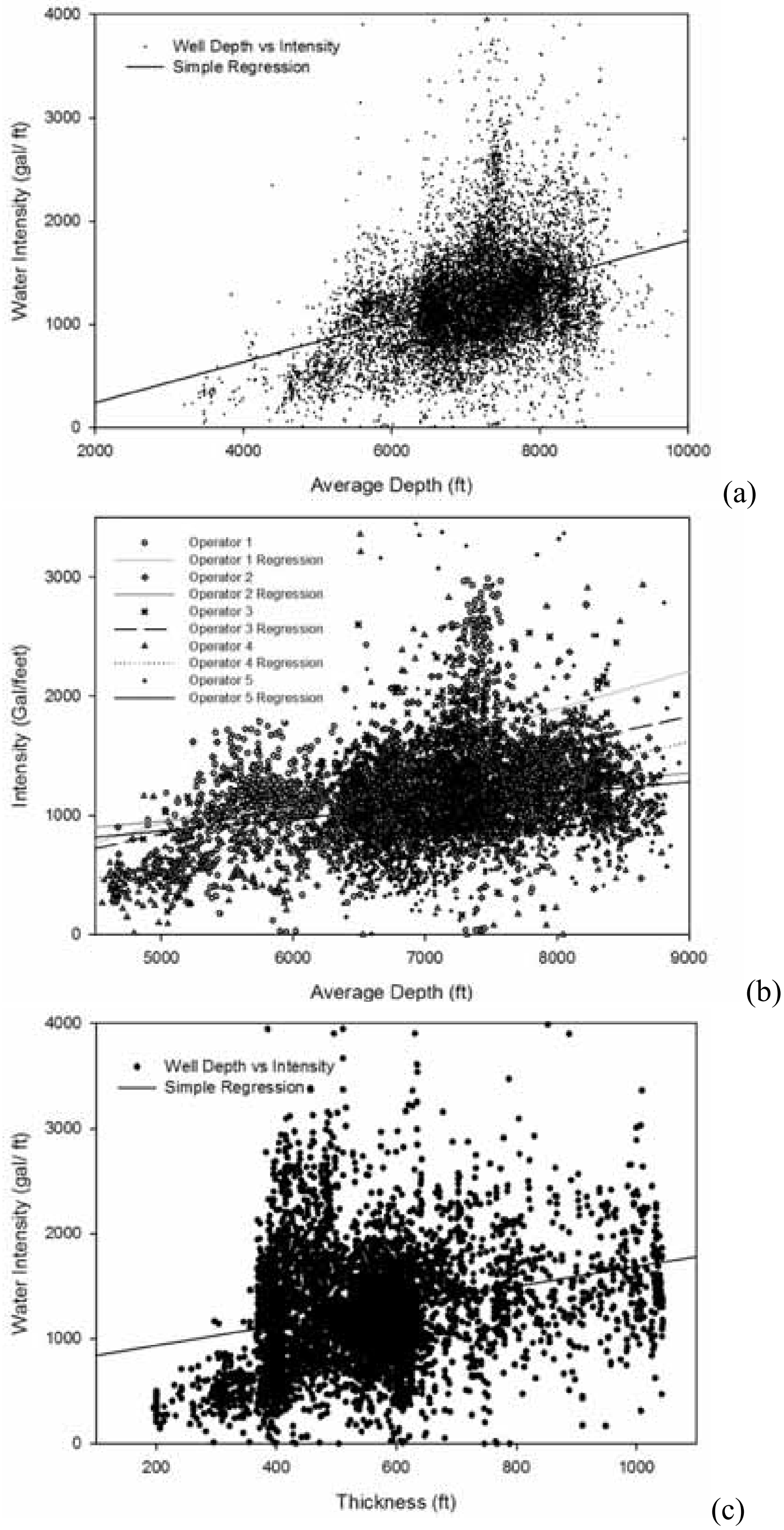
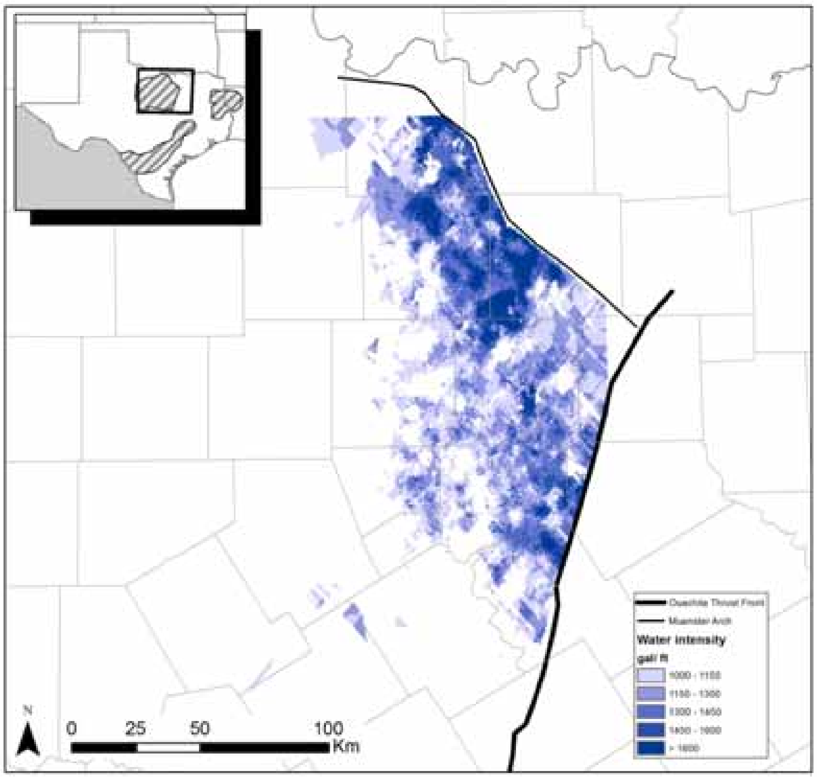
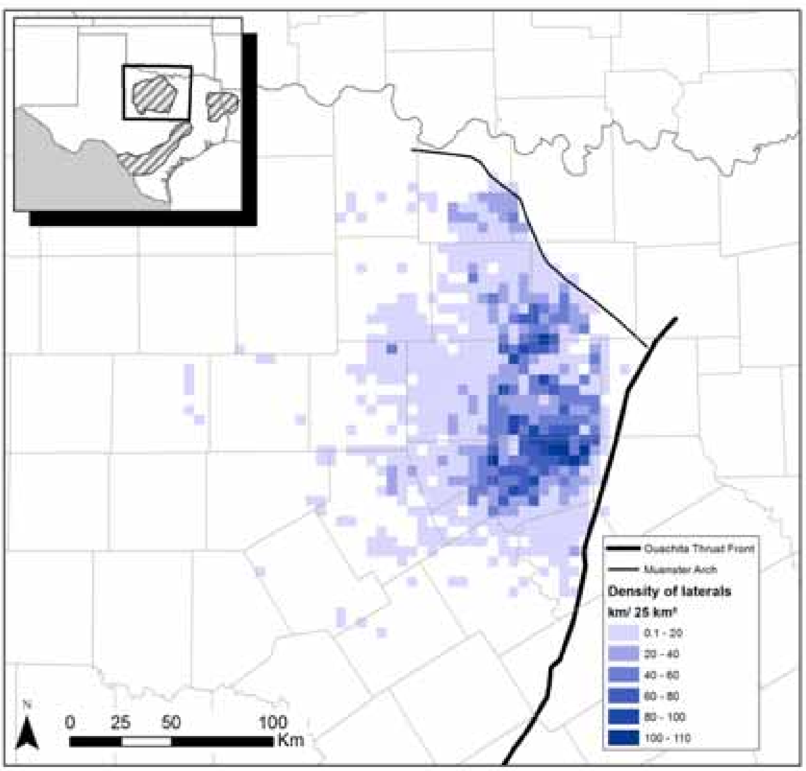


Figure 5. Barnett Shale horizontal water use intensity as a function of (a) depth; (b) operator and depth; and (c) formation thickness.

Barnett Shale:



(a)



(b)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 6. Barnett Shale spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

Barnett Shale:

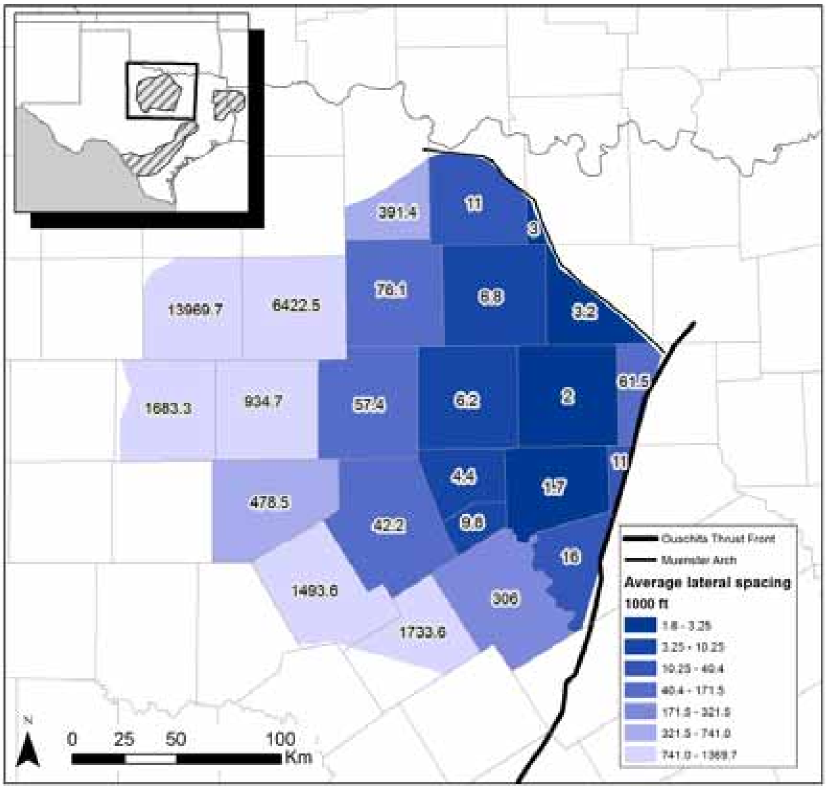


Figure 7. Barnett Shale county-level average lateral spacing.

Table 3. Barnett Shale county-level average lateral spacing for top producing counties.

County Name	Sum lateral length / county area (km/km^2)	Average Lateral Spacing (1000 ft)
Johnson	1.94	1.69
Tarrant	1.66	1.98
Hood	0.75	4.35
Parker	0.53	6.20
Wise	0.48	6.77
Denton	0.47	6.99
Somervell	0.34	9.76
Others		>10×10^3 ft

Note: Average spacing = 1/ (lateral length density);
Counties are sorted by decreasing lateral length density

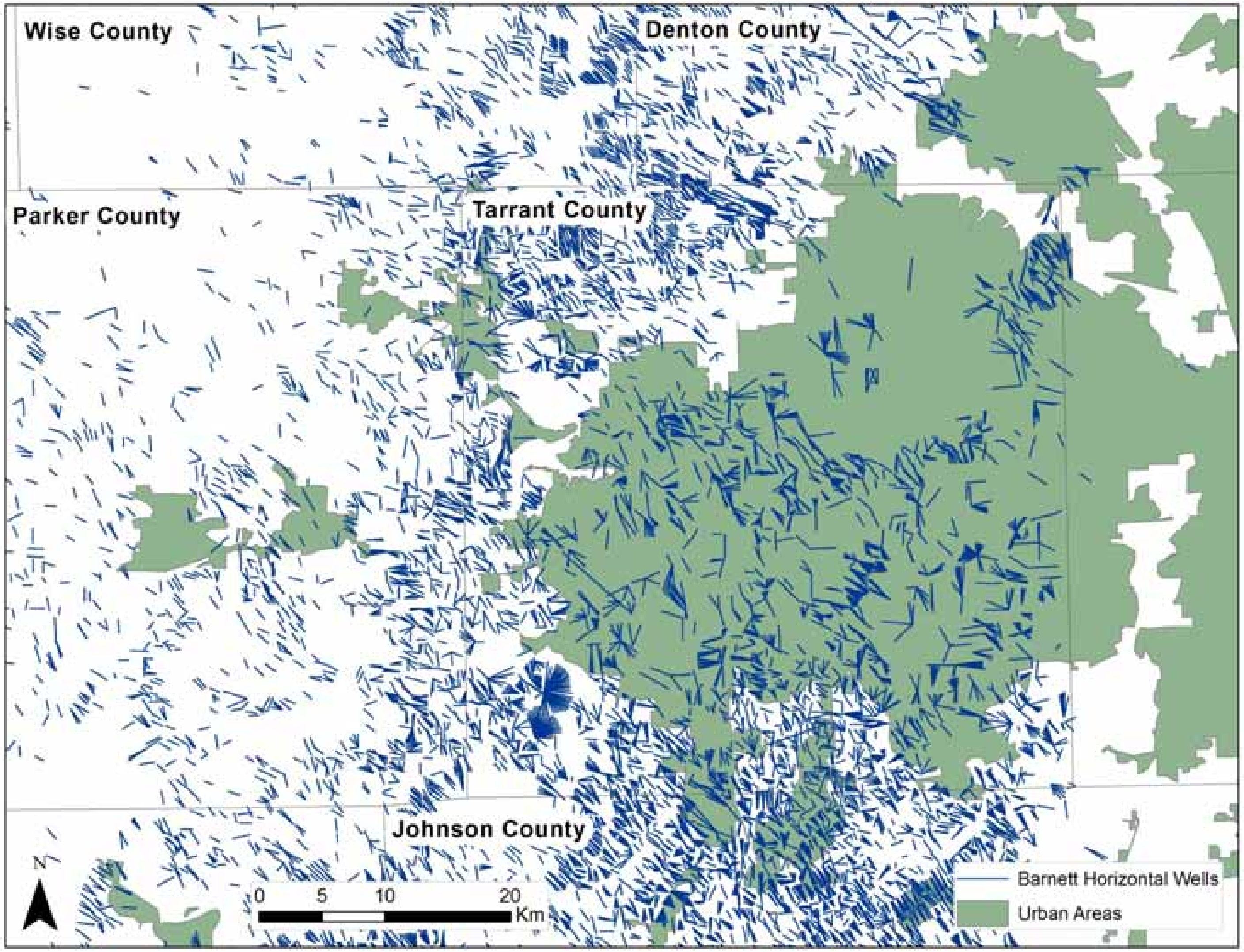
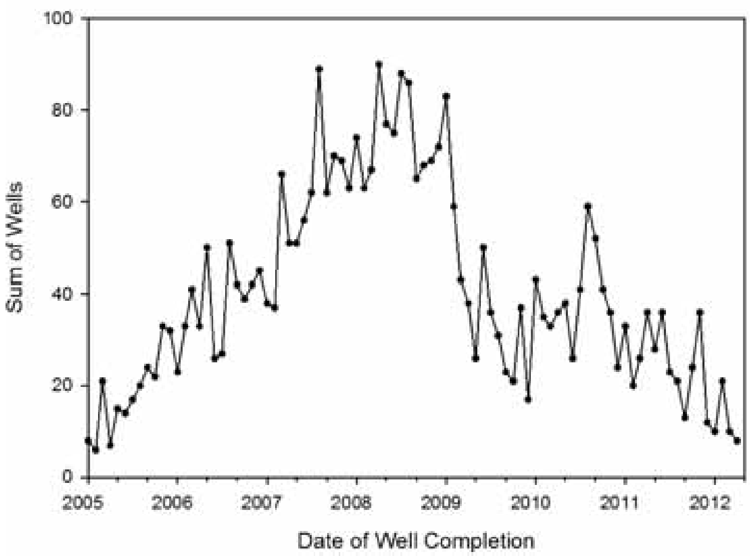
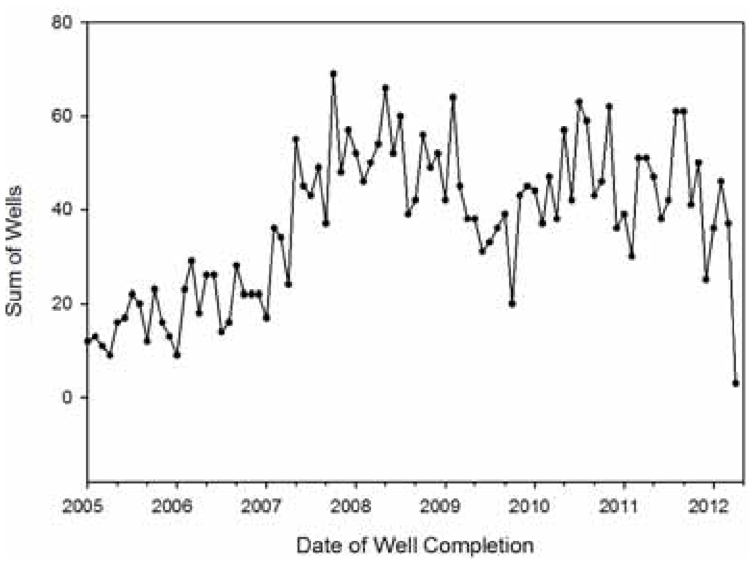


Figure 8. Map view of lateral expression of horizontal wells in the Barnett Shale centered on Tarrant County.



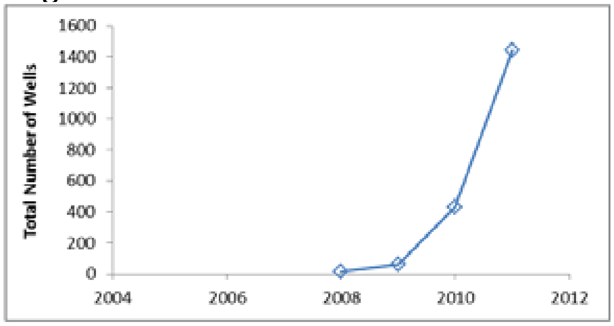
(a)

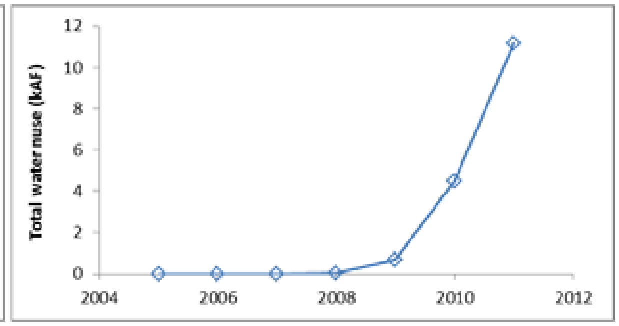


(b)

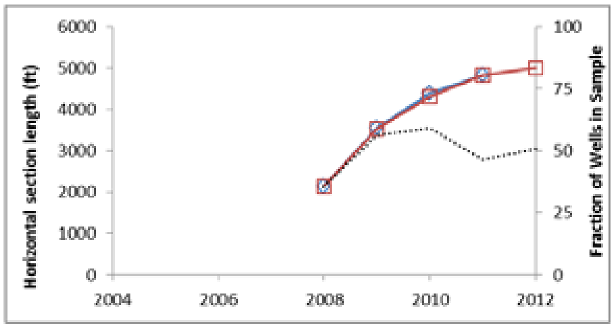
Figure 9. Annual well count in Johnson (a) and Tarrant (b) counties.

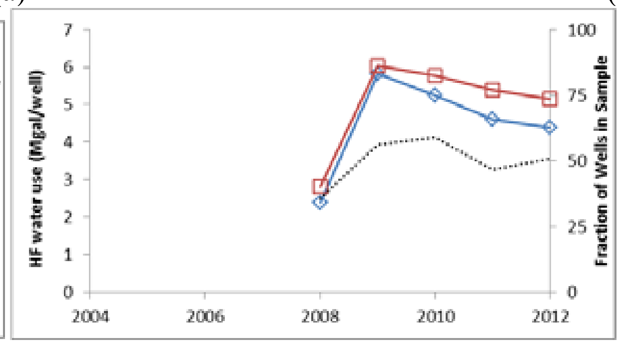
Eagle Ford Shale:



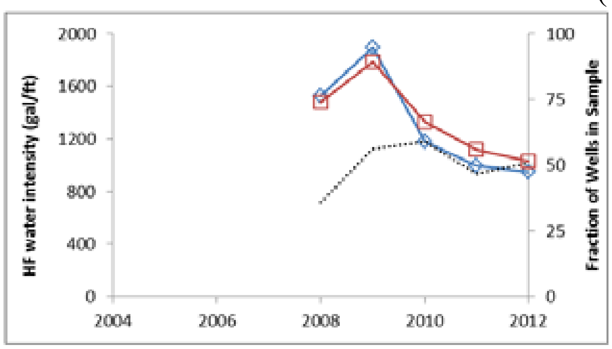


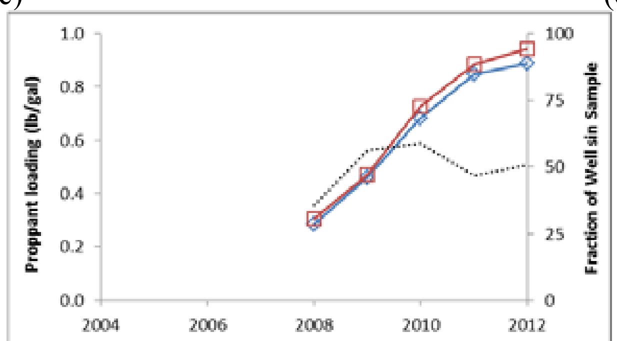
(a) (b)





(c) (d)



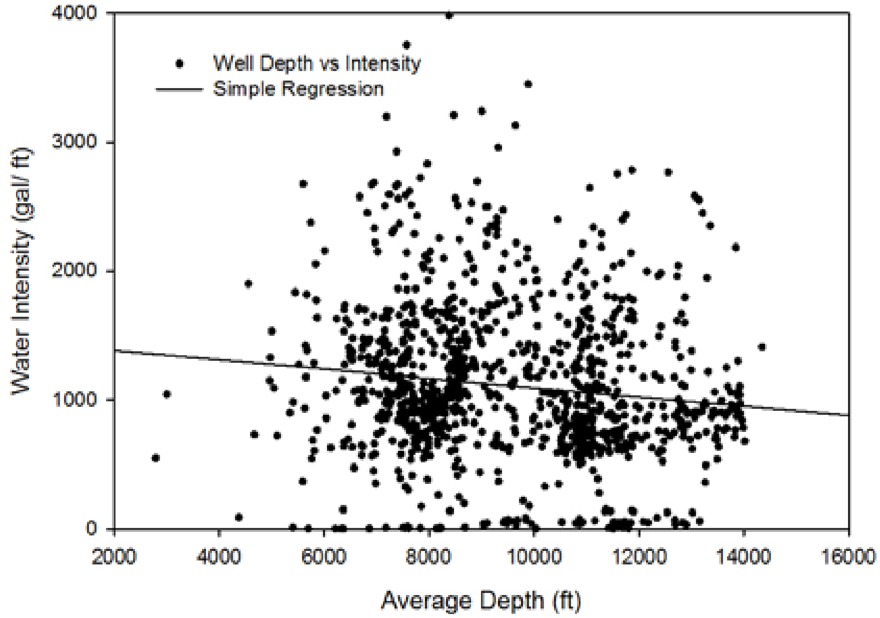


(e) (f)

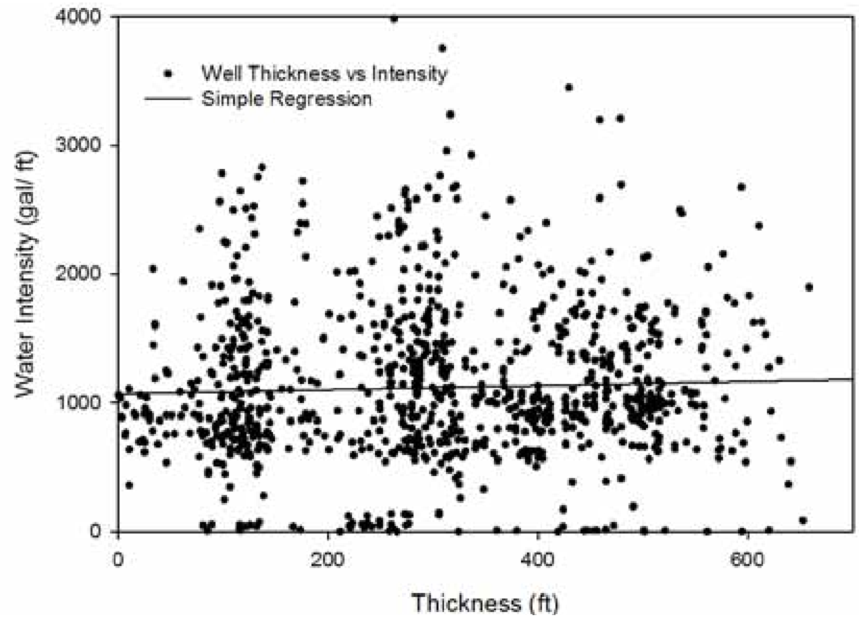
Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 10. Eagle Ford horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Eagle Ford Shale:



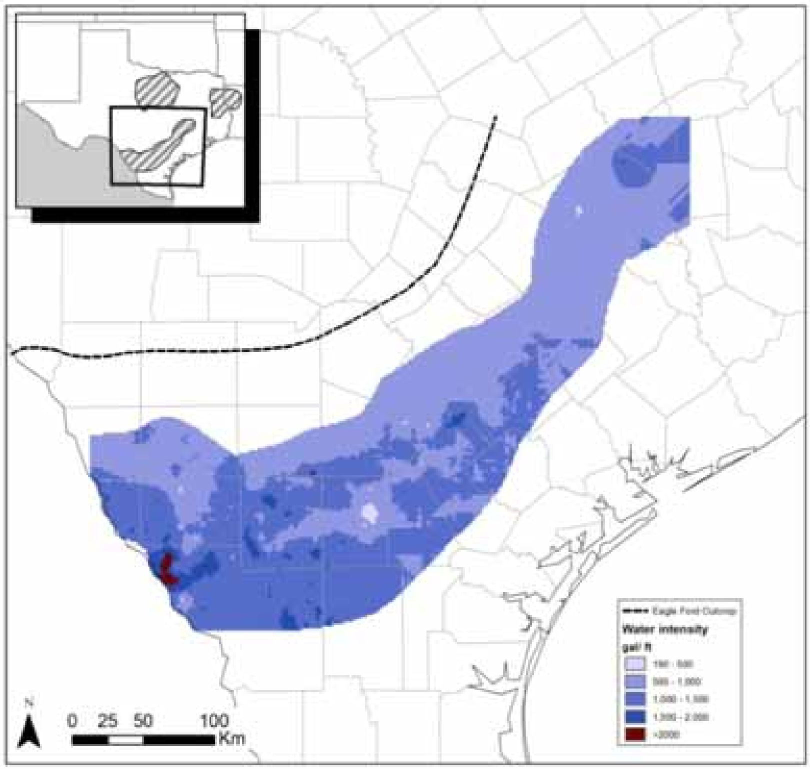
(a)



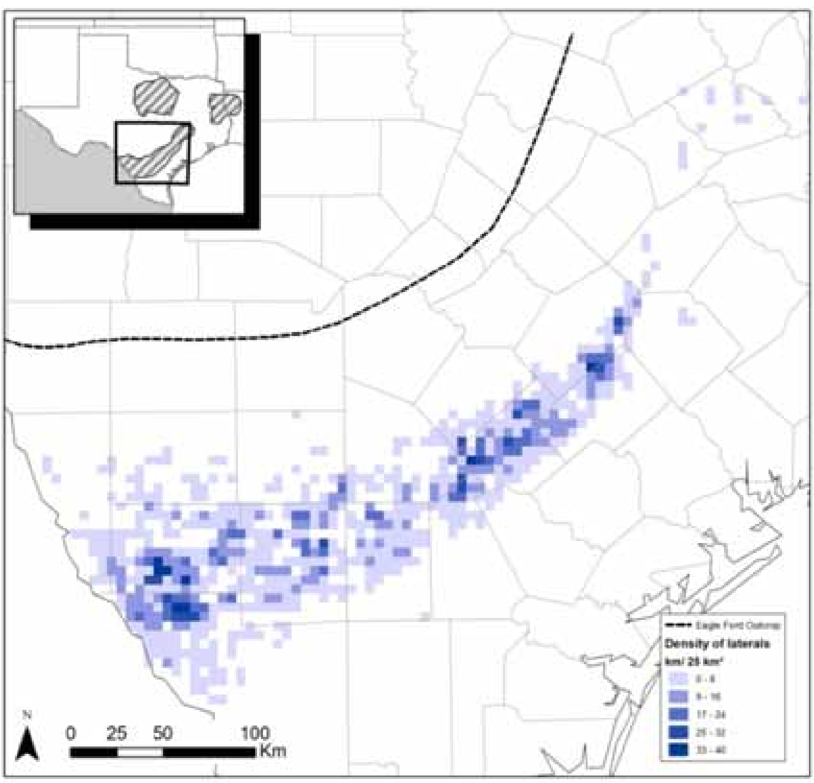
(b)

Figure 11. Eagle Ford Shale horizontal wells' water use intensity as a function of (a) depth; and (b) formation thickness.

Eagle Ford Shale:



(a)



(b)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 12. Eagle Ford Shale spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

Eagle Ford Shale:

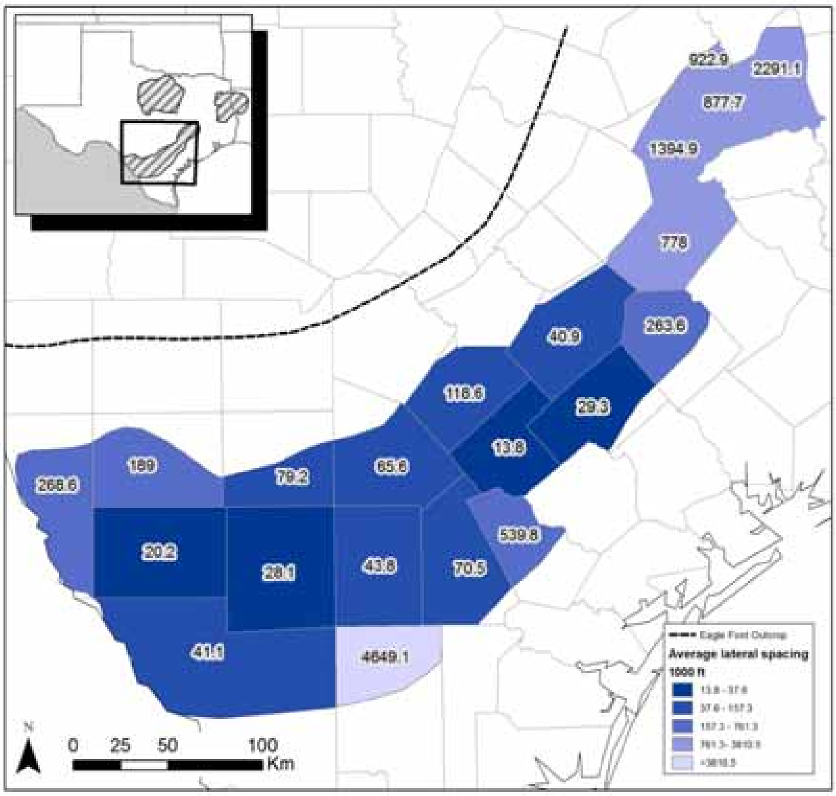
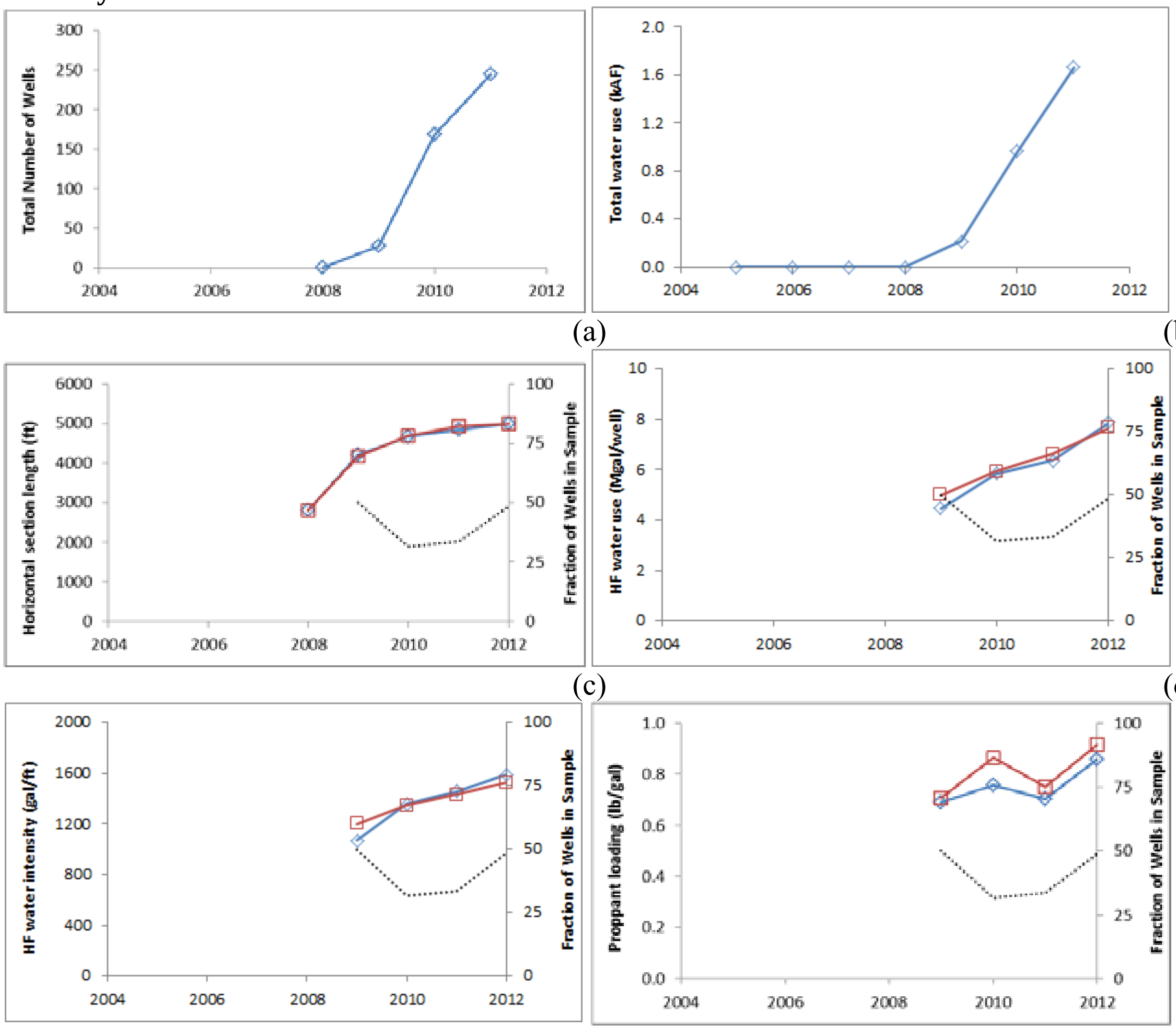


Figure 13. Eagle Ford Shale county-level average lateral spacing.

Table 4. Eagle Ford Shale county-level average lateral spacing for top producing counties.

County Name	Sum lateral length / county area (km/km^2)	Average Lateral Spacing (1000 ft)
Karnes	0.236	13.93
Dimmit	0.162	20.30
La Salle	0.116	28.20
De Witt	0.111	29.63
Gonzales	0.080	41.01
McMullen	0.075	43.79
Webb	0.080	41.11

TX-Haynesville Shale:

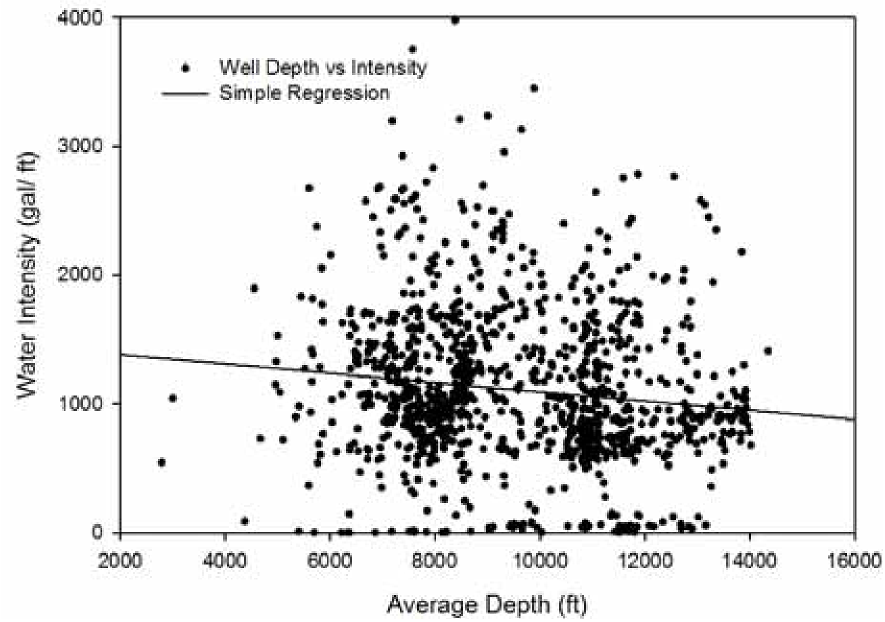


(a) (b) (c) (d) (e) (f)

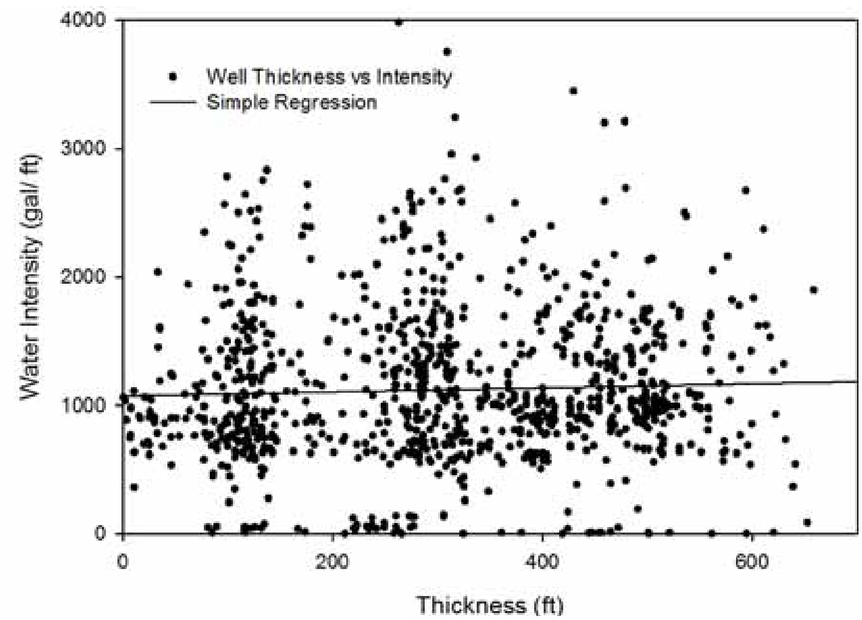
Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 14. TX-Haynesville Shale horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

TX-Haynesville Shale:



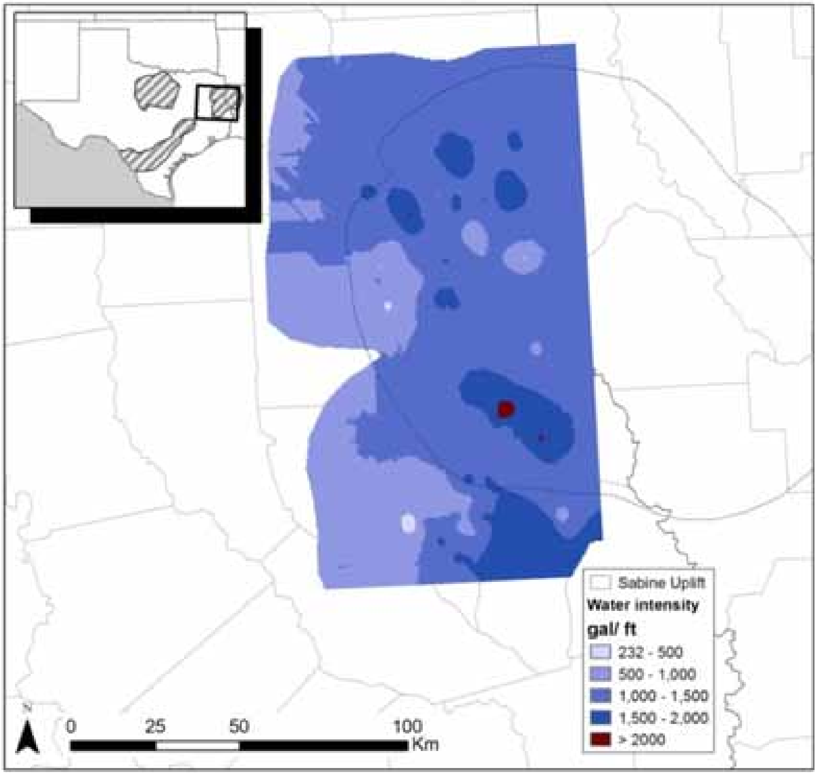
(a)



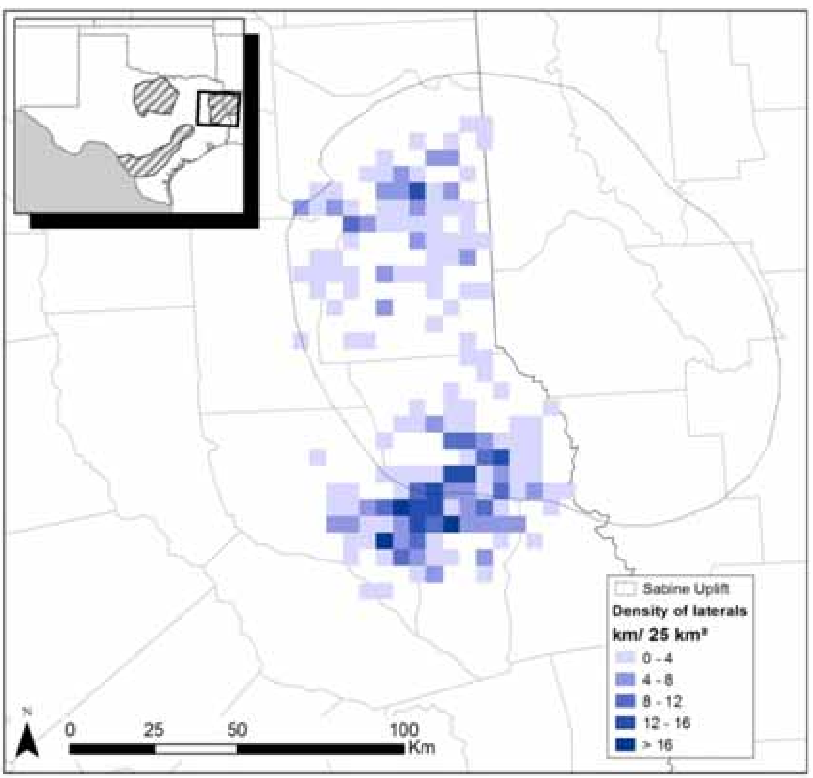
(b)

Figure 15. TX-Haynesville Shale horizontal water use intensity as a function of (a) depth; and (b) formation thickness.

TX-Haynesville Shale:



(a)



(b)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 16. TX-Haynesville Shale spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

TX-Haynesville Shale:

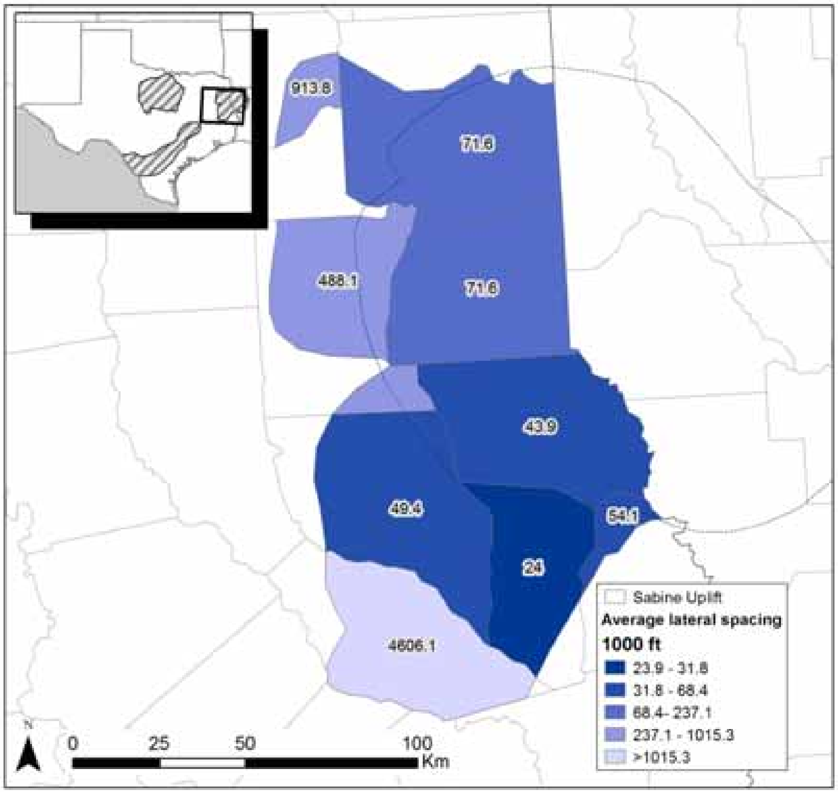
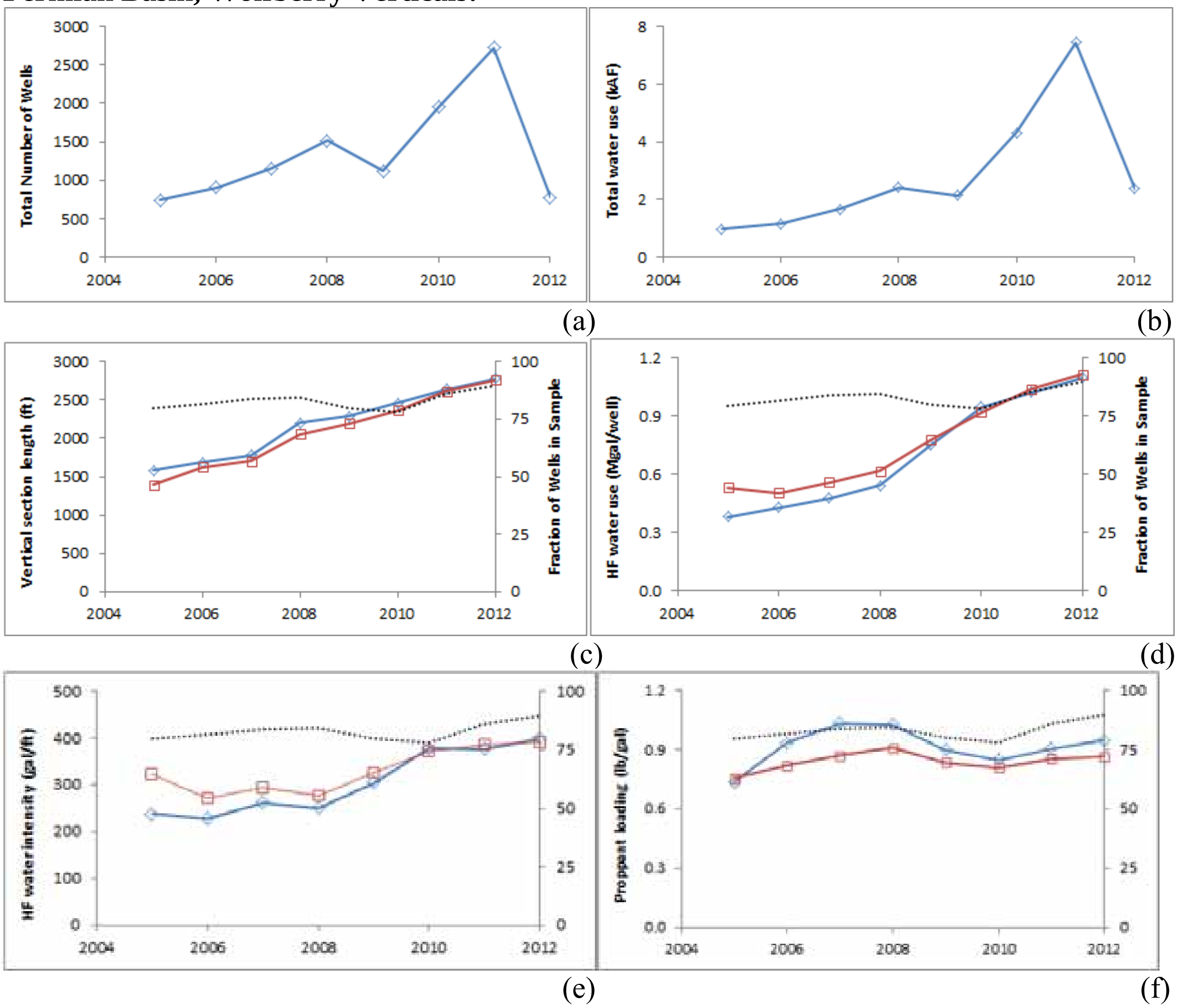


Figure 17. TX-Haynesville Shale county-level average lateral spacing.

Table 5. TX-Haynesville Shale county-level average lateral spacing for top producing counties.

County Name	Sum lateral length / county area (km/km^2)	Average Lateral Spacing (1000 ft)
San Augustine	0.137	23.97
Shelby	0.074	44.24
Nacogdoches	0.065	50.78
Sabine	0.061	54.11
Panola	0.046	72.03
Harrison	0.045	72.84

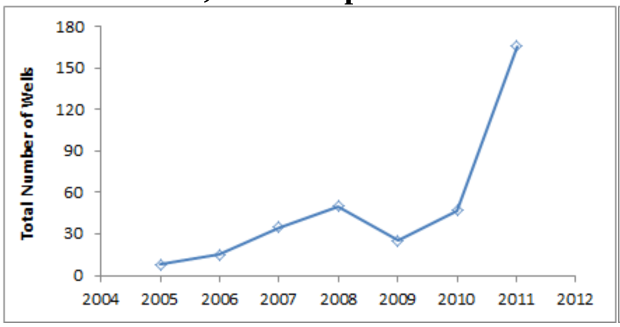
Permian Basin, Wolfberry Verticals:



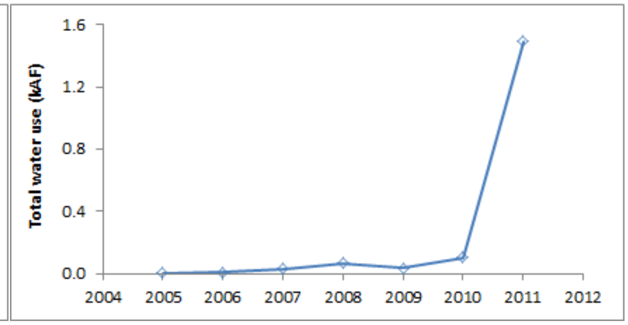
Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 18. Wolfberry verticals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median vertical productive section length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

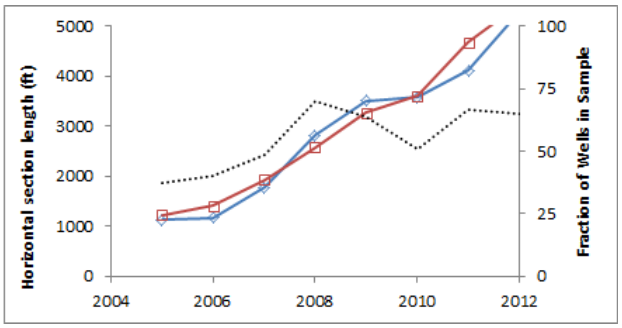
Permian Basin, Wolfcamp Horizontals:



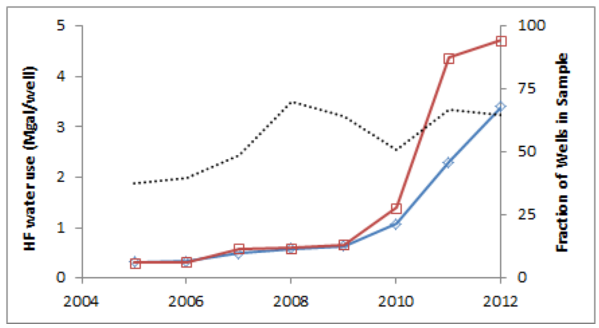
(a)



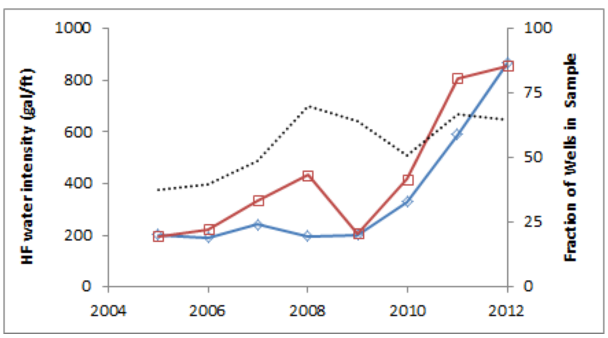
(b)



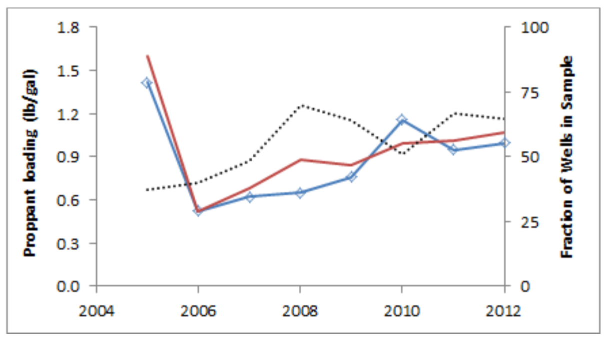
(c)



(d)



(e)

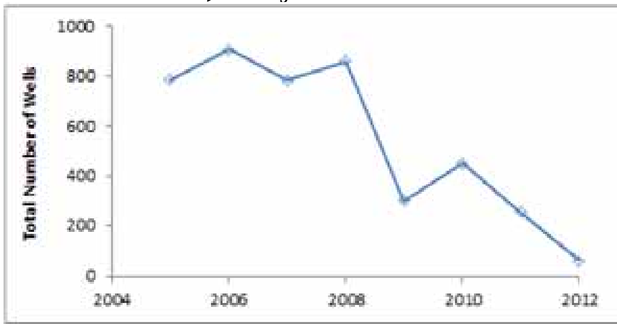


(f)

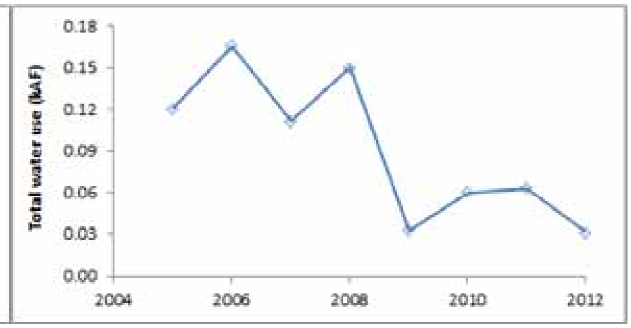
Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 19. Wolfcamp horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

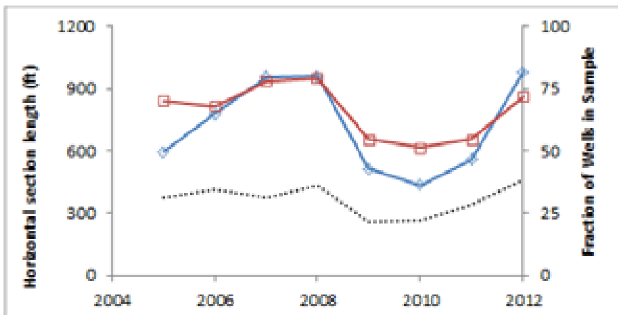
Permian Basin, Canyon – Horizontals:



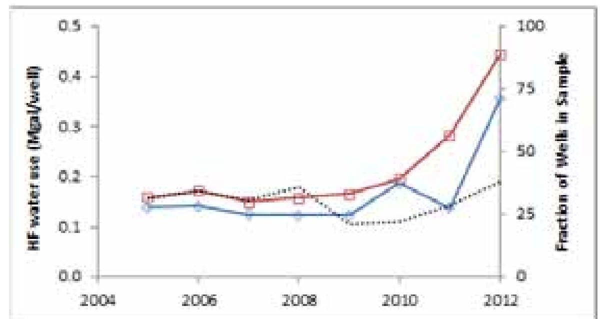
(a)



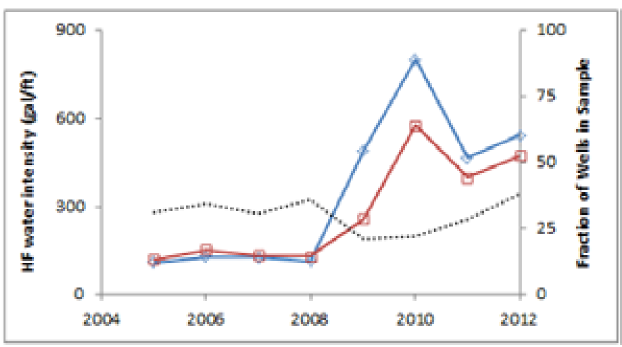
(b)



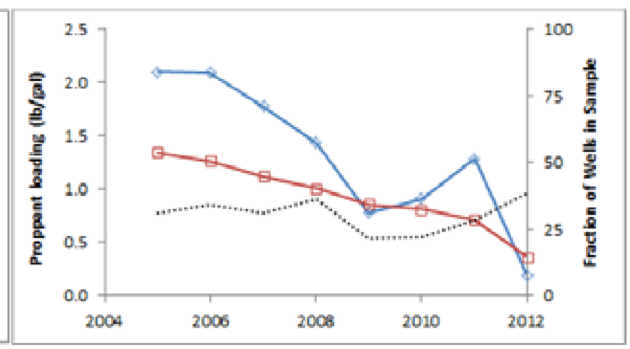
(c)



(d)



(e)

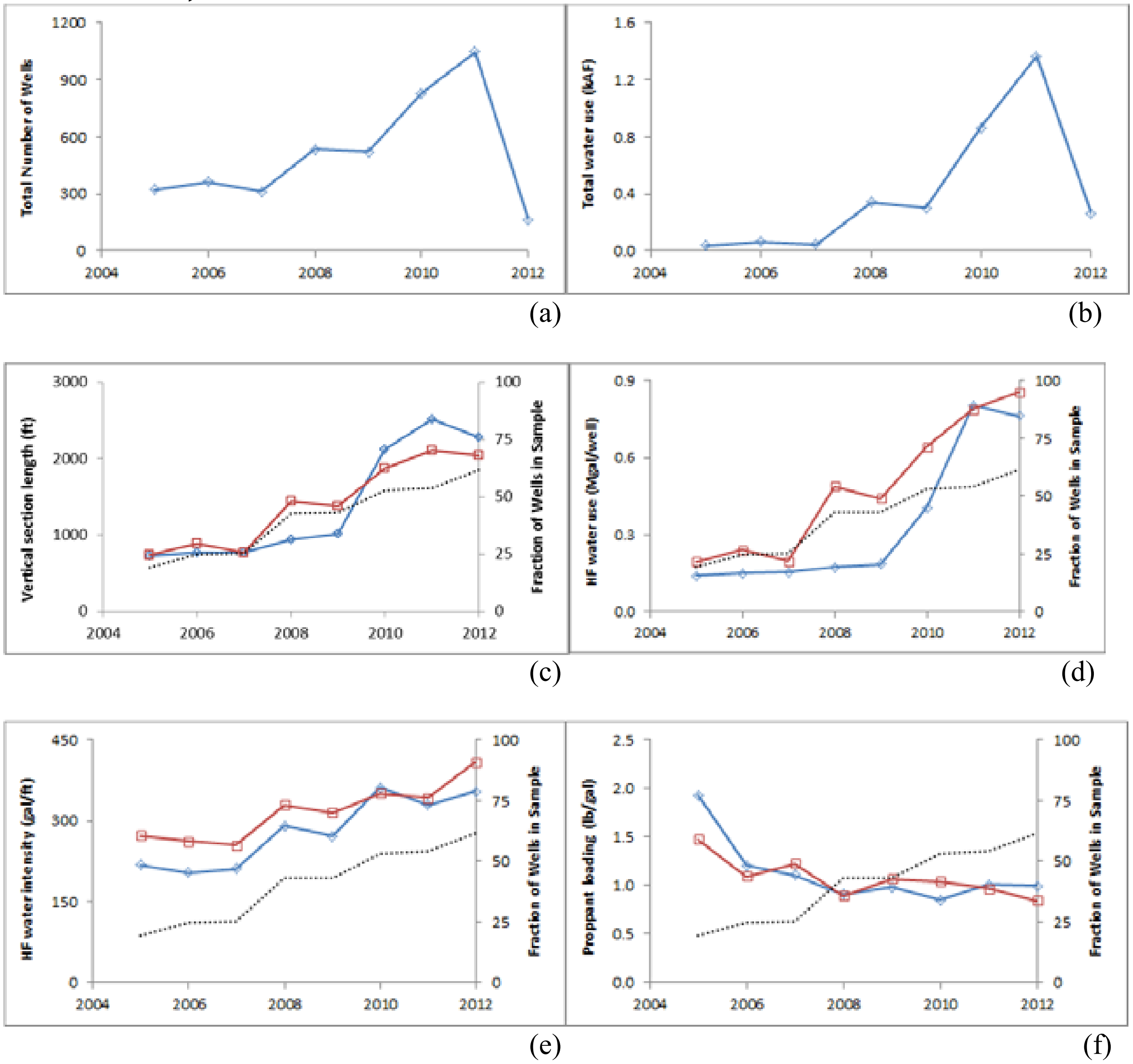


(f)

Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 20. Canyon Sand horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

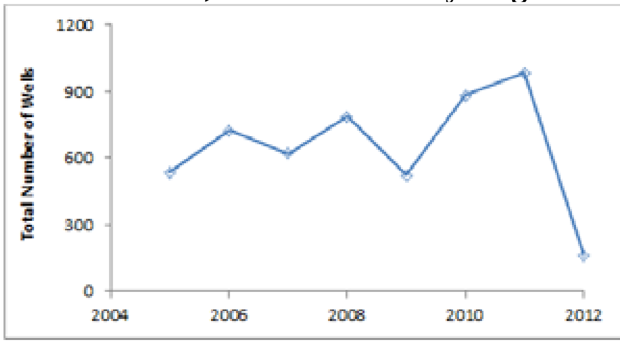
Permian Basin, Clearfork - Verticals

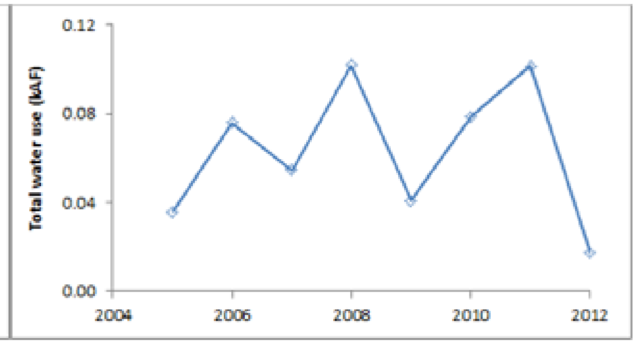


Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

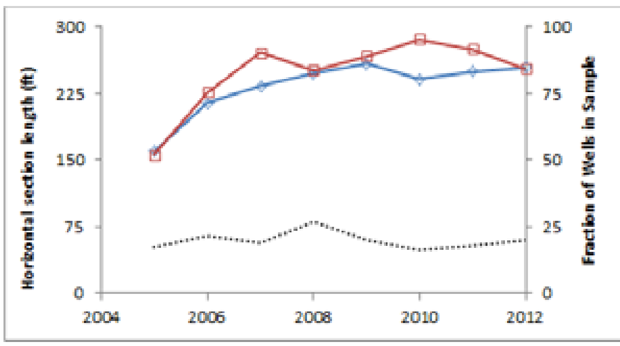
Figure 21. Clearfork verticals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median vertical productive section length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

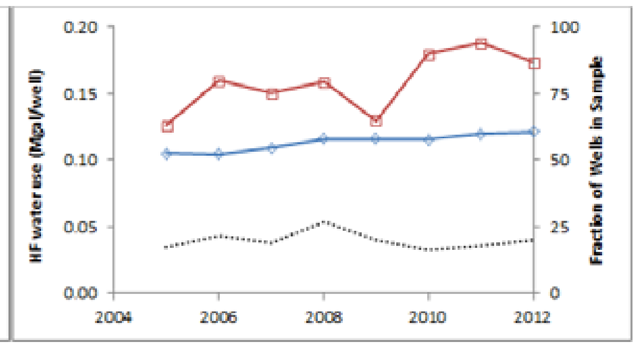
Permian Basin, San Andres-Grayburg -Verticals



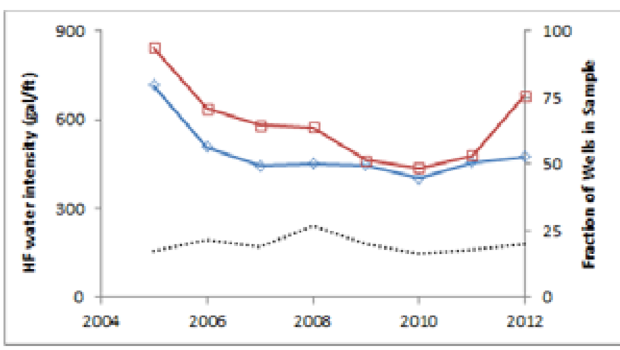


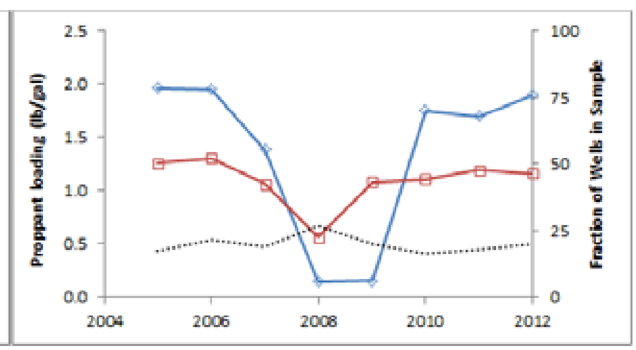
(a) (b)





(c) (d)



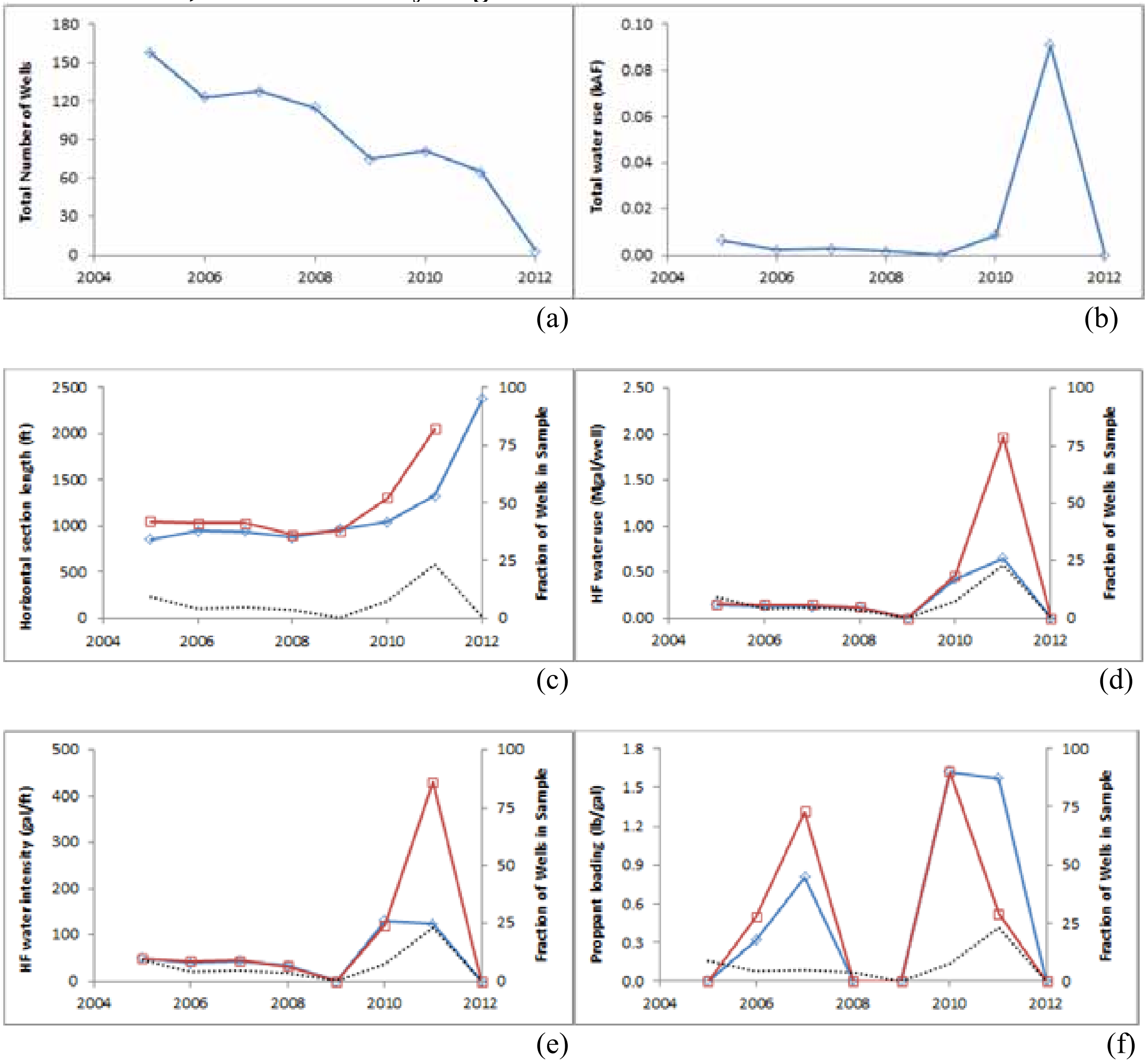


(e) (f)

Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 22. San Andres-Grayburg verticals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median vertical productive section length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

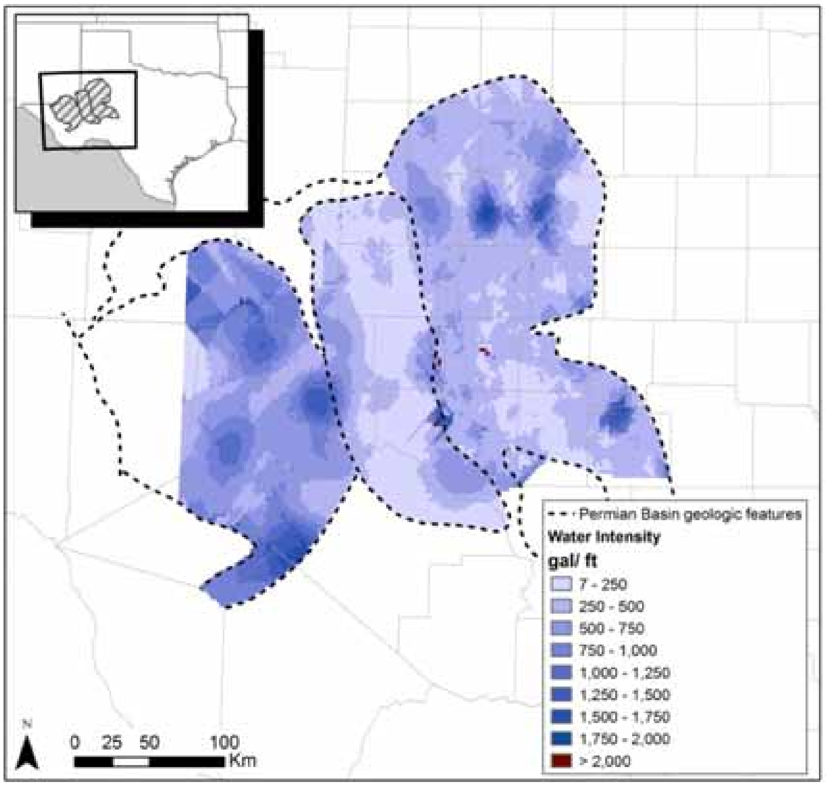
Permian Basin, San Andres-Grayburg -Horizontals



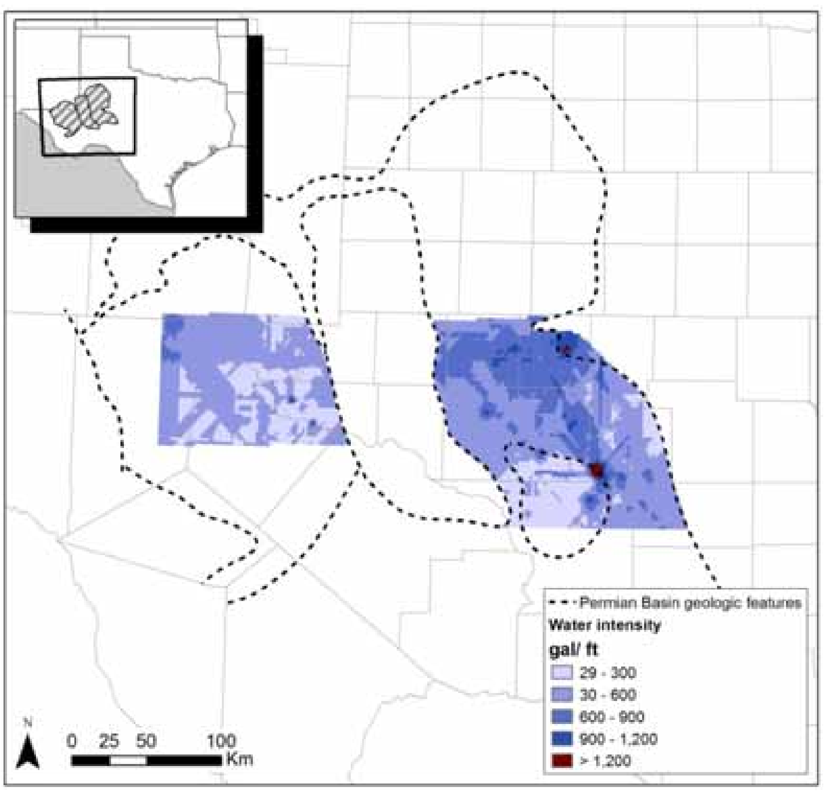
Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 23. San Andres-Grayburg horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Permian Basin:



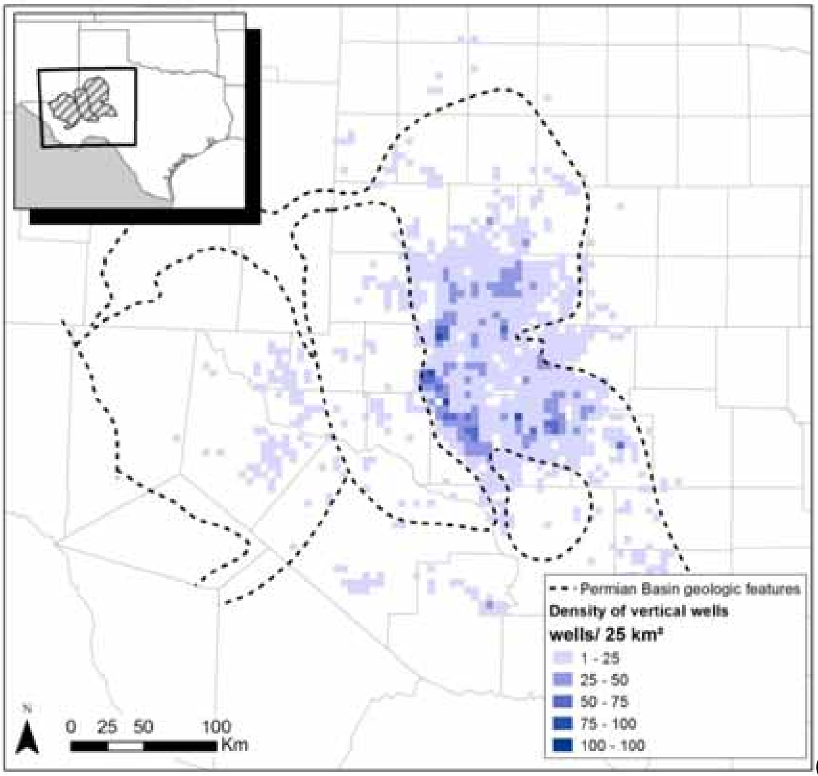
(a)



(b)

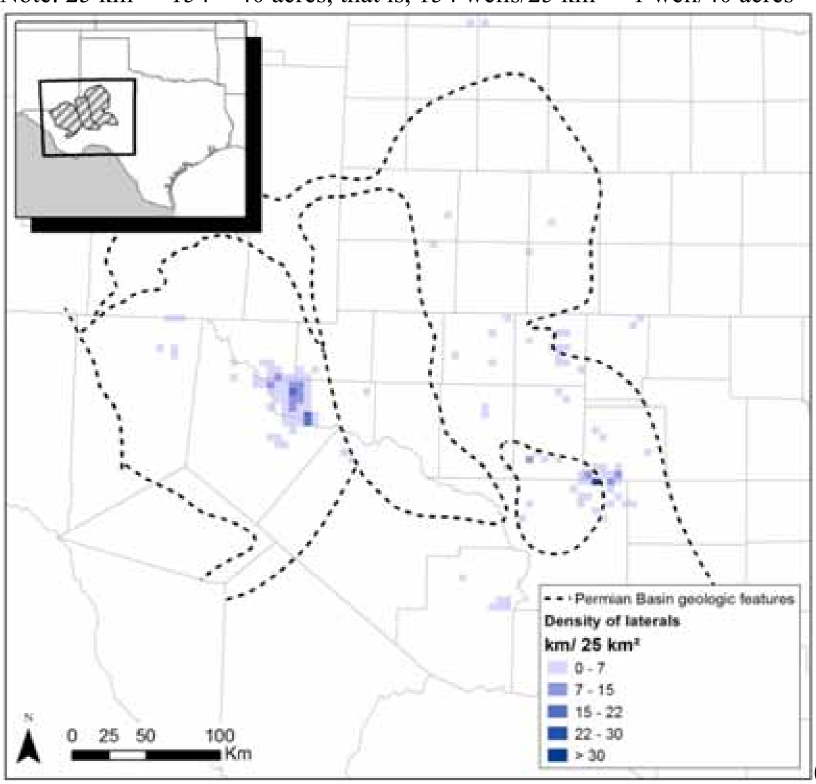
Figure 24. Permian Basin spatial distribution of water intensity for (a) vertical and (b) horizontal wells.

Permian Basin:



(a)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres



(b)

Figure 25. Permian Basin spatial distribution of (a) vertical well density and (b) density of lateral (cumulative length per area) for horizontal wells.

Permian Basin

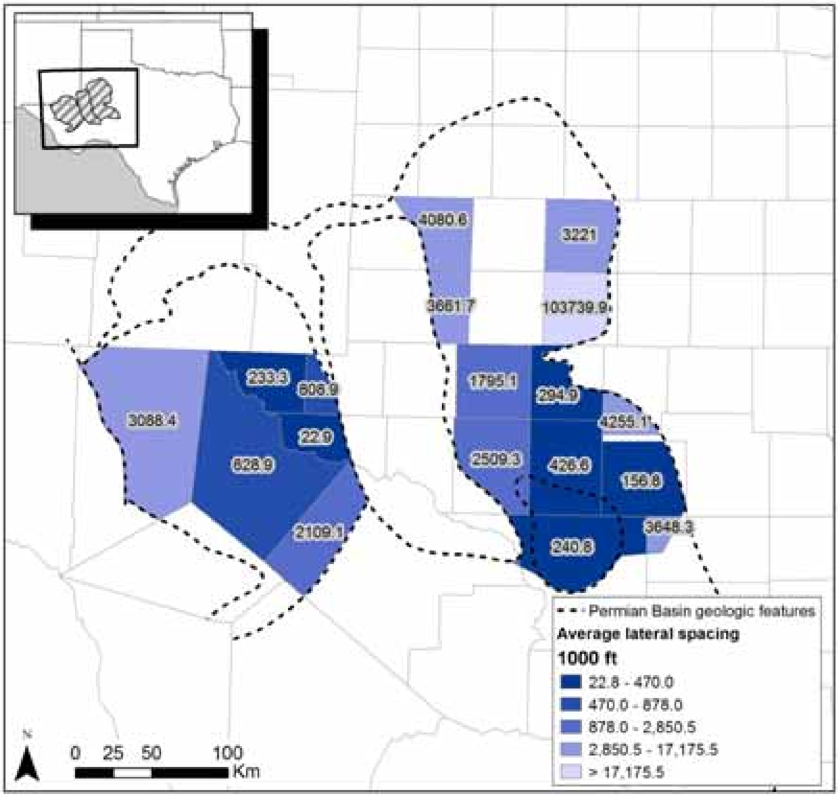
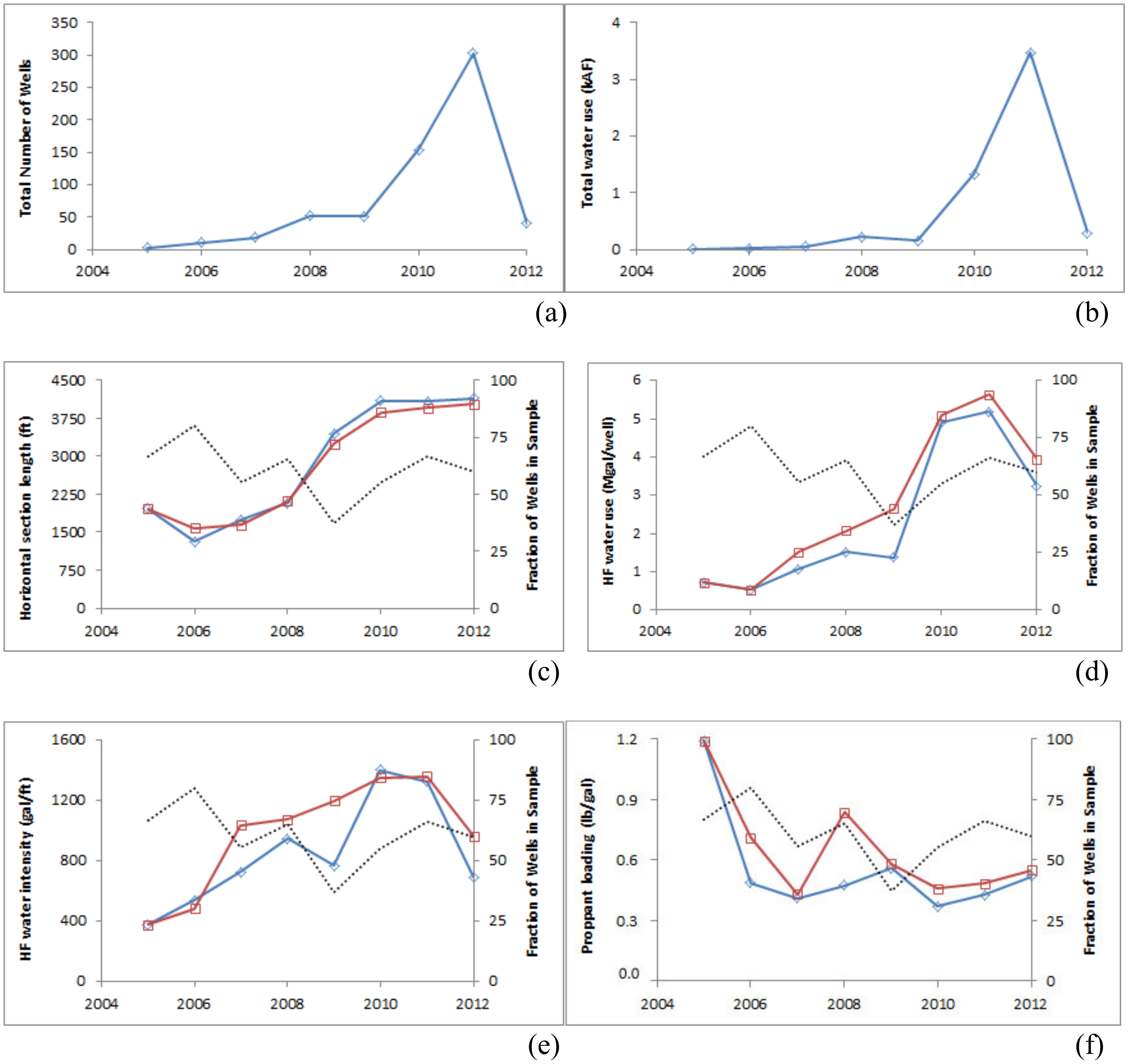


Figure 26. Permian Basin county-level average lateral spacing

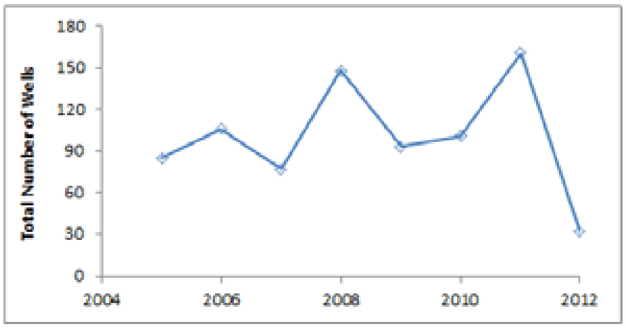
Anadarko Basin: Granite Wash Horizontals:



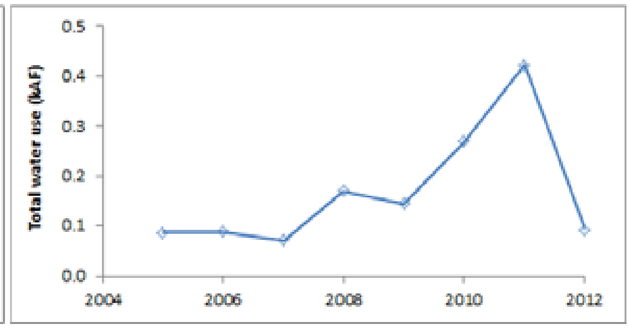
Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 27. Granite Wash horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

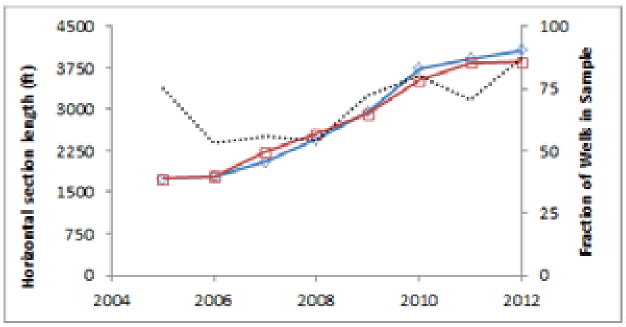
Anadarko Basin: Cleveland Horizontals:



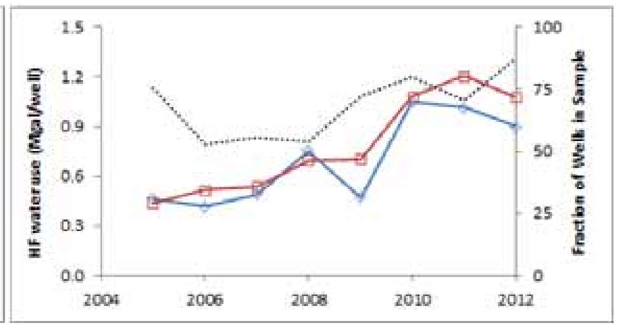
(a)



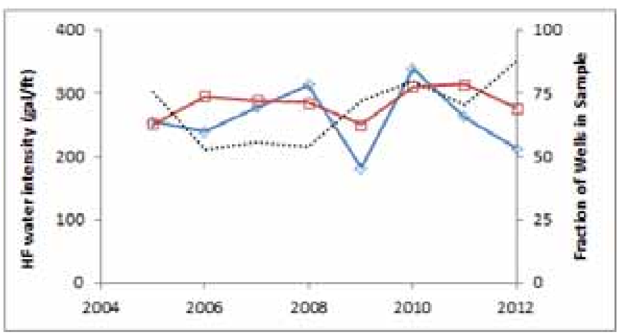
(b)



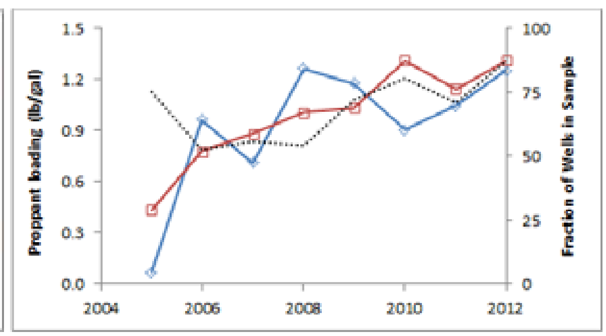
(c)



(d)



(e)

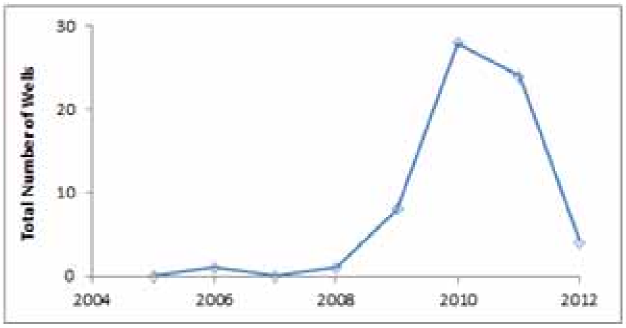


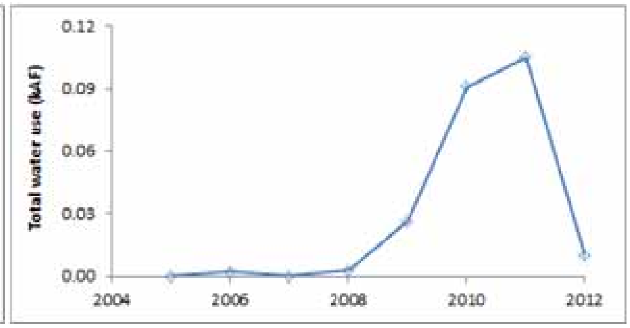
(f)

Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

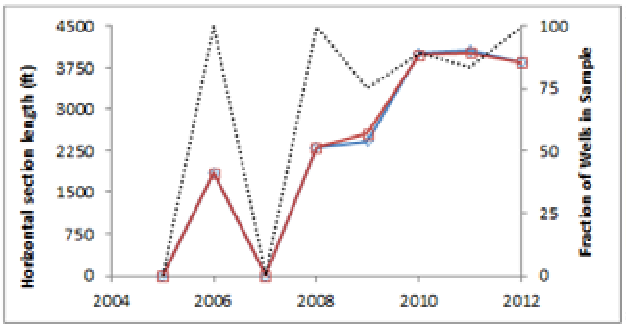
Figure 28. Cleveland horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

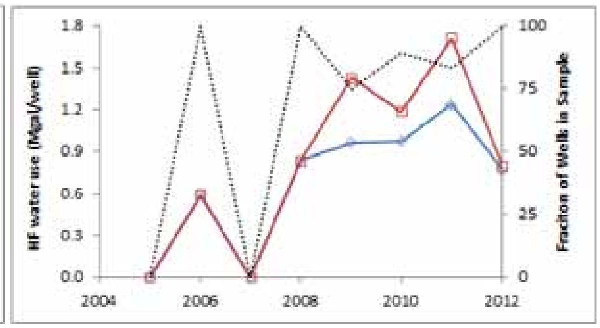
Anadarko Basin: Marmaton Horizontals:



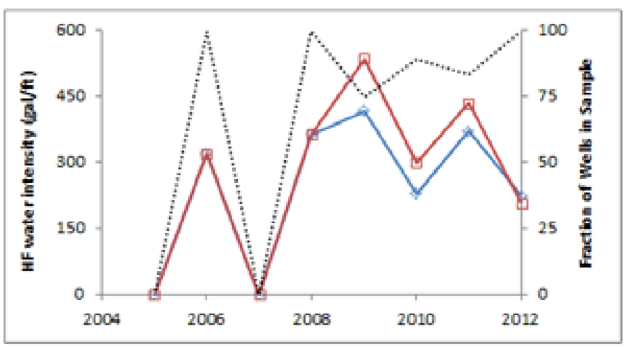


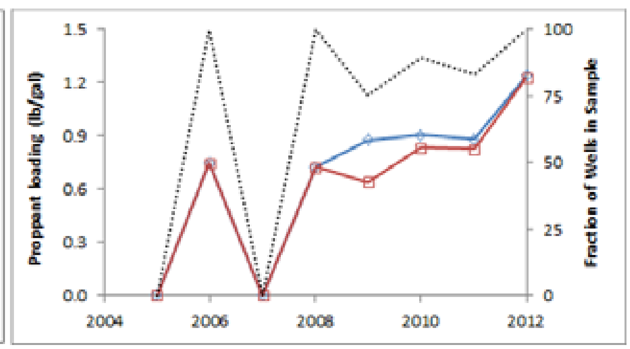
(a) (b)





(c) (d)





(e) (f)

Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 29. Marmaton horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

Anadarko Basin: Granite Wash Horizontals:

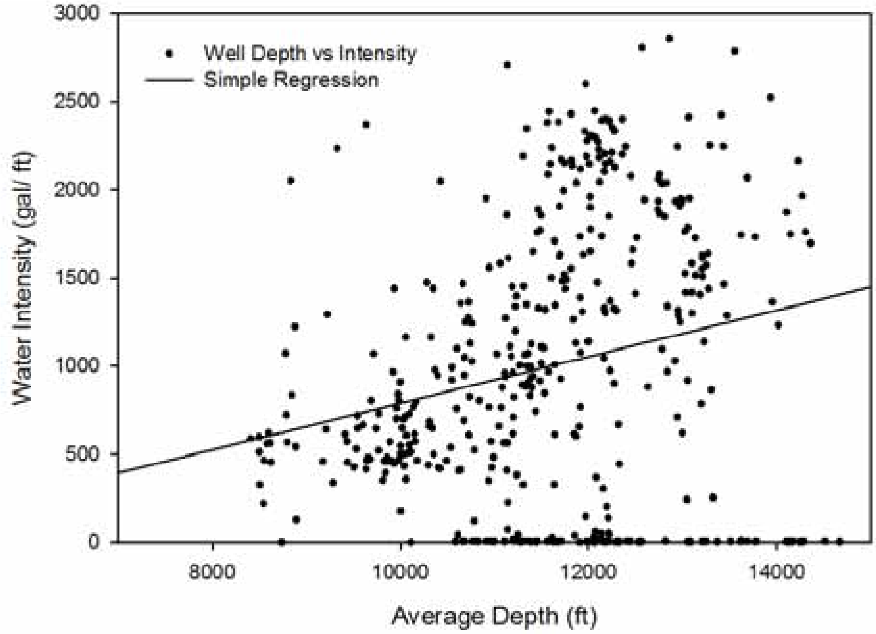


Figure 30. Granite Wash horizontal water use intensity as a function of depth.

Anadarko Basin: Cleveland Horizontals:

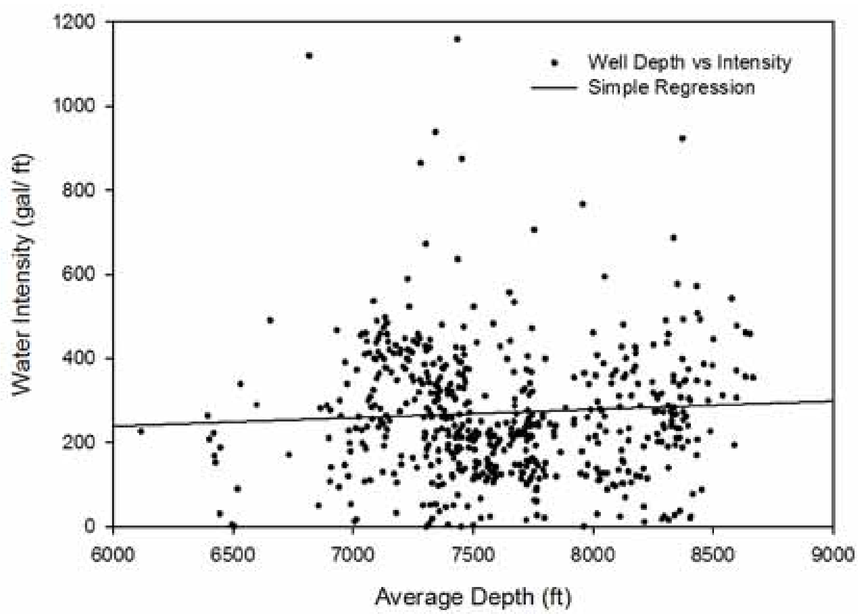
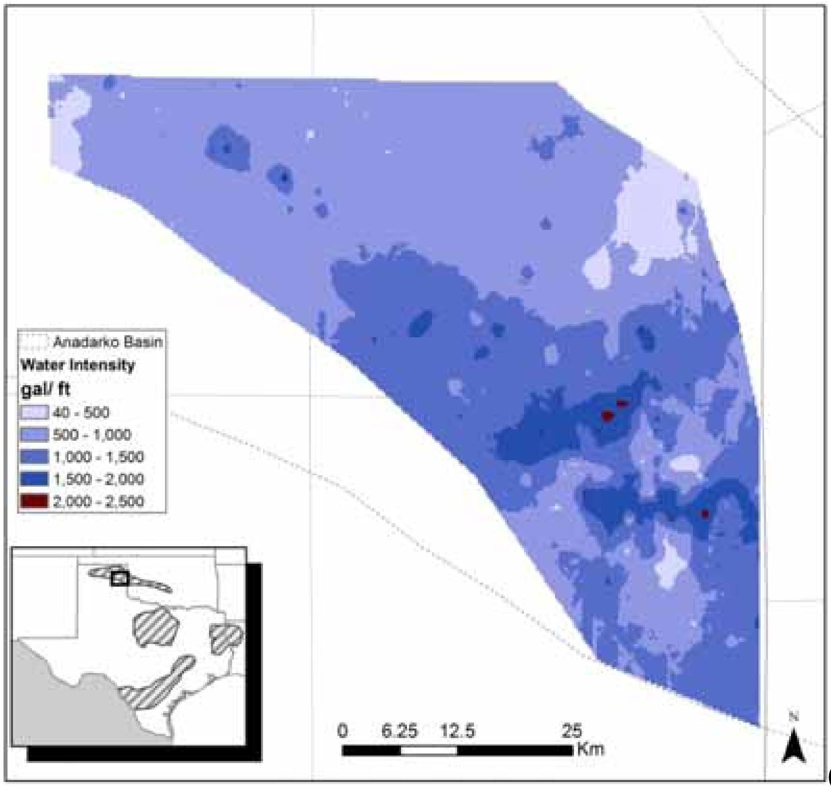
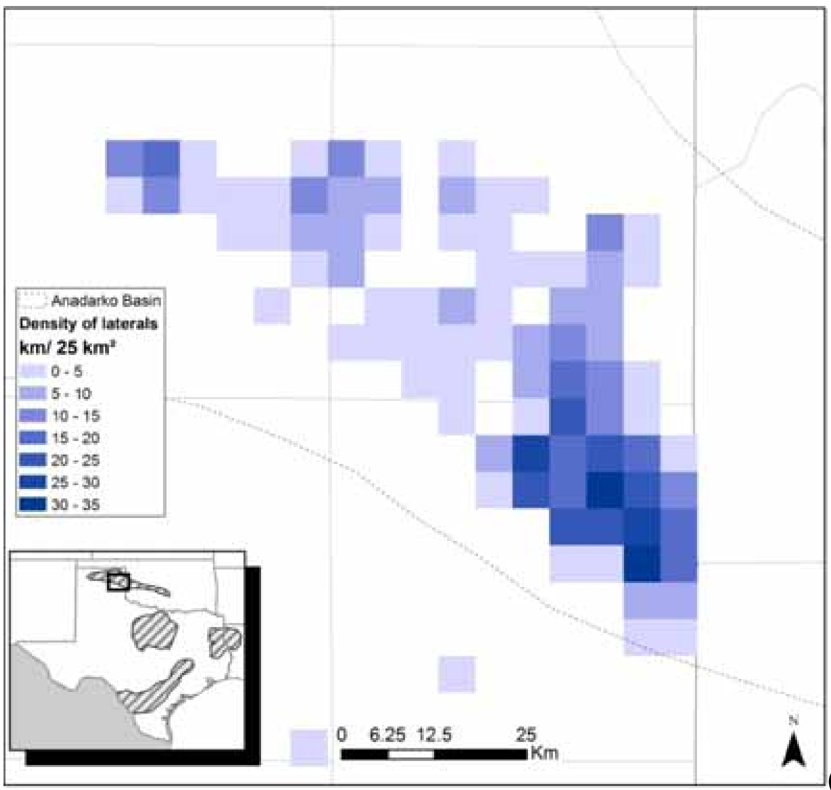


Figure 31. Cleveland horizontal water use intensity as a function of depth.

Anadarko Basin: Granite Wash Horizontals:



(a)



(b)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 32. Granite Wash spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

Anadarko Basin: Granite Wash Horizontals:

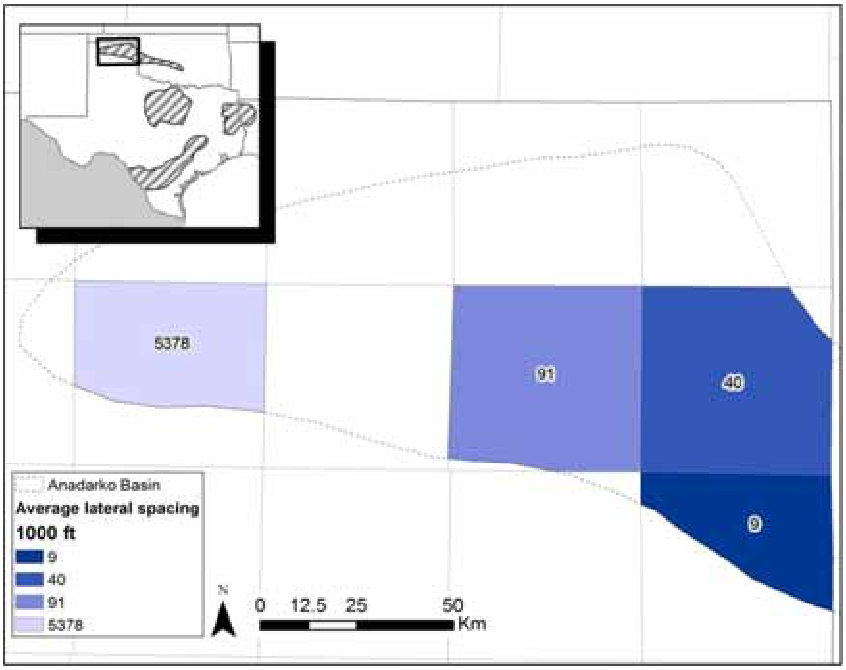
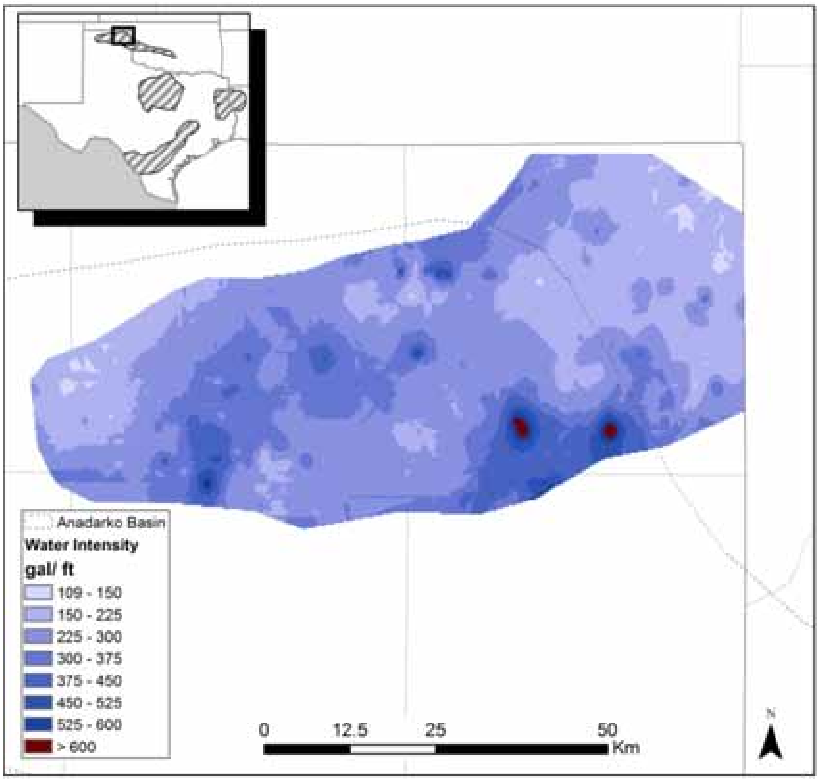


Figure 33. Granite Wash horizontals county-level average lateral spacing

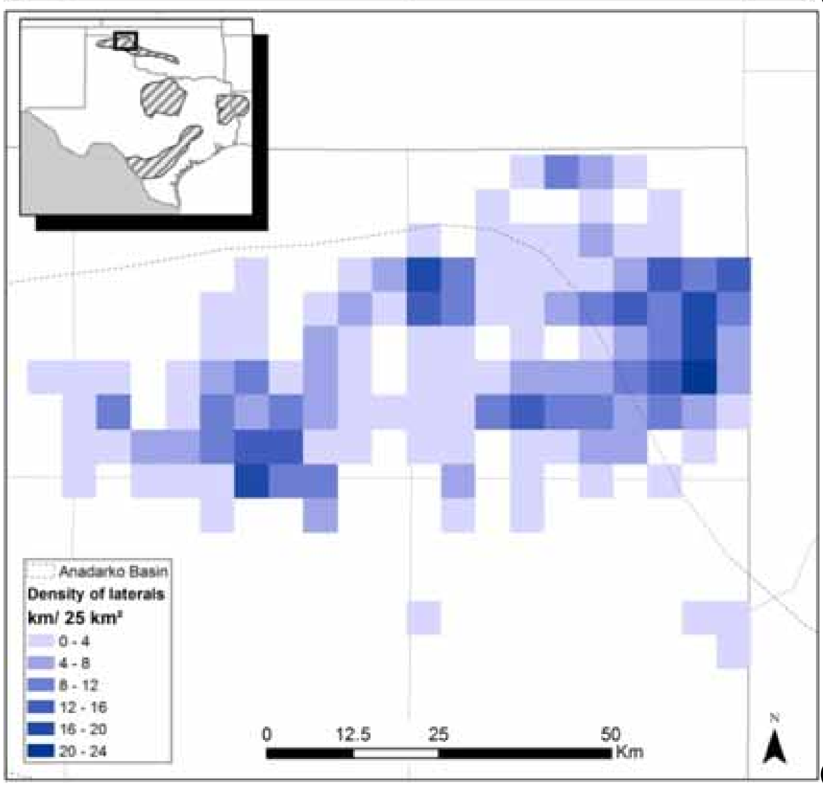
Table 6. Granite Wash county-level average lateral spacing for top producing counties

County Name	Sum lateral length / county area (km/km^2)	Average Lateral Spacing (1000 ft)
Wheeler	0.351	9.34
Hemphill	0.082	39.74
Roberts	0.036	90.54

Anadarko Basin: Cleveland Horizontals:



(a)

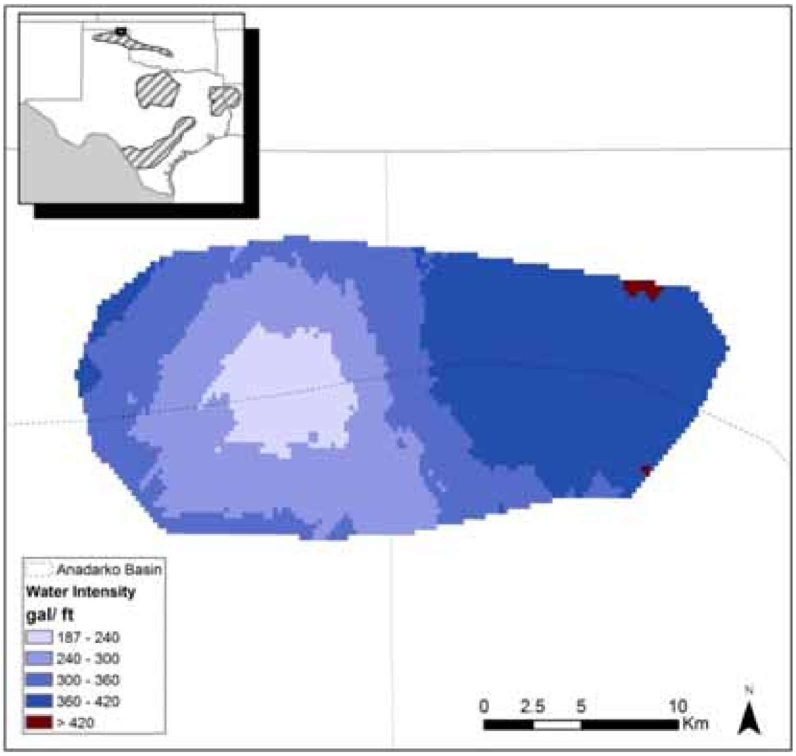


(b)

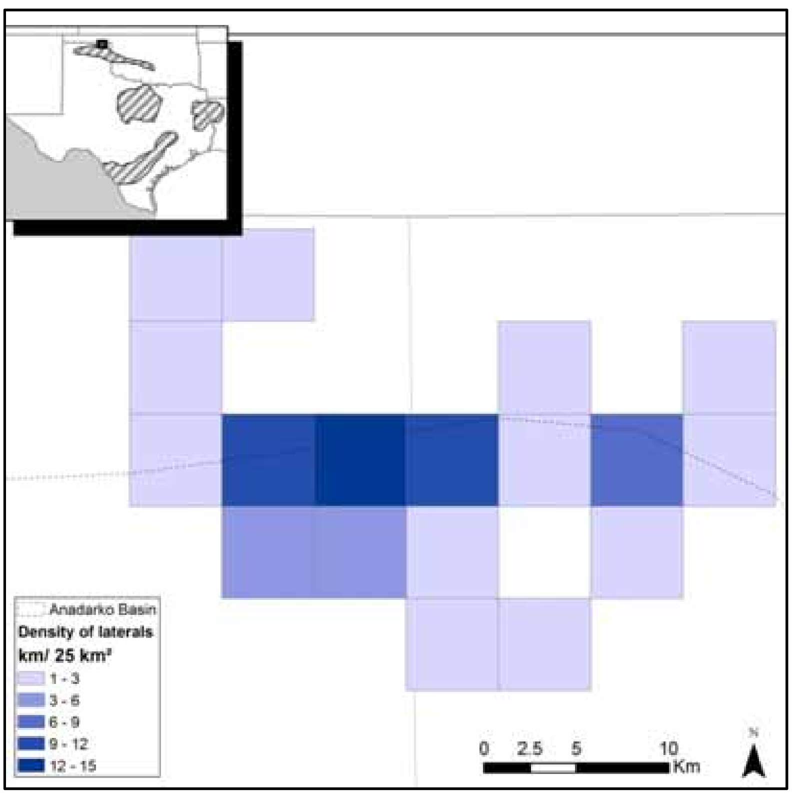
Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 34. Cleveland spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

Anadarko Basin: Marmaton Horizontals:



(a)

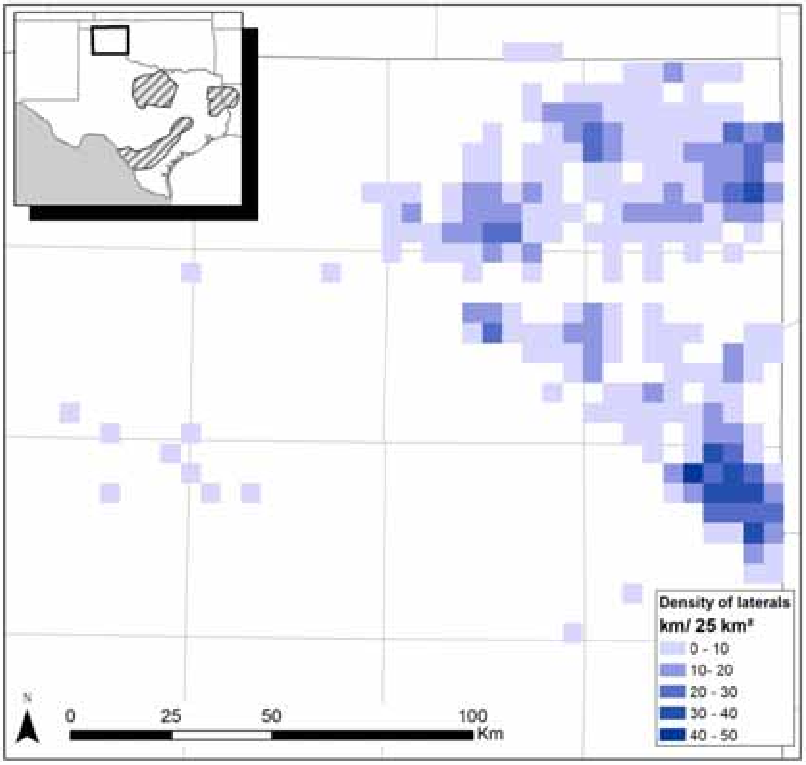


(b)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

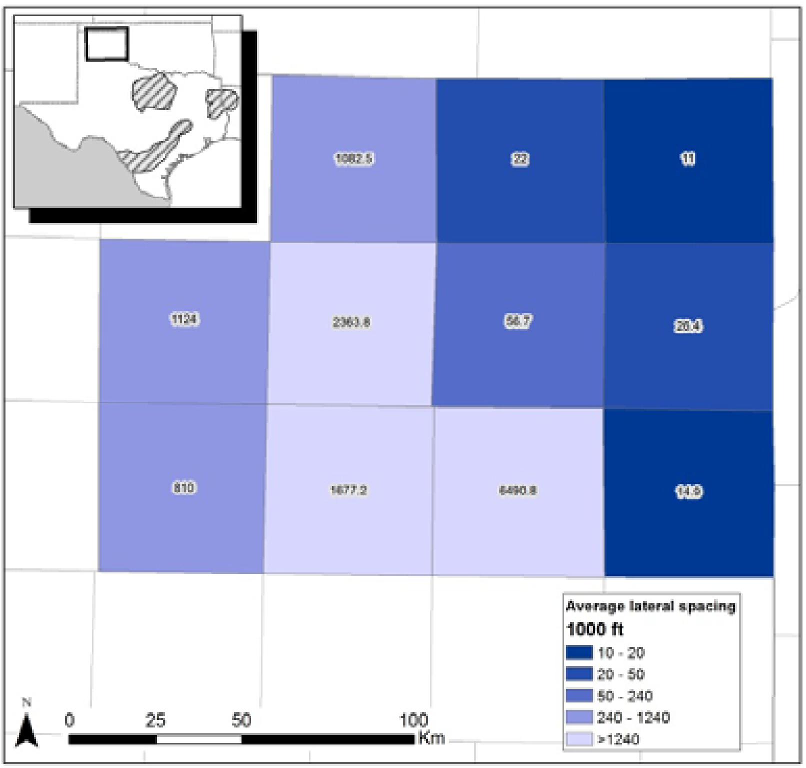
Figure 35. Marmaton spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

Anadarko Basin: Horizontals:



(a)

Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres



(b)

Figure 36. Anadarko spatial distribution of (a) water intensity; and (b) density of lateral (cumulative length per area).

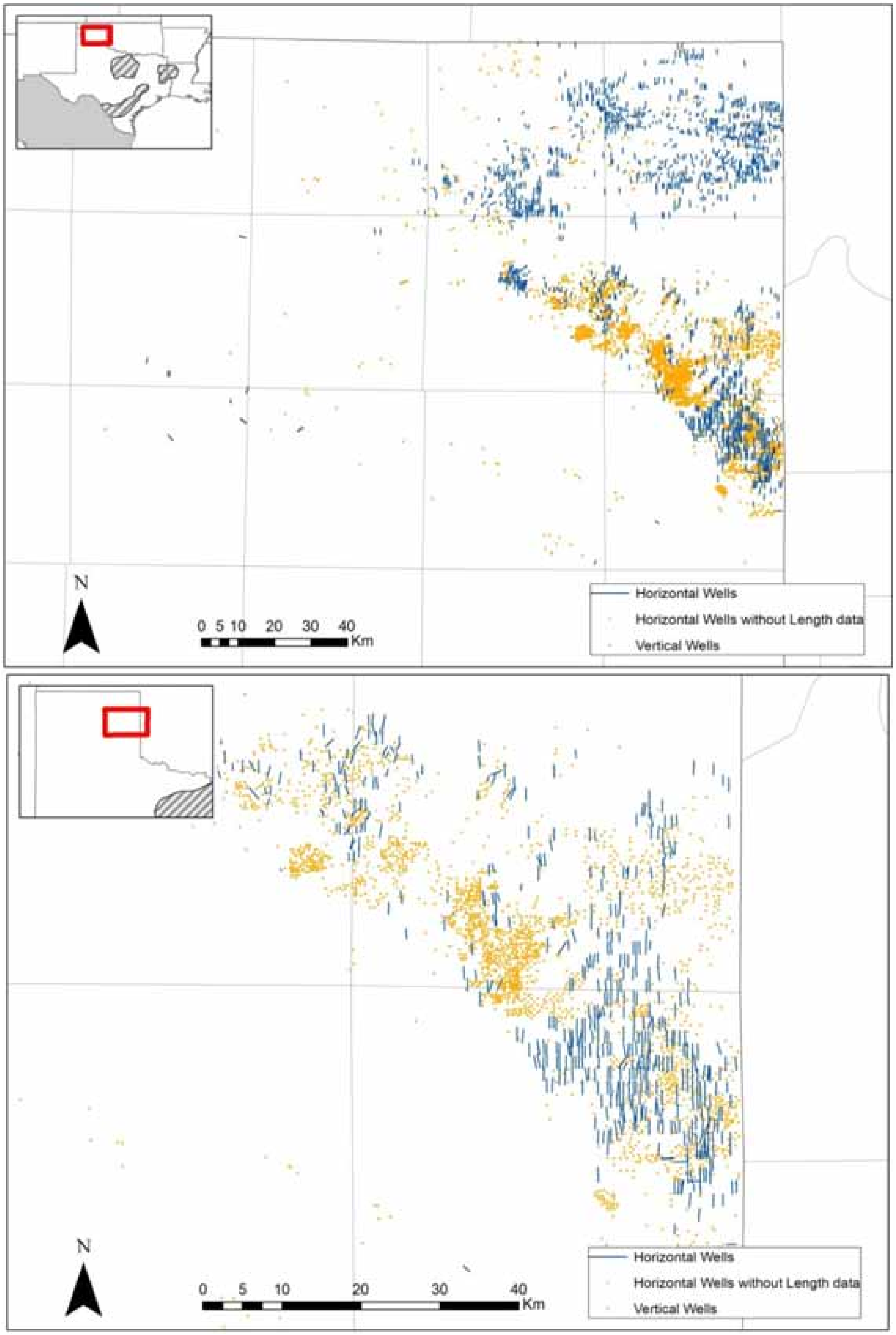
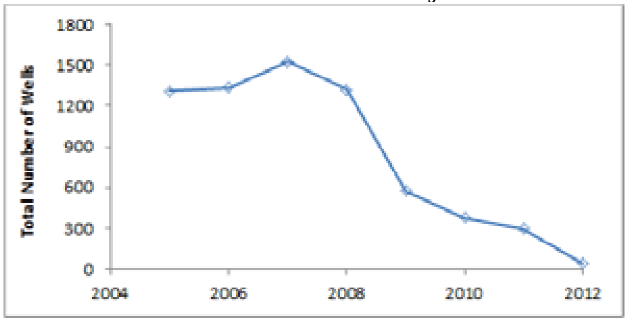
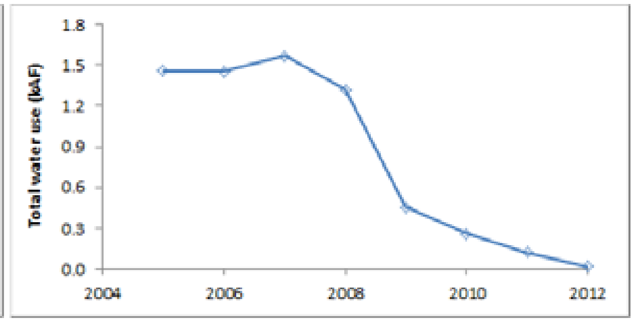


Figure 37. Map view of wells' lateral expression and vertical well location in the Anadarko Basin.

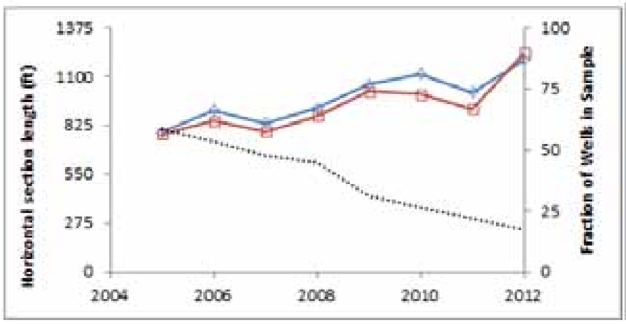
East Texas Basin: Cotton Valley Verticals



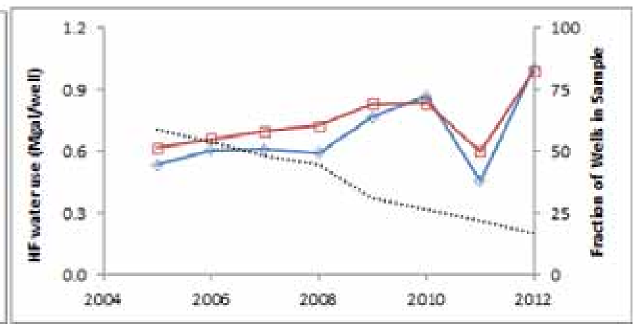
(a)



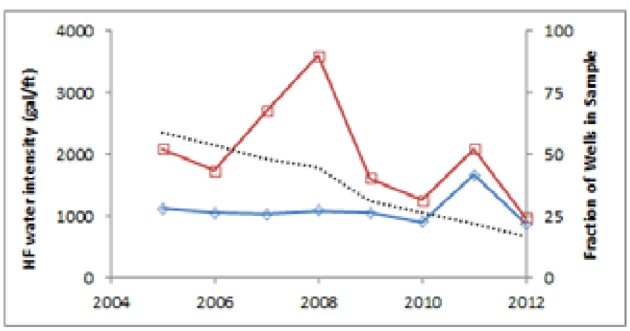
(b)



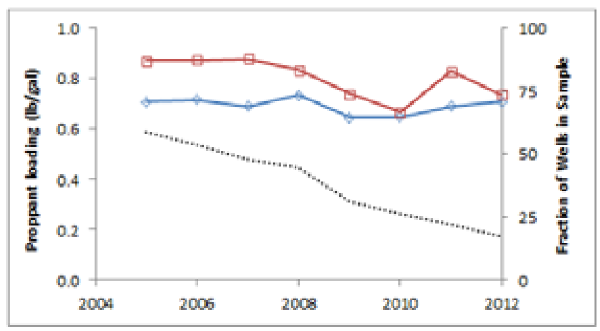
(c)



(d)



(e)

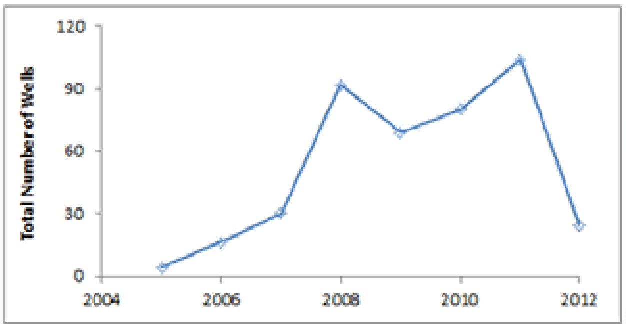


(f)

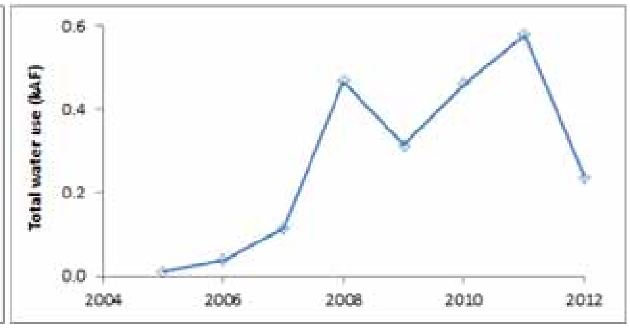
Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 38. Cotton Valley verticals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median vertical productive section length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

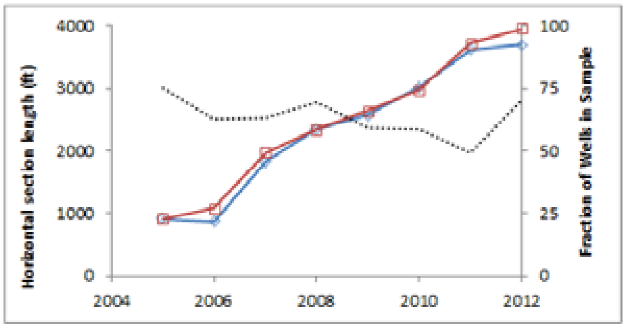
East Texas Basin: Cotton Valley Horizontals



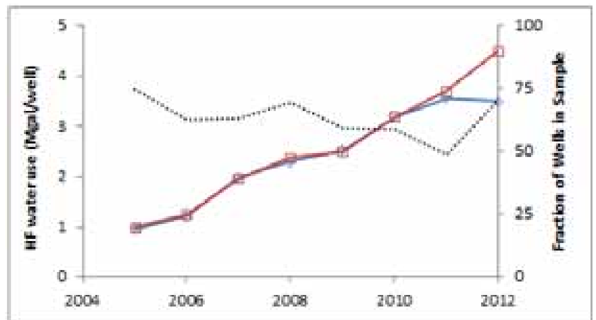
(a)



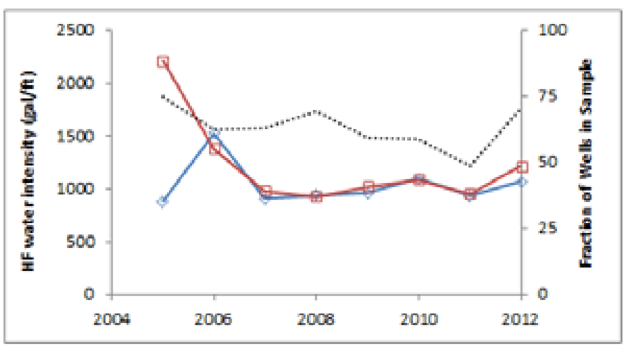
(b)



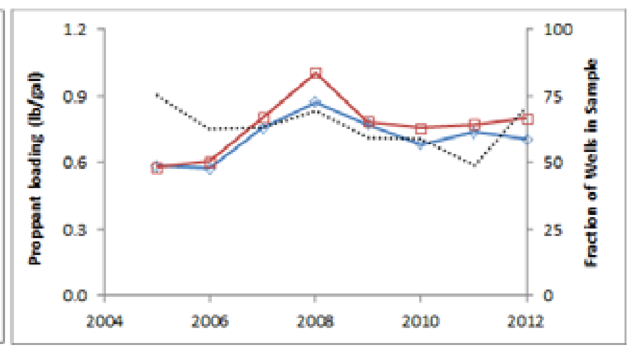
(c)



(d)



(e)



(f)

Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 39. Cotton Valley horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

East Texas Basin: Cotton Valley

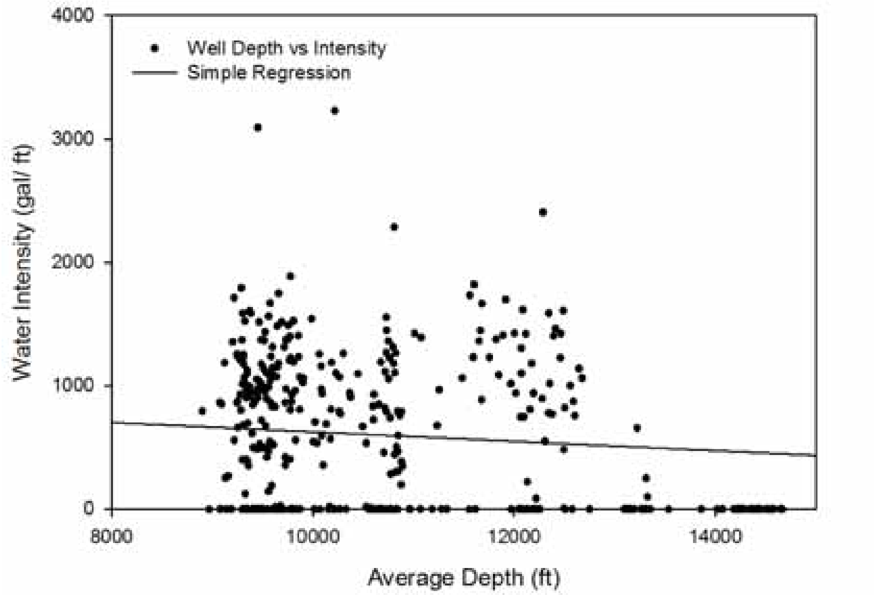
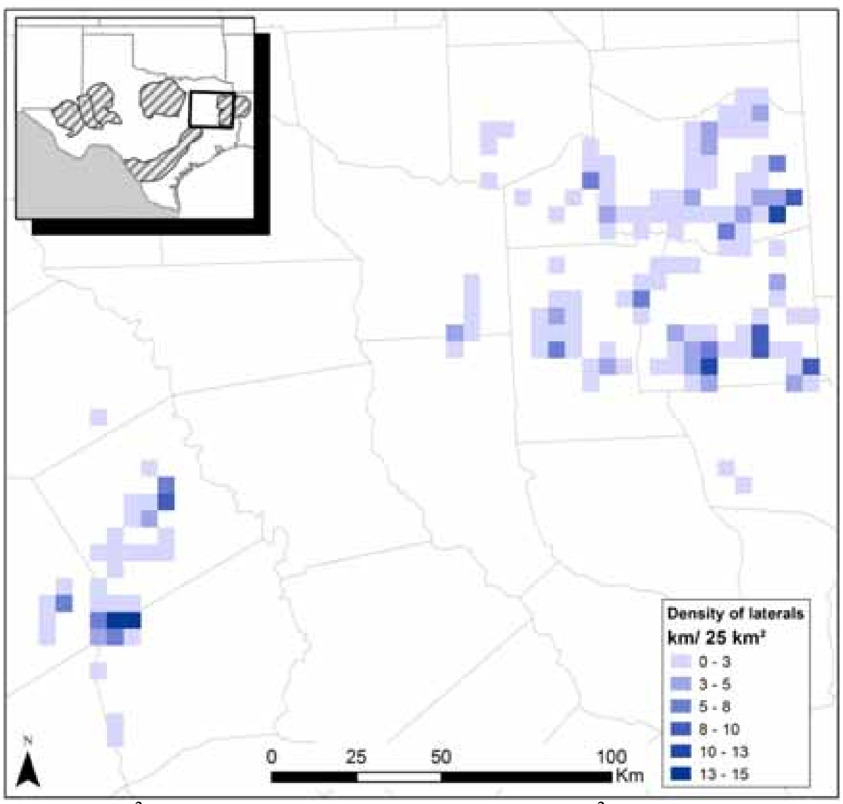


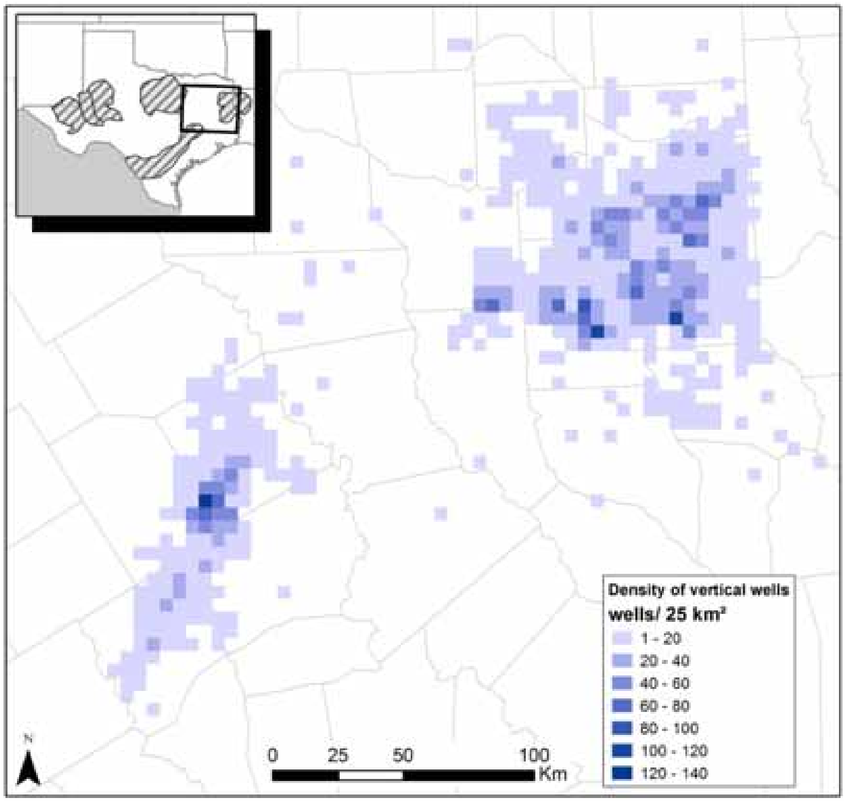
Figure 40. Cotton Valley horizontal water use intensity as a function of depth.



Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres

Figure 41. Cotton Valley spatial distribution of density of lateral (cumulative length per area).

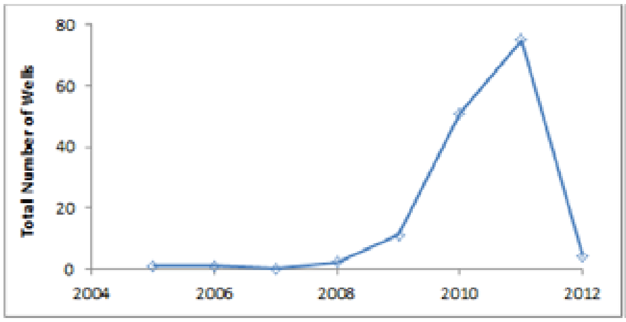
East Texas Basin: Cotton Valley

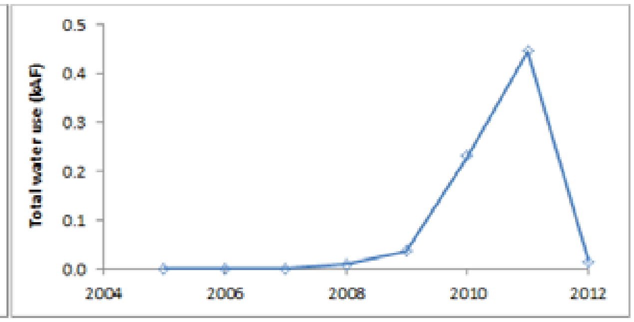


Note: 25 km^2 = 154 × 40 acres, that is, 154 wells/25 km^2 = 1 well/40 acres
Note: Cotton Valley wells drilled before 2005 are not included (see Nicot et al., 2011 for details).

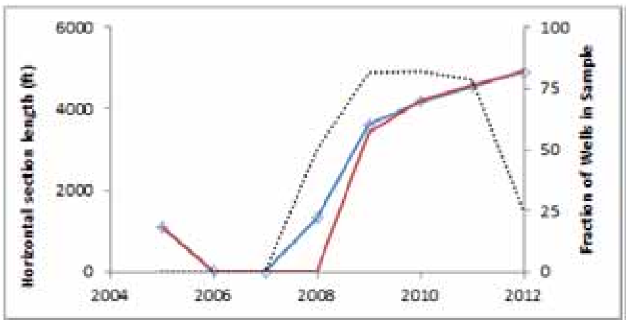
Figure 42. Cotton Valley spatial distribution of density of vertical wells (years 2005-2011).

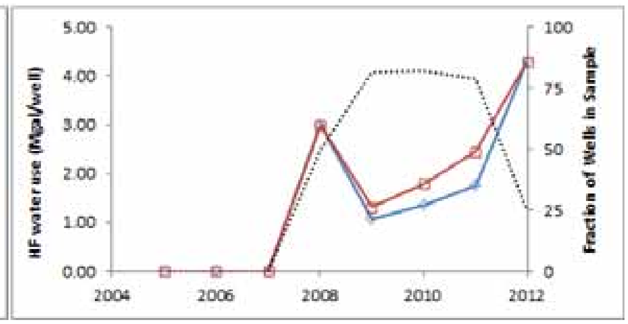
Gulf Coast Basin, Olmos - Horizontal



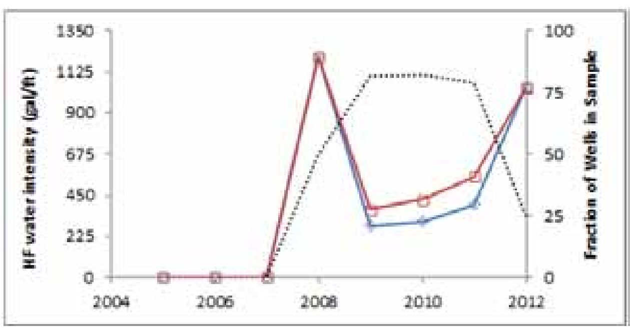


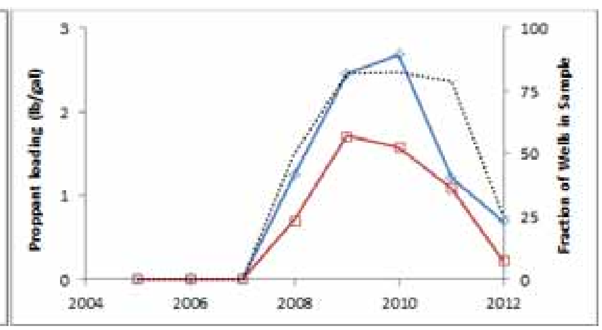
(a) (b)





(c) (d)





(e) (f)

Note: red squares represent average ; blue diamonds represent median; only partial data for 2012

Figure 43. Olmos horizontals, various historical parameters and coefficients for reported and estimated water use as a function of time: (a) number of wells; (b) water use; (c) average/median lateral length; (d) average/median water use per well; (e) average/median water use intensity; (f) average/median proppant loading.

III-2. Current Water Consumption and Sources

III-2-1 Information about Recycling/Reuse and Brackish Water Use

We collected information about recycling/reuse and brackish water use gathered during discussions with operators (Table 7). The amount of fresh water used is quite unequal across the different plays as a function of the local conditions. It can be as low as 20% in Far-West Texas or nearly 100% in East Texas. Collecting a sufficient amount of information concerning recycling/reuse and brackish water use is an improvement over the 2011 report which overall underestimated it. Reuse is limited by the amount of flow back that varies across plays. We could not document volumes of water recycled from wastewater treatment plants, but the TCEQ lists ~30 municipal and industrial facilities located in the Barnett Shale and Eagle Ford Shale plays that provide water to the industry (Figure 44). Groundwater/surface water could be extremely variable within a single play, but water data also reflect local conditions (Table 8): heavy surface water use towards the eastern part of the state and reliance on groundwater (sometimes brackish) elsewhere. The following short paragraphs discuss recycling/reuse and brackish water use and GS/SW split in major plays/regions.

Barnett Shale: For the most part, operators use fresh surface water in this play (estimated at 80% of “new” water). This is a change from the 50%+ groundwater use estimated in 2006 in Bené et al. (2007) and Nicot and Potter (2007). Some operators use brackish water, particularly in the combo play and on the western edges of the play. Some also use outfall from wastewater treatment plants. Overall, little recycling/reuse and brackish water use is currently occurring in this play as compared to other plays further west or south.

Eagle Ford Shale: Operators rely mostly on groundwater (estimated at 90% of “new” water) and there is a significant amount of brackish water being used (currently estimated at 20% but variable among operators). Several aquifers are brackish in the footprint of the play: the Gulf Coast aquifers and the Wilcox aquifers as well as the downdip section of the Carrizo aquifer.

Haynesville Shale and East Texas Basin: Water is generally plentiful in East Texas and no significant recycling/reuse and use for brackish water was documented during this study. We estimated it at 5%, mostly from treatment plants and produced water from Cotton Valley wells. We estimated that about 70% of the “new” water is groundwater.

Permian Basin: A significant percentage (30% or more) of the HF water used in both the Midland and Delaware basins is brackish. Nearly all of the water used is groundwater tapping aquifers such as the Ogallala (which is often brackish towards its southern domain, where the industry has many HF operations), and the Dockum, Trinity Edwards, Capitan, and other aquifers. The industry currently does little recycling/reuse, although several companies use produced water from conventional oil and gas operations. Such produced water has relatively low salinity at several places in the basin.

Anadarko Basin: This basin has hosted much recycling/reuse (estimated at 20%) and use of brackish water (estimated at 30%). Most of the “new” water is groundwater (estimated at 80%).

III-2-2 2011 HF Water Use and Consumption

Combining information collected from the IHS database, industry information, and selected information from the 2011 report results in an estimated water use for HF of ~81,500 AF across the state in 2011 (Table 9). The Barnett Shale and the Eagle Ford shale used a similar amount of water (~25 kAF), but less fresh water was used in the Eagle Ford. The Permian Basin is catching up (~15 kAF), but it uses relatively less fresh water than the two shale plays. Water use in the Texas section of the Haynesville Shale is becoming subordinate to other plays located in the same area (for example, Cotton Valley). County-level water use (Table 10) shows that many counties across the state have some HF water use (126 counties with >1AF in 2011 and 26 counties with >1kAF). The top 10 HF users consist of Tarrant County in the Barnett core (8.8 kAF), Webb County in the southern Eagle Ford (4.6 kAF), Johnson County in the core of the Barnett Shale (4.2 kAF), Karnes County in the Eagle Ford (3.9 kAF), Wheeler County in the Granite Wash of the Anadarko Basin (3.8 kAF), Dimmit County in the Eagle Ford (3.7 kAF), Denton County in the core of the Barnett Shale (3.2 kAF), Montague County in the combo play of the Barnett Shale (3.2 kAF), La Salle County in the Eagle Ford (2.9 kAF), and Wise County in the core of the Barnett Shale (2.3 kAF). The top ten counties total about half of the HF water use in the state. The top 10 counties stay the same when only water consumption is considered despite some reshuffling because of the variable impact of recycling/reuse and brackish water use.

In the next section we compare our current findings to the findings of the 2011 report (that projected a water use of 62 kAF in 2011, Table 9) and explain the discrepancies.

Table 7. Estimated percentages of recycling/ reused and brackish water use in main HF areas in 2011.

Play / Region	**Type**	**Current (2011) %**
Permian Far West	Recycled/reused	0%
	Brackish	80%
	Fresh	**20%**
Permian Midland	Recycled/reused	2%
	Brackish	30%
	Fresh	**68%**
Anadarko Basin	Recycled/reused	20%
	Brackish	30%
	Fresh	**50%**
Barnett Shale	Recycled/reused	5%
	Brackish	3%
	Fresh	**92%**
Eagle Ford Shale	Recycled/reused	0%
	Brackish	20%
	Fresh	**80%**
East Texas Basin	Recycled/reused	5%
	Brackish	0%
	Fresh	**95%**

Table 8. Estimated groundwater / surface water split (does not include recycling / reuse)

Play / Region	Groundwater	Surface Water
Barnett Shale	20%	80%
Eagle Ford Shale	90%	10%
East Texas Basin	70%	30%
Anadarko Basin	80%	20%
Permian Basin	100%	0%

Table 9. HF water use in 2008 and 2011compared to the 2011 projected water use from 2008.

Play / Region Unit: kAF	2011 Actual Water Use	Fraction Non-R/R Non-brackish	2011 Actual Water Consumption	2011 Projected Water Use
Barnett Shale	25.75	0.92	23.69	33.08
Eagle Ford Shale	23.76	0.8	18.81	10.07
East Texas Basin	7.54	0.95	7.06	8.46
Anadarko Basin	6.52	0.5	3.21	2.26
Permian Basin	14.44	0.68 / 0.2	8.55	7.26
Gulf Coast Basin	3.49	0.95 / 0.8	3.31	1.00
Statewide	81.51	0.79*	64.63	62.13

FrackingWaterUse2008&2011_Bob-JPComp_2.xls

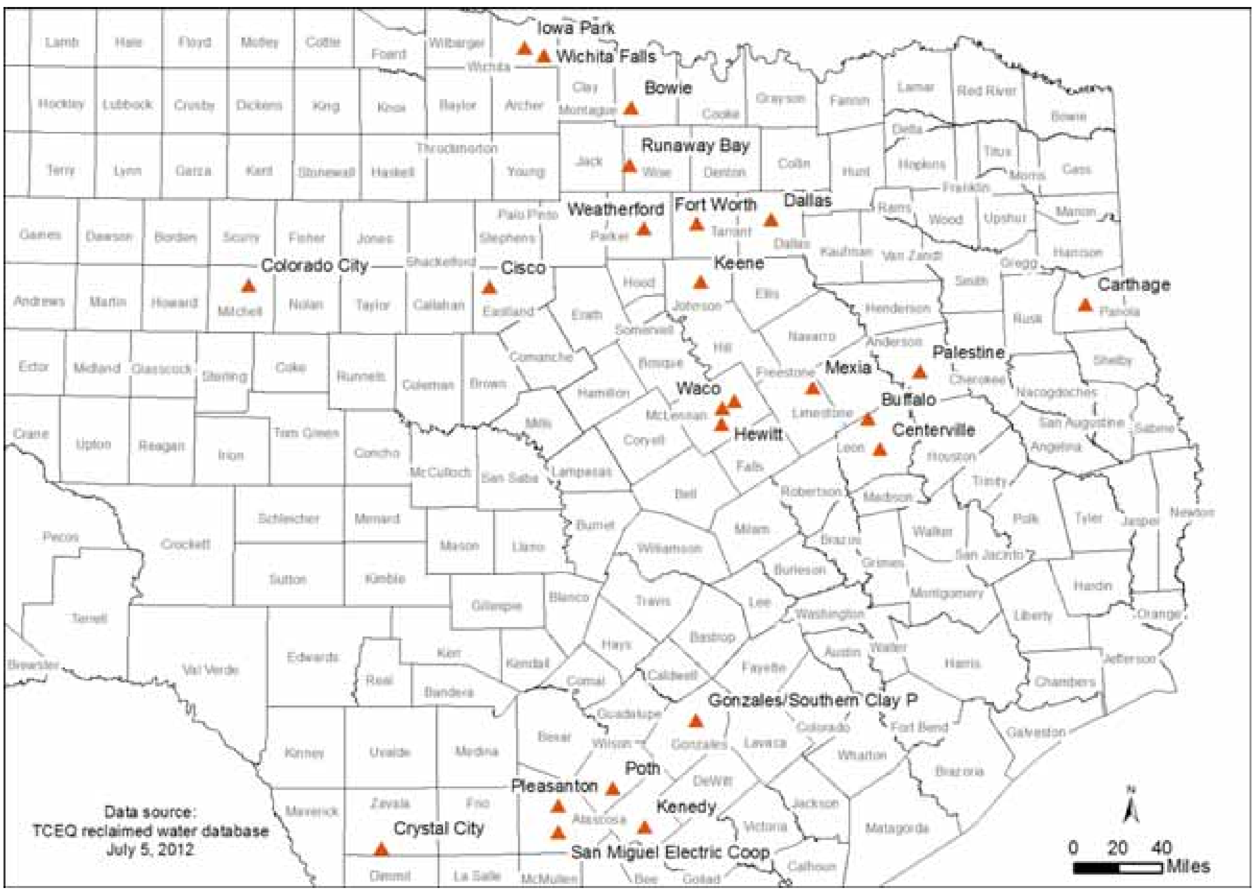
*: computed from state consumption and use columns (sum of other rows)

Table 10. County-level estimate of 2011 HF water use and water consumption (kAF).

County	HF Water Use (kAF)	HF Water Consumption (kAF)	County	HF Water Use (kAF)	HF Water Consumption (kAF)
Andrews	1.391	0.946	Limestone	0.268	0.214
Angelina	0.007	0.006	Lipscomb	0.382	0.191
Archer	0.017	0.016	Live Oak	0.972	0.777
Atascosa	1.009	0.807	Loving	0.189	0.038
Bee	0.066	0.053	McMullen	1.752	1.401
Borden	0.033	0.023	Madison	0.204	0.163
Brazos	0.238	0.191	Marion	0.010	0.010
Brooks	0.008	0.006	Martin	2.035	1.384
Burleson	0.247	0.197	Maverick	0.192	0.154
Caldwell	0.075	0.060	Midland	1.573	1.070
Carson	0.085	0.042	Milam	0.034	0.027
Cherokee	0.010	0.009	Mitchell	0.018	0.012
Clay	0.058	0.053	Montague	3.221	2.963
Cochran	0.031	0.021	Moore	0.076	0.038
Coke	0.001	n/a	Nacogdoches	1.128	1.072
Cooke	1.480	1.362	Newton	0.098	0.093
Crane	0.159	0.108	Nolan	0.011	0.008
Crockett	0.475	0.323	Nueces	0.016	0.013
Crosby	0.012	0.008	Ochiltree	0.273	0.136
Culberson	0.166	0.033	Orange	0.006	n/a
Dallas	0.079	0.073	Palo Pinto	0.041	0.038
Dawson	0.089	0.061	Panola	0.966	0.917
Denton	3.249	2.989	Parker	1.086	1.000
DeWitt	2.151	1.721	Pecos	0.110	0.022
Dimmit	3.706	2.965	Polk	0.133	0.126
Ector	0.756	0.514	Potter	0.044	0.022
Ellis	0.038	0.035	Reagan	1.240	0.843
Erath	0.012	0.011	Reeves	0.522	0.104
Fayette	0.132	0.106	Roberts	0.393	0.197
Franklin	0.014	0.014	Robertson	0.306	0.245
Freestone	0.424	0.339	Runnels	0.004	0.003
Frio	0.729	0.583	Rusk	0.158	0.150
Gaines	0.142	0.096	Sabine	0.147	0.139
Garza	0.001	n/a	San Augustine	1.622	1.541
Glasscock	1.434	0.975	Schleicher	0.090	0.061
Gonzales	2.224	1.779	Scurry	0.010	0.007
Grayson	0.021	0.020	Shackelford	0.002	0.002
Gregg	0.025	0.024	Shelby	1.419	1.348
Grimes	0.095	0.076	Sherman	0.002	0.001
Guadalupe	0.018	0.014	Smith	0.005	0.005
Hansford	0.011	0.005	Somervell	0.287	0.264
Hardeman	0.017	0.012	Starr	0.036	0.029
Harrison	0.893	0.849	Sterling	0.057	0.039
Hemphill	1.462	0.731	Stonewall	0.001	n/a
Henderson	0.012	0.012	Sutton	0.034	0.023
Hidalgo	0.059	0.047	Tarrant	8.805	8.101
Hill	0.131	0.120	Terrell	0.010	0.007
Hockley	0.005	0.003	Terry	0.003	0.002
Hood	0.645	0.593	Titus	0.003	0.003

County	HF Water Use (kAF)	HF Water Consumption (kAF)	County	HF Water Use (kAF)	HF Water Consumption (kAF)
Houston	0.178	0.142	Tyler	0.076	0.072
Howard	0.552	0.376	Upshur	0.004	0.004
Hutchinson	0.005	0.002	Upton	1.761	1.198
Irion	0.875	0.595	Ward	0.568	0.114
Jack	0.048	0.044	Washington	0.036	0.029
Jasper	0.087	0.083	Webb	4.596	3.677
Johnson	4.192	3.857	Wheeler	3.792	1.896
Karnes	3.869	3.095	Wilson	0.417	0.334
Kenedy	0.006	0.005	Winkler	0.062	0.012
Kleberg	0.034	0.028	Wise	2.314	2.129
La Salle	2.901	2.321	Yoakum	0.018	0.013
Lavaca	0.118	0.094	Young	0.008	0.007
Lee	0.131	0.105	Zapata	0.032	0.026
Leon	0.273	0.218	Zavala	0.407	0.127
			SUM	**81.50 kAF**	**64.63 kAF**

Note: filtered at 0.001 kAF FrackingWaterUse2008&2011_Bob-JPComp_2.xls

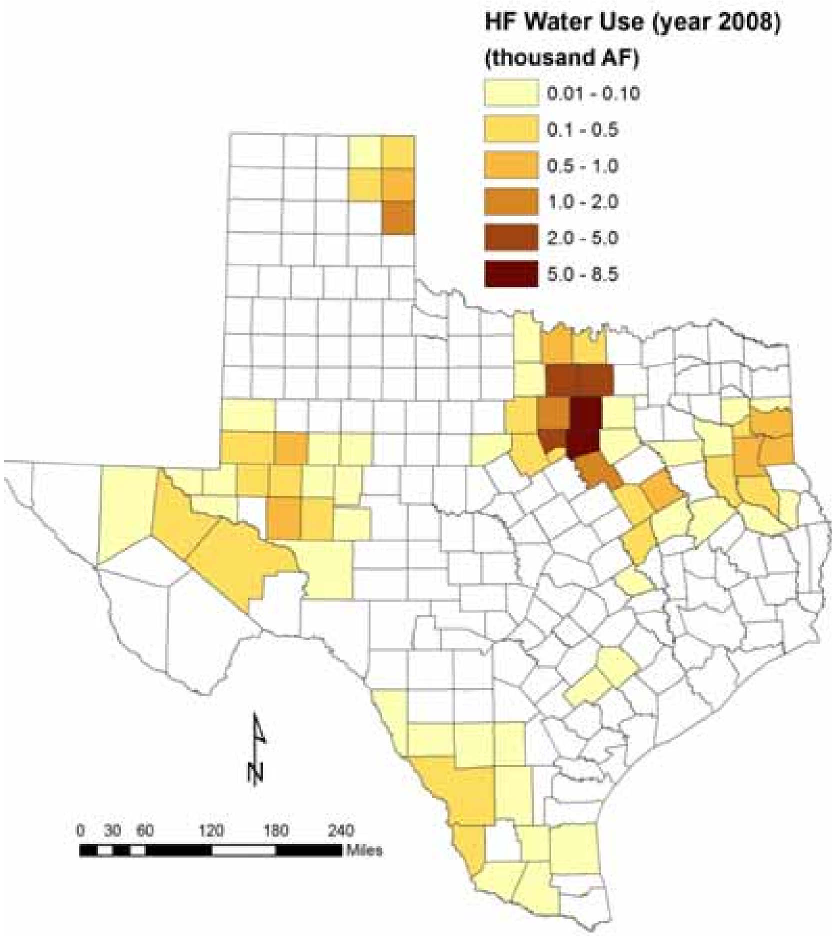


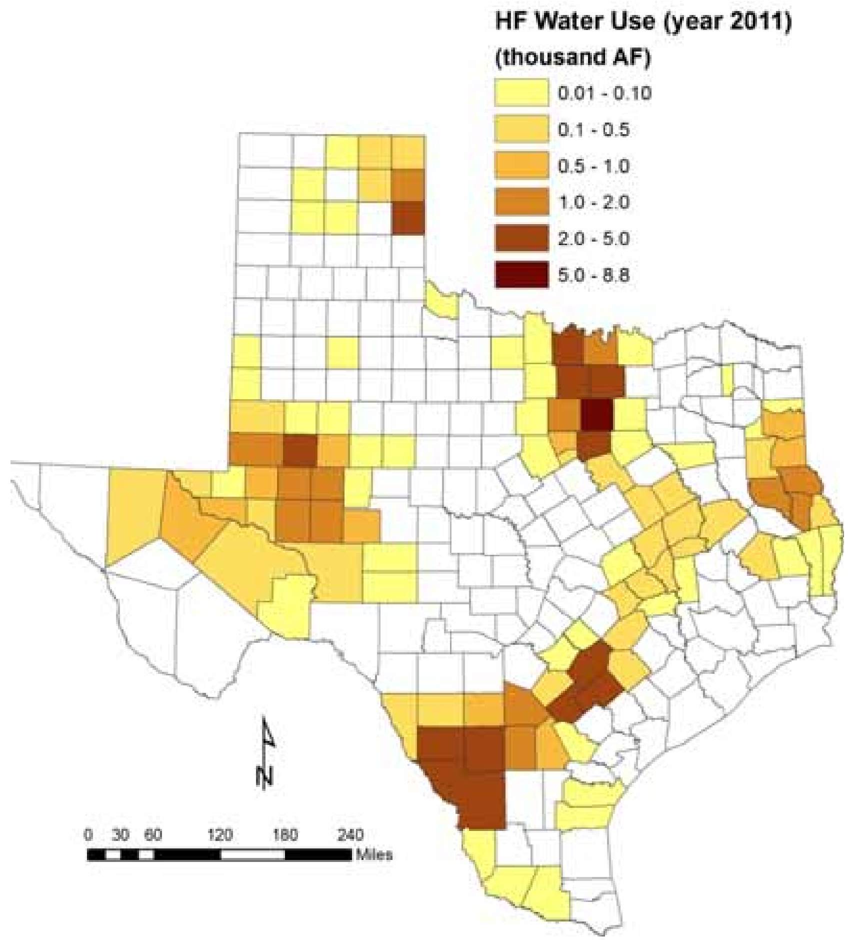
Source: TCEQ, 2012

Figure 44. Location of waste water treatment facilities that provide or have provided water to the industry for HF as of July 2012.

III-3. Comparison to Earlier Findings

Projections made in 2009 for 2011 in the 2011 report underestimated water use by about 30% (81.5 kAF compared to 62.1 kAF, Table 9). It is important to understand the underlying causes in order to develop better projections in this document. Comparing actual water use in 2008 and 2011 (Figure 45) shows (1) extension of HF across the state, Barnett Shale stays relatively steady, fracturing in the Haynesville Shale and Anadarko Basin expands, and the Eagle Ford becomes much more prominent as does the Permian Basin. A bar plot illustrates the county-by-county discrepancies between projections and actual numbers (Figure 46). A cross-plot is a different way of presenting the same information (Figure 47), and it is apparent that most counties with larger water use (dots in the upper right-hand side of the side) were correctly accounted (no dots on either the x- or y-axis), even if it was underestimated (dots mostly below the 1:1 line). Major discrepancies occurred because there was no Barnett extension outside of the core area (for example, Bosque, Comanche, Erath, and Palo Pinto counties in Figure 46), and because of more and faster development in the Eagle Ford Shale and Permian Basin. Both these factors are connected to the drop in gas price and increase in oil price in the past 2 or 3 years, parameters notoriously difficult to predict.





~36,000 AF
(Nicot el al., 2011)

~81,500 AF
including ~17,000 AF of recycling/reuse
and use of brackish water

Figure 45. Spatial distribution of HF water use in 2008 and 2011.

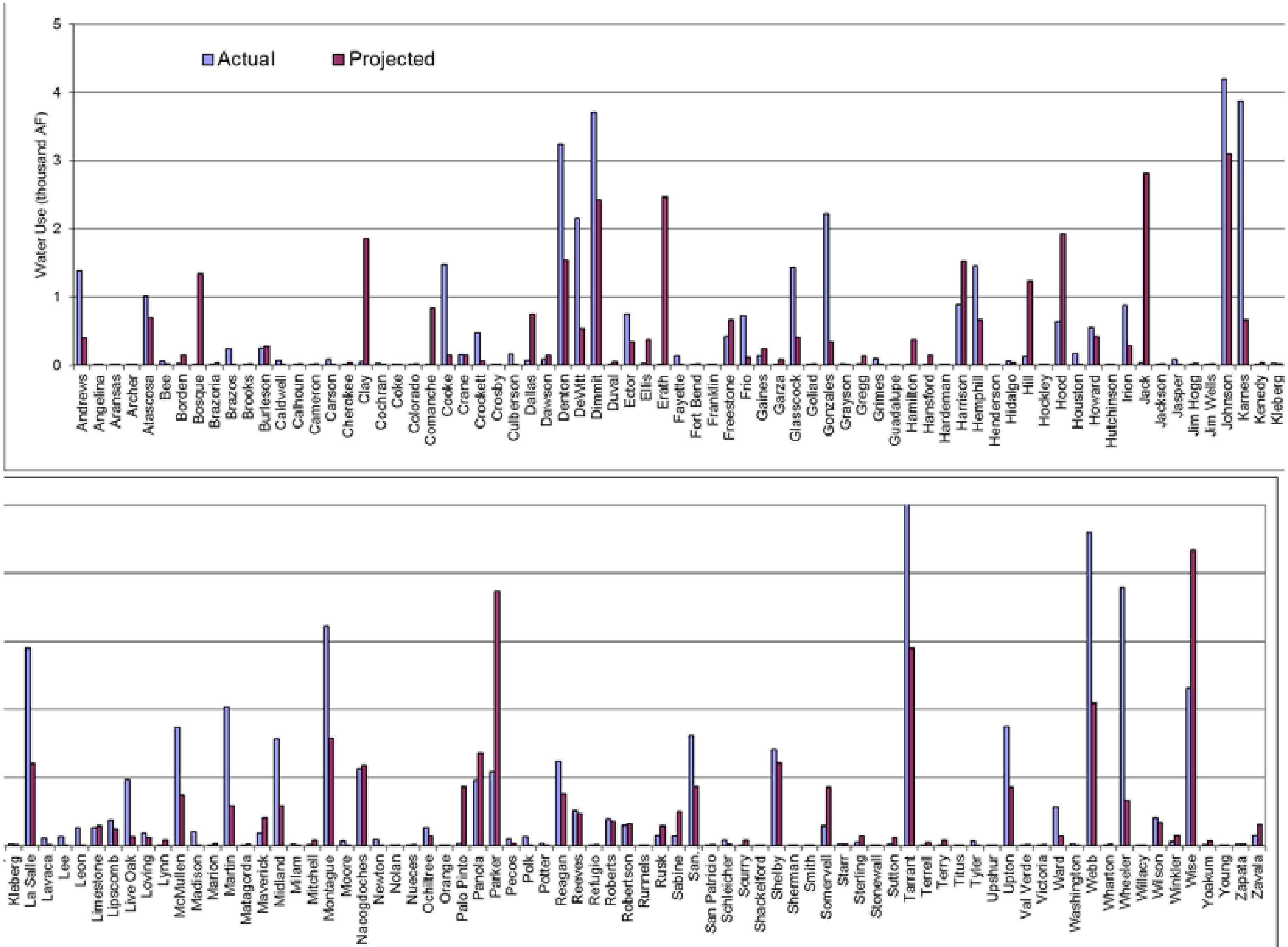
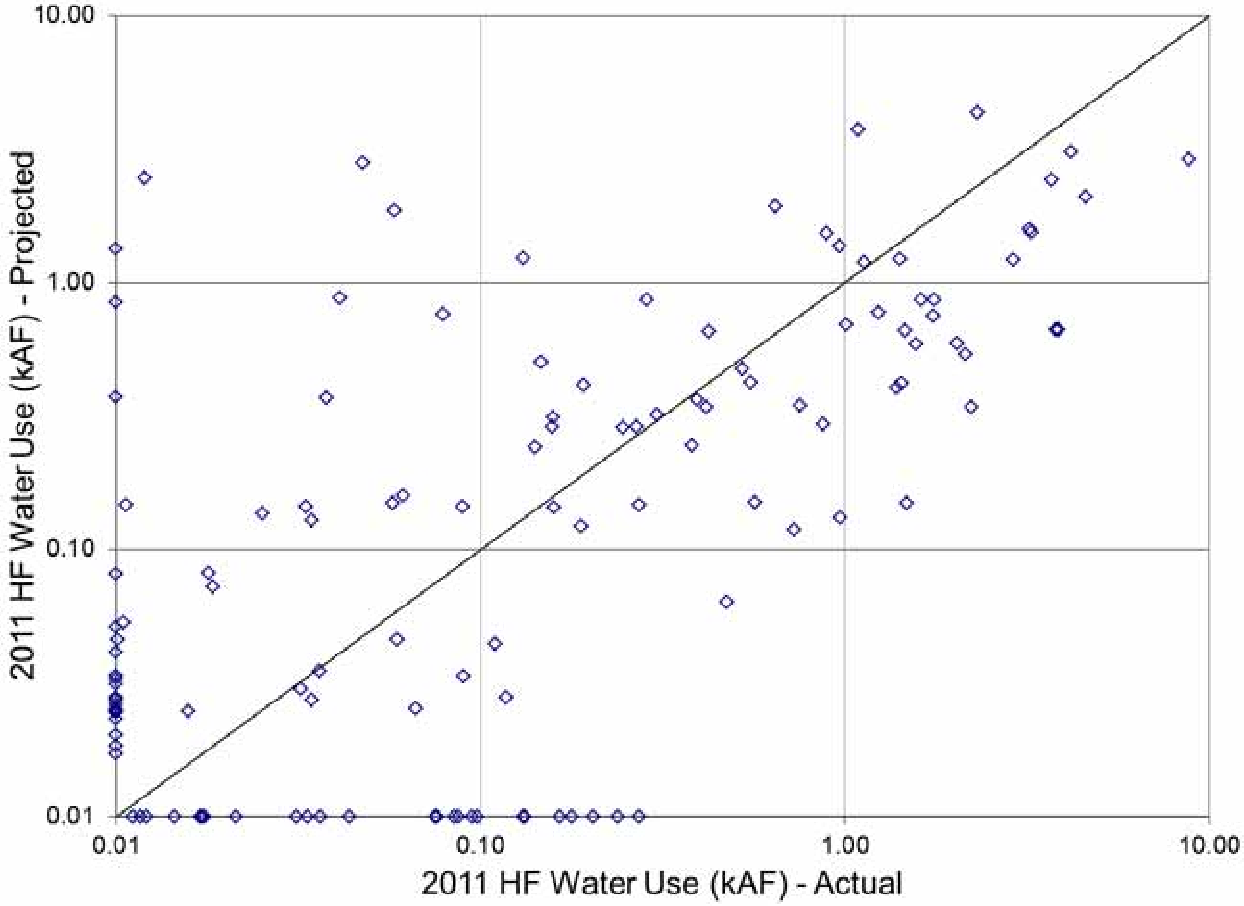


Figure 46. Bar plot comparison of 2011 actual water use to projections from 2009.



Note: Note the log-log scale.

Figure 47. County-level cross-plot comparison of 2011 actual water use to projections from 2008. Values on x- and y- axis represent counties whose actual (y-axis) / projected (x-axis) water use is 0. A total of 168 counties are represented.

III-4. Drilling Water Use

In the course of the study, we also collected information about drilling water use. Results are not sufficiently representative to change results presented in the 2011 report amounting to 8 kAF. The general observation, though, is that drilling requires water of better quality than HF although in smaller amounts (Table 11). The amount of water used depends on the length of the well and on operator preferences but also, more importantly, heavily on local factors. For example, in the Eagle Ford the drilling muds used in drilling through horizontal sections (for example, Fan et al., 2011) are oil-based.

Table 11. Drilling water use information

Play / Region in 1000's gal/well	Range provided by operators	Comments
Barnett Shale	250	N/A
	210-420	~Fresh
	168	~Fresh
	500	~Fresh
Eagle Ford Shale	125	N/A
	420	N/A
	160	~Fresh
	126	~Fresh
	252-420	~Fresh
East Texas Basin	600	N/A
	840-1,100	~Fresh
	420	~Fresh
Anadarko Basin	200	N/A
	420	~Fresh
Midland Basin (Permian Basin)	84	~Fresh
	100	N/A
	210	~Fresh
	210-420	~Fresh
Delaware Basin (Permian Basin)	100	N/A
	210-420	Brackish

Note: fresh is defined as TDS<3,000 mg/L

IV. Water Use Projections

This section describes projections for HF water use and fresh-water consumption in Texas to year 2060. As described in the 2011 report, all projections entail many uncertainties and those caveats are still valid in this update. In general, the life of the plays was extended beyond 2060, less prospectivity was given to the gas window, and steeper development to the oil window section of plays or tight oil plays. The overall results is that the HF water use will have a broad plateau at ~125 kAF/yr around the 2020-2030 decade and then slowly decrease with time to 2060 and beyond (Figure 48). However, the amount of fresh water consumed (that is, not recycled or reused or brackish water) will stay relatively constant at ~70 kAF despite the increase in water use and then slowly subside with the decrease in HF activities. Fresh-water use will decrease for two reasons: (1) the industry is getting better at reusing flow back (but sometimes limited by the small fraction coming back) and at finding alternate sources of recycling (treatment plants, produced water from conventional wells) and at using brackish water because of the technological advances in additives tolerating more saline water. And (2) the Permian Basin, which may become the focus of HF in Texas in the long run, offers great production potential. In the Permian Basin, fresh water is at a premium and brackish water is already used by the industry.

Total oil and gas water use and consumption (combining HF, waterflooding, and drilling) is presented in Figure 49. Oil and gas water use, consistent with the definition of make-up fresh water used in this document, was computed by summing HF water use (Figure 48), drilling water use –with no change from the 2011 report, and waterflood water use –computed from the 2011 report by adding fresh and brackish water use. Oil and gas water consumption was computed by summing HF water consumption (Figure 48), drilling water use –with no change from the 2011 report and the additional note that water use and consumption are identical. Waterflood water consumption is the same as water use in the 2011 report that represented fresh water use. Projected oil and gas water use and consumption are dominated by HF. By design, in the 2011 report, drilling technology was projected to move the industry away from the use of fresh water. Progress in waterflooding was also projected to decrease fresh water requirements but to increase brackish water use until the whole industry relies only on saline water (not showed). Under these assumptions, oil and gas industry water use is projected to peak with a broad plateau at 180 kAF in the 2020-2030 decade, slowly declining to ~60 kAF by 2060. Fresh water consumption in the oil and gas industry is projected to reach a maximum of ~100 kAF before the end of this decade and then to slowly decrease to a low level of a few tens of thousands AF by the middle of the century.

We did not account for many unknowns that could possibly impact the results as they did in the Eagle Ford Shale when the industry switched from slick-water fracs to gel fracs in the oil window that use less water. The Eagle Ford was the only play in which we observed such a trend, everywhere else the trend (based on 2 to 5 years of data) shows an increase or a steady value in water intensity (Table 12). Data about recycling/reuse and brackish water use were derived from industry information of these uses as of today and in 2020 (Table 13). The most likely values from 2011 and 2020 are essentially estimated directly from the various responses in a given play. Extrapolation to 2060 and translation to high and low scenarios for all years starting in 2012 are speculative and are based on industry trends and on the general knowledge of the authors about fresh and brackish water aquifers and of their yields around the state. The amount of reuse cannot be larger than the amount of flow back / produced water from recently fractured wells and at the play level reuse is likely less because of the operational issues of transporting water. Some plays, such as the Haynesville and Eagle Ford Shales, are at a disadvantage for this; they produce back less than 20% of the injected water (Table 14). They, and others, could however take advantage of produced water from other formations.

We did not deviate much from the overall water use of the 2011 report because of constraints accounted for the 2011 report and related to drilling rig count, labor force availability/staff shortage, infrastructure development, and other factors. National rig count seems steady at ~2,000 or slightly lower in the past year (~50% of them in Texas), but drillers are improving at operating them, which suggests that the projections presented in this update are consistent with the number of drilling rigs currently available.

Cumulative water use is related to the eventual well density or lateral spacing. Ultimate average spacing between laterals, or vertical well density, is the parameter driving water use along with water intensity. Typical vertical well spacing is 1 well per 40 acres; that ratio can decrease to 1 well per 20 or 10 acres in some instances. Typical lateral spacing can be computed from 1 horizontal well per 160 acres. If lateral length is 5,000 ft, the resulting spacing between laterals is 1,400 ft. If the horizontal well density declines to 1 well per 40 acres, lateral spacing is 350 ft. This update document assumes a lateral spacing of 1000 ft, perhaps smaller in oil windows (Figure 51).

County-level projections for HF water use and water consumption are listed in Table 15. The county coverage is essentially the same as in the 2011 report with the addition of four counties in East Texas (Polk, Tyler, Jasper, and Newton counties, Figure 50). Total oil and gas (combining HF, waterflooding, and drilling) county-level projections are presented in Table 16.

The following paragraphs address HF projection issues specific to each play and region. Each play is represented by two plots. One plot compares projections from the 2011 report to projections from this update. The second plot displays water use and fresh water consumption in the high, low, and most likely scenarios. Only the latter is displayed in the first plot and is retained as the preferred set of projections to be used by the TWDB. As explained in the Methodology Section (Section II), low and high scenarios were derived by varying two factors: (1) the prospectivity factor, which assesses the ultimate amount of HF in a play, varies on a county and play basis from 1 to 0, with 1 meaning the county is within the core area and highly prospective (for example, Tarrant County in the Barnett Shale) and near- zero values suggesting that little of the county will be developed (for example ,Shackelford County in the Barnett Shale); and (2) coefficients for recycling/reuse and brackish water use (Table 13). The prospectivity factor was changed according to a sliding linear scale: a value of 1 stays at 1 but a value of 0.2 either goes to zero (low water use scenario) or 0.4 (high water use scenario). The change was made systematically with no tentative exercise to tailor it to each county/play couple. In the case of tight oil/ tight gas plays, a third factor was varied. This factor varies from 0 to 1 and addresses the spatial coverage of the county that could ultimately undergo HF. In the case of resource plays such as shale plays, the factor is constant and close to one because the whole footprint of the play is potentially a target for drilling. The only unknown is the well density which is accounted for through the prospectivity factor. In tight oil/gas plays, it cannot be assumed that the whole footprint of the formation will experience HF because some parts of it can be properly produced through conventional wells. This third factor was used in the East

Texas (Cotton Valley), Anadarko (Granite Wash), Gulf Coast (Austin Chalk), and Permian basins.

Barnett Shale: In this play with the longest history, we considerably decreased the prospectivity factors outside of the core area in the most likely scenario. That is, instead of increasing water use because of the expansion of the productive Barnett Shale footprint, we assumed that most of the HF will stay confined to the core area and stay relatively stable for a few years before slowly decreasing (Figure 52a). The peak from earlier projections has disappeared and water use should stay below 30 kAF and decrease more slowly than projected in the 2011 report. The high water use scenario projection (Figure 52b) displays a small increase in water use (but not in water consumption) in the 2020 decade because the prospectivity factors are closer to those used in the 2011 report.

Eagle Ford Shale: Projections for this play display a decrease in water use compared to those projected values of the 2011 report (Figure 53a) because of the observed decrease in water intensity that we assumed will hold in the future. The projections suggest a slow increase in water for the next 10 years with a broad peak at ~35kAF and a slow decrease beyond 2060. Unlike the Barnett with a clearly delimited core, we assumed that most counties in the Eagle Ford are highly prospective and thus there is not much variation between high and low scenario projections except when recycling/reuse and use of brackish water are included (Figure 53b).

Pearsall Shale: This gas play was briefly hydraulically fractured in the mid-2000's and has not received a lot of attention since then. However, initial production estimates suggest that the play will be produced in the future. We used the same water use parameters in the Pearsall as those in the Eagle Ford Shale because these plays are geographically close. Projections from the 2011 report were only slightly modified displacing the peak water use at ~10 kAF by about 5 years into the future (Figure 54a). As was the case for the Eagle Ford, the high and low scenarios are mostly impacted by the amount of recycling/reuse and brackish water use (Figure 54b).

TX-Haynesville and Bossier Shales: The Haynesville and Bossier Shales have declined in operator interest because of their relatively high operational cost and low gas prices. They are, however, still likely to produce significant amounts of gas in the future, albeit at a lower rate than anticipated in the 2011 report. Projections of this update document show a decreased and broader peak (Figure 55a), with annual water use slated to be no higher than ~12kAF. A minor player, the Haynesville-West play will possibly undergo some development on the western flank of the East Texas Basin and its water use projections stay similar to that of the 2011 report (Figure 56a), with a decrease peak as well. Low and high scenario projections stay relatively close together (Figure 55b), because there is little variability in terms of projected non-fresh water use (almost none).

Other East Texas Formations: This category includes all formations except the Haynesville and Bossier Shales, such as the Cotton Valley, James Lime, Bossier Sands, and others. The same water consumption data used in the Haynesville were used for this group of formations. Relative to the 2011 report projections, the projections derived in this update assumed a broader peak displaced toward the future by ~10 years (Figure 57a). Projected maximum water use is estimated at <5 kAF/yr. The small variance between water use and water consumption is explained by the location of the plays in East Texas where fresh water is relatively abundant and the large differences between the different scenario projections is due to the spread of the third factor, addressing spatial coverage of the formation of interest (Figure 57b).

Gulf Coast Formations: Amount of water use and consumption in the Gulf Coast Basin outside of the shale plays is very uncertain. The Gulf Coast Basin is the area in Texas that has experienced the least HF (Nicot et al., 2011) and explained the large range of projections between the different scenarios (Figure 58b). This category include formations such as the Olmos Sands and the Austin Chalk, and these projections assumed that water use will peak at ~8kAF in the 2020's (Figure 58a). Water consumption is assumed to be much lower because most of the plays are in South Texas, where there are some brackish water resources.

Anadarko Basin: Anadarko Basin consists mostly of the Granite Wash in Hemphill and Wheeler counties and the Marmaton/Cleveland in Ochiltree and Lipscomb counties. Current water use in this basin is much higher than anticipated in the 2011 report projections. We revisited prospectivity factors and the projected water use reaches a broad peak of ~9kAF in the 2020's (Figure 59a) with a smaller projected water consumption because of anticipated recycling/reuse and brackish water use. However, the uncertainty in final coverage put this basin in the same category as the Gulf Coast Basin and East Basin category, resulting in a large spread of potential outcomes (Figure 59b).

Permian Basin: As has the Anadarko Basin, the Permian Basin has grown much faster than anticipated and water use projections call for a plateau at ~40 kAF during the 2020-2040 period (Figure 60a) concomitant with a fairly stable fresh water consumption at 10-15 kAF. The large gap between water use and water consumption, much larger than presented in the 2011 report (Figure 60a), is due to the expectation of availability of significant amounts of brackish water and of their extensive use by the industry (as currently documented by anecdotal evidence). The large range in outcome from the different scenarios is related to the unknowns in spatial coverage of the non-shale plays (Figure 60b). We now turn to the description of the major components making up water use in the Permian Basin. Although the Barnett-Woodford system in the Permian Basin has received limited interest, we assume it will produce gas in the future (Figure 61a). The most likely scenario calls for a peak at ~5 kAF in 2035 but with the possibility of a high scenario with a much higher water use and a low scenario with no development. Development centered on the Wolfcamp is more certain and differences between high and low scenario projections were derived mostly from assumptions on the level of use of non-fresh water(Figure 61b). The other formations in the Permian Basin also display the same uncertainty related to the amount of spatial coverage ("third factor" as described above). The most likely scenario projection is estimated to have a broad peak in the 15-20 kAF range for many years with considerably less water consumption (Figure 61c).

Table 12. Recent trends in well completion and water use in hydraulic-fractured plays.

Play	Well Type	~# of Recent Wells/yr	Recent Trend (well/yr)	Water Use / well (Mgal)	Water Use Intensity (gal/ft)	Recent Trend (water use)
Barnett	H	1500	down / steady	n/a	1200	steady
Eagle Ford	H	1000	strongly up	n/a	850	down
TX-Haynesville	H	250	up	n/a	1400	steady
Granite Wash	H	250	strongly up	n/a	1200	steady / up
	V	60	strongly down	1500	800	steady
Cleveland	H	100	steady	n/a	250	steady
	V	20	down	1.7	2000	steady
Marmaton	H	30	strongly up	n/a	250	steady
	V	10	steady	1.0	2500	up
Cotton Valley	H	100	up	n/a	1000	steady
	V	300	strongly down	0.8	1200	steady
Olmos	H	50	up	n/a	1000	up
	V	100	strongly down	0.15	2500	steady
Wolfcamp	H	150	strongly up	n/a	900	strongly up
Wolfberry	V	2000	up	1.0	350	up
Canyon	V	300	down	0.4	500	up
Clear Fork	V	800	up	0.8	350	up
San Andres	H	50	strongly down	n/a	350	strongly up
	V	800	steady / up	0.15	500	steady

Table 13. Coefficients (%) to compute water consumption to be applied to total water use.

Play / Region		High Water Use	Most Likely	Low Water Use
Far West Permian Basin	**Recycling**			
	2011	0	0	0
	2020	0	50	40
	2060	0	40	40
	Brackish			
	2011	80	80	80
	2020	80	30	50
	2060	80	40	50
Permian Midland Basin	**Recycling**			
	2011	2	2	2
	2020	2	25	30
	2060	2	30	40
	Brackish			
	2011	30	30	30
	2020	30	40	40
	2060	30	40	50
Anadarko Basin	**Recycling**			
	2011	20	20	20
	2020	20	30	40
	2060	20	40	40
	Brackish			

Play / Region		High Water Use	Most Likely	Low Water Use
	2011	30	30	30
	2020	30	30	30
	2060	30	30	40
Barnett Shale	**Recycling**			
	2011	5	5	5
	2020	5	10	25
	2060	5	20	20
	Brackish			
	2011	3	3	3
	2020	3	15	20
	2060	3	25	25
Eagle Ford Shale	**Recycling**			
	2011	0	0	0
	2020	0	10	10
	2060	0	10	10
	Brackish			
	2011	20	20	20
	2020	20	40	50
	2060	20	50	50
South Texas	**Recycling**			
	2011	0	0	0
	2020	0	10	10
	2060	0	10	10
	Brackish			
	2011	20	20	20
	2020	20	40	50
	2060	20	50	50
East Texas	**Recycling**			
	2011	5	5	5
	2020	5	10	10
	2060	5	10	10
	Brackish			
	2011	0	0	0
	2020	0	0	10
	2060	0	10	10

Table 14. Estimated flow back/produced water volume relative to HF injected volume.

Play / Region	Comment
Delaware Basin (Permian Basin)	Close to 100% in year 1, 150% well life >200% well life
Midland Basin (Permian Basin)	50%-100% in year 1
Anadarko Basin	~50% in month 1, 90% at month 6
Barnett Shale	10-20% month 1, 20-60% well life 70% year1; 150% in 5 years
Eagle Ford Shale	20% over life; 20% over life
Haynesville Shale	20% over life; 15% over life
Cotton Valley Fm.	60% month 1, >100% well life; 40% or 100% over life

Table 15. County-level estimate of 2012-2060 projections for HF water use and water consumption (AF).

	Water Use (AF)											Water Consumption (AF)										
County	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
Anderson	0	31	58	89	119	131	139	124	105	85	66	0	23	41	64	86	97	104	92	76	61	46
Andrews	1,391	1,617	2,140	2,053	1,965	1,878	1,654	1,431	1,207	983	806	946	862	749	690	634	580	501	425	351	279	224
Angelina	7	60	160	260	360	379	345	310	276	241	207	6	56	144	231	315	327	293	260	228	196	165
Aransas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Archer	17	81	183	284	385	354	321	289	257	225	193	16	68	137	206	270	239	209	181	154	129	106
Armstrong	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Atascosa	1,009	2,902	2,638	2,589	2,594	2,598	2,602	2,314	1,953	1,591	1,230	807	2,064	1,583	1,500	1,443	1,386	1,329	1,144	935	736	545
Austin	0	0	98	195	293	264	234	205	176	146	117	0	0	59	115	169	148	129	110	92	75	59
Bailey	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bandera	0	0	0	0	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0
Bastrop	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Baylor	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bee	66	80	101	108	94	81	67	54	40	27	13	53	60	64	67	57	48	39	31	23	15	7
Bell	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bexar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Blanco	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Borden	33	228	638	892	899	906	764	622	480	338	230	23	122	223	307	303	300	248	198	150	104	69
Bosque	0	192	329	466	603	553	502	452	402	352	301	0	162	247	338	422	373	327	283	241	202	166
Bowie	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brazoria	0	41	60	79	97	91	79	67	55	43	31	0	31	38	49	59	54	46	38	31	24	17
Brazos	238	322	696	931	1,166	1,036	905	775	644	514	384	191	243	431	559	681	592	506	423	343	267	193
Brewster	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Briscoe	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brooks	8	37	49	62	62	54	46	38	30	22	14	6	28	31	38	38	32	27	22	17	12	8
Brown	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Burleson	247	331	943	1,409	1,877	1,676	1,474	1,273	1,071	867	665	197	250	580	840	1,090	952	819	690	567	447	334
Burnet	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Caldwell	75	90	116	103	90	77	64	52	39	26	13	60	68	73	64	55	46	38	29	22	14	7
Calhoun	0	25	33	42	42	37	31	26	21	15	10	0	19	21	26	26	22	18	15	11	8	5
Callahan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cameron	0	37	50	62	62	54	46	38	30	22	14	0	28	31	38	38	32	27	22	17	12	8
Camp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Carson	85	0	0	0	0	0	0	0	0	0	0	42	0	0	0	0	0	0	0	0	0	0
Cass	0	10	25	41	56	68	60	52	45	37	30	0	9	24	38	52	60	52	45	38	31	24
Castro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chambers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cherokee	10	70	128	186	244	284	253	221	190	158	126	9	66	122	173	223	254	221	189	159	129	101
Childress	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Clay	58	194	355	516	678	621	565	508	452	395	339	53	164	266	374	474	419	367	318	271	227	186
Cochran	31	94	121	149	176	203	180	158	135	113	90	21	50	42	51	59	67	59	50	42	35	27
Coke	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coleman	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Collin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Collingsworth	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Colorado	0	38	517	996	1,462	1,314	1,166	1,018	870	722	574	0	29	312	587	843	741	643	548	458	371	287
Comal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Comanche	0	125	228	332	436	392	349	305	261	218	174	0	105	171	241	305	265	227	191	157	125	96
Concho	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Cooke	1,480	1,653	1,294	934	575	215	0	0	0	0	0	1,362	1,396	970	677	402	145	0	0	0	0	0
Coryell	0	289	1,012	947	684	421	158	0	0	0	0	0	244	759	686	479	284	103	0	0	0	0

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
Cottle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Crane	159	339	438	559	681	802	729	656	583	510	438	108	181	153	189	223	257	229	203	177	152	128
Crockett	475	996	1,636	1,946	1,760	1,475	1,190	905	620	335	149	323	531	573	669	594	489	387	288	194	103	45
Crosby	12	0	0	0	0	0	0	0	0	0	0	8	0	0	0	0	0	0	0	0	0	0
Culberson	166	141	188	576	963	1,280	1,163	1,047	931	814	698	33	75	66	149	231	290	262	235	207	180	154
Dallam	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dallas	79	654	1,018	848	679	509	339	170	0	0	0	73	553	763	615	475	343	220	106	0	0	0
Dawson	89	476	724	918	954	990	844	699	553	408	294	61	254	253	308	308	308	257	208	160	115	80
Deaf Smith	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Delta	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Denton	3,249	3,159	2,106	1,053	0	0	0	0	0	0	0	2,989	2,667	1,579	763	0	0	0	0	0	0	0
DeWitt	2,151	1,977	1,773	1,569	1,354	1,130	907	684	460	237	14	1,721	1,407	1,065	924	780	638	500	369	243	122	7
Dickens	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dimmit	3,706	4,777	4,765	4,857	4,871	4,834	4,232	3,489	2,746	2,002	1,259	2,965	3,407	2,828	2,774	2,669	2,534	2,145	1,710	1,294	895	516
Donley	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Duval	0	70	94	117	118	103	87	72	57	42	27	0	53	59	73	72	61	51	41	32	23	14
Eastland	0	0	424	642	550	458	367	275	184	92	0	0	0	318	465	385	309	238	172	110	53	0
Ector	756	983	1,340	1,434	1,529	1,484	1,309	1,134	959	784	644	514	524	469	478	488	451	390	332	274	219	176
Edwards	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ellis	38	87	126	166	206	185	164	144	123	103	82	35	74	95	120	144	125	107	90	74	59	45
El Paso	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Erath	12	163	253	343	433	397	361	325	289	253	217	11	137	190	249	303	268	235	203	173	145	119
Falls	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fannin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fayette	132	1,081	2,329	2,093	1,822	1,526	1,229	932	636	340	43	106	773	1,402	1,236	1,054	864	681	505	337	176	23
Fisher	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Floyd	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Foard	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fort Bend	0	35	46	58	58	51	43	36	28	21	14	0	26	29	36	35	30	25	20	16	11	7
Franklin	14	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	0	0
Freestone	424	750	975	1,229	1,424	1,404	1,241	1,076	912	748	584	339	678	846	1,042	1,196	1,164	1,012	863	720	582	449
Frio	729	1,119	1,146	1,176	1,189	1,159	1,127	1,097	947	769	589	583	809	701	708	692	647	602	559	465	364	266
Gaines	142	830	1,273	1,709	1,881	1,841	1,582	1,323	1,064	805	599	96	443	445	563	588	542	456	372	290	212	152
Galveston	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Garza	1	237	315	394	473	426	379	331	284	237	189	0	126	110	136	160	141	123	106	89	72	57
Gillespie	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Glasscock	1,434	1,938	2,621	2,466	2,311	1,978	1,646	1,313	980	648	427	975	1,033	917	848	780	655	535	419	306	198	128
Goliad	0	34	45	56	56	49	42	35	27	20	13	0	25	28	35	34	29	24	20	15	11	7
Gonzales	2,224	1,746	1,552	1,358	1,164	970	776	582	388	194	0	1,779	1,241	931	798	669	545	427	313	204	99	0
Gray	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Grayson	21	0	0	0	0	0	0	0	0	0	0	20	0	0	0	0	0	0	0	0	0	0
Gregg	25	134	224	313	402	449	405	362	318	274	230	24	127	208	284	357	391	347	305	263	223	184
Grimes	95	125	287	448	569	506	443	380	317	254	191	76	94	178	270	334	291	249	209	170	133	97
Guadalupe	18	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	0	0
Hale	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hamilton	0	251	304	253	203	152	101	51	0	0	0	0	212	228	184	142	103	66	32	0	0	0
Hansford	11	0	513	1,025	879	732	586	439	293	146	0	5	0	205	397	329	265	205	148	95	46	0
Hardeman	17	0	0	0	0	0	0	0	0	0	0	12	0	0	0	0	0	0	0	0	0	0
Hardin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Harris	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Harrison	893	1,578	2,223	2,012	1,851	1,689	1,527	1,365	1,203	1,041	880	849	1,479	2,030	1,808	1,636	1,469	1,307	1,149	996	847	704

	Water Use (AF)											Water Consumption (AF)										
County	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**
Hartley	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Haskell	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hays	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hemphill	1,462	2,484	2,231	1,978	1,724	1,470	1,217	963	710	456	203	731	1,132	892	766	646	533	426	325	231	143	61
Henderson	12	46	124	201	278	333	296	259	222	185	148	12	44	117	187	254	297	259	222	186	151	118
Hidalgo	59	63	83	104	105	91	78	64	51	37	24	47	47	53	65	64	54	45	37	28	20	13
Hill	131	1,429	1,225	1,021	816	612	408	204	0	0	0	120	1,207	919	740	571	413	265	128	0	0	0
Hockley	5	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0
Hood	645	409	580	751	921	829	737	645	553	461	369	593	346	435	544	645	560	479	403	332	265	203
Hopkins	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Houston	178	237	305	271	237	203	170	135	102	68	34	142	179	193	168	144	121	99	77	57	37	18
Howard	552	1,471	2,360	2,822	2,642	2,250	1,859	1,468	1,076	685	422	376	784	826	970	892	745	604	468	336	210	126
Hudspeth	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hunt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hutchinson	5	0	90	180	154	128	103	77	51	26	0	2	0	36	70	58	47	36	26	17	8	0
Irion	875	1,478	2,429	2,889	2,613	2,190	1,766	1,343	920	497	221	595	788	850	993	882	725	574	428	287	152	66
Jack	48	242	363	485	605	545	485	424	363	303	242	44	204	273	351	424	368	315	265	218	174	133
Jackson	0	34	45	56	56	49	42	35	28	20	13	0	25	29	35	34	29	25	20	15	11	7
Jasper	87	105	135	120	105	90	75	60	45	30	15	83	79	86	75	64	54	44	34	25	16	8
Jeff Davis	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jefferson	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jim Hogg	0	45	60	75	75	65	56	46	37	27	17	0	34	38	46	46	39	32	26	20	15	9
Jim Wells	0	34	45	57	57	50	42	35	28	21	13	0	26	29	35	35	30	25	20	15	11	7
Johnson	4,192	4,038	3,365	2,692	2,019	1,346	673	0	0	0	0	3,857	3,410	2,524	1,952	1,413	909	437	0	0	0	0
Jones	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Karnes	3,869	2,749	2,457	2,165	1,863	1,554	1,245	937	629	320	11	3,095	1,956	1,475	1,273	1,073	876	686	505	331	165	6
Kaufman	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kendall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kenedy	6	57	76	95	95	83	71	58	46	34	22	5	43	48	59	58	49	41	33	26	19	12
Kent	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kerr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kimble	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
King	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kinney	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kleberg	34	37	49	62	62	54	46	38	30	22	14	28	28	31	38	38	32	27	22	17	12	8
Knox	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lampasas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
La Salle	2,901	4,432	4,425	4,532	4,621	4,698	4,147	3,440	2,732	2,025	1,318	2,321	3,154	2,612	2,563	2,499	2,427	2,070	1,659	1,265	889	530
Lavaca	118	913	1,522	1,388	1,241	1,086	930	775	620	464	309	94	651	915	818	716	613	513	418	326	239	155
Lee	131	203	392	508	624	553	484	414	345	274	204	105	152	243	305	365	316	270	226	184	142	103
Leon	273	663	1,289	1,800	2,309	2,192	1,934	1,674	1,416	1,155	898	218	487	831	1,166	1,487	1,415	1,225	1,041	864	693	529
Liberty	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Limestone	268	307	347	388	410	376	332	287	242	197	153	214	281	307	333	346	312	270	229	190	153	116
Lipscomb	382	560	1,026	876	725	574	423	272	121	0	0	191	255	410	339	272	208	148	92	39	0	0
Live Oak	972	783	729	676	692	720	748	776	689	575	461	777	558	439	399	392	388	384	379	324	261	200
Llano	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Loving	189	313	418	561	704	690	627	565	502	439	376	38	167	146	187	227	213	191	169	147	127	107
Lubbock	0	0	0	51	103	154	140	126	112	98	84	0	0	0	10	21	31	28	25	22	20	17
Lynn	0	0	246	336	427	517	460	402	345	287	230	0	0	86	116	144	171	149	128	108	88	69
McCulloch	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
McLennan	0	53	120	187	253	228	203	177	152	127	101	0	45	90	135	177	154	132	111	91	73	56
McMullen	1,752	2,545	2,762	3,067	3,329	3,562	3,306	2,930	2,553	2,177	1,801	1,401	1,815	1,627	1,729	1,797	1,840	1,658	1,430	1,211	1,001	801
Madison	204	261	561	750	940	832	727	622	518	413	308	163	197	348	451	549	475	406	339	275	214	155
Marion	10	121	270	420	569	579	522	466	408	351	295	10	114	249	380	506	506	449	393	339	286	236
Martin	2,035	2,446	3,071	2,824	2,577	2,267	1,892	1,516	1,141	765	512	1,384	1,305	1,075	963	855	731	597	468	344	224	145
Mason	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Matagorda	0	46	61	77	77	67	57	47	37	28	18	0	35	39	48	47	40	33	27	21	15	9
Maverick	192	1,574	1,857	2,241	2,626	3,010	2,843	2,538	2,234	1,928	1,623	154	1,119	1,074	1,226	1,368	1,501	1,376	1,195	1,022	856	698
Medina	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Menard	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Midland	1,573	2,640	3,265	3,034	2,803	2,465	2,045	1,625	1,205	785	488	1,070	1,408	1,143	1,034	928	791	643	499	361	227	136
Milam	34	0	0	0	0	0	0	0	0	0	0	27	0	0	0	0	0	0	0	0	0	0
Mills	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mitchell	18	238	317	397	476	428	381	333	286	238	190	12	127	111	136	161	142	124	106	89	73	57
Montague	3,221	3,496	2,997	2,497	1,998	1,498	999	499	0	0	0	2,963	2,952	2,248	1,810	1,398	1,011	649	312	0	0	0
Montgomery	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Moore	76	0	0	0	0	0	0	0	0	0	0	38	0	0	0	0	0	0	0	0	0	0
Morris	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Motley	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nacogdoches	1,128	1,424	2,066	1,937	1,809	1,659	1,503	1,347	1,191	1,036	880	1,072	1,327	1,873	1,731	1,593	1,438	1,283	1,132	985	842	704
Navarro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Newton	98	125	161	143	125	108	89	71	54	36	18	93	94	102	89	76	64	52	41	30	20	9
Nolan	11	0	0	0	0	0	0	0	0	0	0	8	0	0	0	0	0	0	0	0	0	0
Nueces	16	34	45	56	56	49	42	35	28	20	13	13	25	29	35	34	29	25	20	15	11	7
Ochiltree	273	408	748	985	815	646	476	306	136	0	0	136	186	299	382	306	234	166	103	44	0	0
Oldham	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Orange	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Palo Pinto	41	194	356	518	680	612	544	476	408	340	272	38	164	267	376	476	413	354	298	245	196	150
Panola	966	1,412	1,988	1,801	1,655	1,511	1,366	1,221	1,077	932	787	917	1,323	1,816	1,618	1,464	1,314	1,169	1,028	891	758	630
Parker	1,086	925	1,255	1,585	1,916	1,724	1,533	1,341	1,149	958	766	1,000	781	941	1,149	1,341	1,164	996	838	690	551	421
Parmer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pecos	110	130	173	387	601	746	674	601	528	456	383	22	69	60	108	156	180	161	142	123	105	87
Polk	133	180	232	206	180	155	129	103	77	52	26	126	136	147	128	110	92	75	59	43	28	14
Potter	44	0	0	0	0	0	0	0	0	0	0	22	0	0	0	0	0	0	0	0	0	0
Presidio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Randall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reagan	1,240	3,207	4,019	3,627	3,236	2,844	2,332	1,820	1,308	796	444	843	1,710	1,407	1,247	1,092	942	758	580	409	244	133
Real	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Red River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reeves	522	866	1,155	1,744	2,333	2,509	2,304	2,098	1,893	1,687	1,481	104	462	404	556	705	713	646	581	518	456	395
Refugio	0	32	42	53	53	46	39	33	26	19	12	0	24	27	33	32	27	23	19	14	10	7
Roberts	393	1,628	1,419	1,210	1,002	793	584	376	167	0	0	197	742	568	469	376	287	205	127	54	0	0
Robertson	306	587	741	773	806	734	639	544	449	354	259	245	501	587	619	648	584	500	419	342	268	196
Rockwall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Runnels	4	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0
Rusk	158	477	930	1,384	1,838	1,707	1,542	1,378	1,213	1,048	884	150	446	850	1,245	1,627	1,487	1,322	1,161	1,005	853	707
Sabine	147	235	470	705	940	861	783	705	627	548	470	139	218	423	625	823	743	666	590	517	445	376
San Augustine	1,622	2,092	1,953	1,814	1,674	1,534	1,395	1,256	1,116	977	837	1,541	1,941	1,758	1,610	1,465	1,323	1,186	1,052	921	793	670
San Jacinto	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
San Patricio	0	28	37	46	46	40	34	28	22	17	11	0	21	23	28	28	24	20	16	13	9	6

	Water Use (AF)											Water Consumption (AF)										
County	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**	**2011**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**	**2060**
San Saba	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Schleicher	90	312	468	568	584	507	430	354	277	200	140	61	166	164	195	197	168	140	113	87	61	42
Scurry	10	0	249	341	432	524	466	408	349	291	233	7	0	87	117	146	174	151	130	109	89	70
Shackelford	2	0	156	311	467	421	374	327	280	234	187	2	0	117	226	327	284	243	204	168	134	103
Shelby	1,419	1,658	3,073	2,929	2,785	2,621	2,377	2,133	1,889	1,645	1,400	1,348	1,539	2,771	2,607	2,446	2,270	2,027	1,790	1,561	1,337	1,120
Sherman	2	0	0	92	184	158	132	105	79	53	26	1	0	0	36	69	57	46	36	26	16	8
Smith	5	18	49	80	111	133	118	103	88	74	59	5	17	47	75	101	118	103	88	74	60	47
Somervell	287	184	260	336	413	372	330	289	248	207	165	264	155	195	244	289	251	215	181	149	119	91
Starr	36	48	64	79	79	69	59	49	39	29	18	29	36	40	49	48	41	35	28	22	16	10
Stephens	0	52	184	315	447	402	357	312	268	223	179	0	44	138	229	313	271	232	195	161	128	98
Sterling	57	265	707	881	893	905	765	625	484	344	236	39	141	248	303	302	300	249	199	151	105	71
Stonewall	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sutton	34	0	390	534	677	821	730	639	547	456	365	23	0	137	183	229	272	237	204	171	140	109
Swisher	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tarrant	8,805	6,836	5,469	4,101	2,734	1,367	0	0	0	0	0	8,101	5,773	4,102	2,974	1,914	923	0	0	0	0	0
Taylor	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Terrell	10	0	162	221	281	341	303	265	227	189	151	7	0	57	76	95	113	98	84	71	58	45
Terry	3	0	243	332	422	511	454	397	341	284	227	2	0	85	114	142	169	148	127	106	87	68
Throckmorton	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Titus	3	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0
Tom Green	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Travis	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trinity	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tyler	76	110	147	184	185	161	137	114	90	66	42	72	83	93	114	113	96	80	65	50	36	23
Upshur	4	57	247	437	627	764	690	617	543	469	396	4	54	226	393	555	665	591	519	449	382	316
Upton	1,761	2,955	3,728	3,442	3,156	2,870	2,398	1,927	1,455	983	664	1,198	1,576	1,305	1,171	1,041	916	749	588	433	283	185
Uvalde	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Val Verde	0	0	80	110	139	168	150	131	112	94	75	0	0	28	38	47	56	49	42	35	29	22
Van Zandt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Victoria	0	35	46	58	58	51	43	36	28	21	14	0	26	29	36	35	30	25	20	16	11	7
Walker	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Waller	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ward	568	568	683	888	871	855	764	672	581	489	398	114	568	239	297	278	260	228	197	167	138	110
Washington	36	0	497	878	798	718	638	559	479	399	319	29	0	298	516	459	404	351	300	251	204	160
Webb	4,596	3,661	3,476	3,052	2,626	2,244	1,872	1,501	1,128	699	255	3,677	2,627	2,109	1,814	1,529	1,274	1,033	803	580	344	113
Wharton	0	43	57	71	72	62	53	44	35	26	17	0	32	36	44	43	37	31	25	20	14	9
Wheeler	3,792	3,524	3,072	2,620	2,168	1,717	1,265	813	362	0	0	1,896	1,605	1,229	1,015	813	622	443	274	117	0	0
Wichita	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wilbarger	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Willacy	0	23	31	39	39	34	29	24	19	14	9	0	18	20	24	24	20	17	14	11	8	5
Williamson	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wilson	417	1,612	1,865	1,679	1,492	1,306	1,119	932	746	560	373	334	1,146	1,119	986	858	734	615	501	392	287	187
Winkler	62	464	618	821	1,024	979	873	767	661	556	450	12	247	216	275	332	305	267	231	195	160	127
Wise	2,314	2,757	2,450	2,144	1,838	1,531	1,225	919	613	306	0	2,129	2,328	1,838	1,555	1,287	1,034	796	574	368	176	0
Wood	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Yoakum	18	238	330	423	384	346	308	269	230	192	154	13	127	116	145	130	115	100	86	72	59	46
Young	8	0	78	157	235	211	188	164	141	118	94	7	0	59	113	164	143	122	103	85	68	52
Zapata	32	41	55	68	68	60	51	42	33	25	16	26	31	35	42	42	35	30	24	19	13	8
Zavala	407	2,065	2,427	2,280	2,167	2,035	1,904	1,773	1,502	1,197	891	326	1,477	1,465	1,351	1,247	1,132	1,020	912	747	575	410
SUM (kAF)	**81.5**	**110**	**132**	**135**	**134**	**122**	**104**	**87**	**70**	**53**	**39**	**64.8**	**78.2**	**76.9**	**76.0**	**72.8**	**64.2**	**53.2**	**43.4**	**34.4**	**26.3**	**19.1**

MiningWaterUse2010-2060_5.xls

Table 16. County-level estimate of 2012-2060 projections for oil and gas water use and water consumption (AF).

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
Anderson	39	129	140	157	177	181	185	169	147	126	105	67	87	88	98	109	115	121	109	93	78	63
Andrews	3,212	3,481	3,959	3,833	3,710	3,511	3,177	2,842	2,509	2,192	1,929	1,868	1,231	1,029	921	819	742	640	544	453	372	311
Angelina	0	116	220	316	412	427	389	351	312	274	237	32	112	203	286	366	374	336	299	263	228	195
Aransas	0	12	10	8	7	5	5	5	5	5	5	10	11	10	8	6	5	5	5	5	5	5
Archer	30	351	405	444	483	389	344	311	279	246	213	239	326	337	343	344	252	222	194	167	142	119
Armstrong	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Atascosa	1,012	2,993	2,770	2,713	2,706	2,700	2,693	2,393	2,021	1,649	1,279	867	2,155	1,711	1,618	1,551	1,484	1,415	1,219	1,000	790	590
Austin	0	28	127	224	320	288	257	226	194	163	132	20	29	88	143	195	173	151	130	110	91	73
Bailey	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bandera	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bastrop	0	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Baylor	1	14	14	14	14	14	13	13	13	13	13	12	12	12	12	12	12	12	12	12	13	13
Bee	66	111	127	129	112	95	80	67	53	40	26	92	90	89	87	74	62	52	44	36	28	20
Bell	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bexar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Blanco	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Borden	27	272	679	926	927	929	784	639	494	352	244	72	165	263	339	331	323	267	214	164	117	82
Bosque	0	470	557	627	696	579	516	466	416	365	315	238	439	462	485	502	387	340	296	255	216	180
Bowie	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brazoria	0	91	102	113	125	114	100	88	76	64	52	42	80	78	82	86	76	67	59	52	45	38
Brazos	238	364	741	975	1,207	1,072	938	804	670	536	402	266	286	477	602	721	628	538	451	368	287	211
Brewster	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Briscoe	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Brooks	27	70	77	84	80	69	60	52	44	36	28	50	60	58	60	55	47	41	36	31	26	22
Brown	23	35	34	34	33	32	31	30	29	28	27	17	16	14	14	14	14	14	14	14	14	14
Burleson	247	380	995	1,459	1,923	1,717	1,512	1,306	1,100	892	686	279	299	632	890	1,135	993	855	723	595	471	354
Burnet	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Caldwell	75	98	123	111	98	85	72	59	46	33	20	82	75	81	71	62	54	45	37	29	22	14
Calhoun	18	48	52	57	55	47	41	35	30	25	19	34	41	39	41	38	32	28	24	21	18	15
Callahan	84	93	88	88	87	83	79	74	70	66	62	29	24	18	17	16	15	15	15	15	15	15
Cameron	27	58	65	72	68	57	47	39	31	23	15	38	47	45	48	43	34	28	23	18	13	9
Camp	13	12	12	11	11	11	10	9	9	8	8	2	2	1	1	1	0	0	0	0	0	0
Carson	2	14	14	14	14	14	14	14	14	14	14	13	13	13	13	13	13	13	13	13	13	13
Cass	1	30	39	48	58	68	60	52	45	37	30	26	28	36	44	52	60	52	45	38	31	24
Castro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Chambers	0	9	9	9	9	9	9	9	9	9	9	8	9	9	9	9	9	9	9	9	9	9
Cherokee	10	129	172	216	263	299	267	236	204	173	141	80	123	163	201	239	269	236	204	173	144	116
Childress	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Clay	63	508	613	699	786	655	584	527	471	414	357	318	472	506	538	563	435	382	333	286	243	202
Cochran	56	128	154	181	208	234	210	187	163	139	115	46	64	54	63	71	79	70	62	54	46	38
Coke	520	511	484	480	477	451	425	397	370	346	322	114	84	46	40	33	32	31	29	28	27	26
Coleman	100	113	108	107	107	102	97	91	86	82	77	37	31	24	23	22	21	21	21	21	21	20
Collin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Collingsworth	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Colorado	28	129	608	1,078	1,534	1,376	1,221	1,067	913	759	605	86	120	402	667	913	802	697	596	499	406	317
Comal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Comanche	2	388	444	485	525	419	363	319	276	232	188	224	366	374	379	380	278	240	204	170	138	109
Concho	515	507	480	477	474	448	422	394	367	343	320	114	84	46	40	34	33	31	30	29	28	27
Cooke	1,493	1,708	1,343	978	612	246	28	27	26	25	24	1,391	1,434	1,001	702	421	158	13	13	13	13	13
Coryell	0	569	1,238	1,102	767	434	158	0	0	0	0	236	522	972	827	548	284	103	0	0	0	0

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
Cottle	32	43	41	41	41	39	38	36	34	33	31	18	16	14	14	13	13	13	13	13	13	13
Crane	280	508	617	728	840	947	861	776	692	610	531	227	246	225	249	273	299	265	232	201	174	149
Crockett	507	1,097	1,732	2,035	1,843	1,552	1,261	971	682	394	207	553	606	641	730	650	539	434	332	235	143	85
Crosby	1,083	1,050	994	987	980	926	871	814	757	706	656	224	161	82	69	55	53	50	47	45	43	40
Culberson	279	293	506	873	1,240	1,535	1,393	1,250	1,110	972	843	151	97	249	308	371	415	368	323	279	240	208
Dallam	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dallas	79	726	1,076	888	700	512	339	170	0	0	0	134	624	818	651	493	343	220	106	0	0	0
Dawson	268	695	954	1,137	1,164	1,184	1,023	862	703	546	423	165	323	328	371	360	353	296	241	189	140	104
Deaf Smith	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Delta	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Denton	3,249	3,297	2,220	1,136	51	19	13	13	13	13	13	3,108	2,805	1,688	840	44	13	13	13	13	13	13
DeWitt	2,177	2,061	1,858	1,646	1,421	1,188	958	729	500	271	42	1,801	1,493	1,149	999	846	694	550	413	281	155	35
Dickens	0	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	13
Dimmit	3,708	4,874	4,919	5,001	5,001	4,952	4,337	3,580	2,824	2,068	1,315	3,068	3,506	2,980	2,913	2,795	2,648	2,246	1,797	1,368	958	569
Donley	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Duval	52	133	147	160	153	131	114	99	84	69	54	96	114	110	114	105	89	77	68	58	50	41
Eastland	333	578	937	1,091	934	764	644	535	425	318	211	286	303	539	619	472	335	263	196	133	75	21
Ector	845	1,144	1,537	1,612	1,690	1,628	1,435	1,245	1,056	870	725	850	612	588	577	570	520	447	377	310	251	206
Edwards	0	28	29	29	29	29	29	29	29	29	29	28	28	29	29	29	29	29	29	29	29	29
Ellis	38	112	147	180	213	186	164	144	123	103	82	56	99	114	133	150	125	107	90	74	59	45
El Paso	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Erath	12	470	505	521	536	426	376	340	304	268	232	274	443	427	411	391	283	250	218	188	161	134
Falls	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fannin	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fayette	132	1,149	2,403	2,164	1,887	1,585	1,282	979	677	375	72	166	844	1,476	1,306	1,118	922	733	551	377	210	51
Fisher	432	426	403	401	398	376	355	332	309	289	269	97	71	40	35	30	28	27	26	25	24	24
Floyd	148	156	148	147	146	139	131	123	116	109	102	42	34	23	21	19	19	19	18	18	18	17
Foard	3	12	12	12	12	12	12	12	12	12	11	10	10	10	10	10	10	10	10	10	10	10
Fort Bend	25	66	72	79	75	65	56	49	41	34	27	47	56	54	56	52	44	38	33	29	24	20
Franklin	5	5	5	5	5	5	4	4	4	3	3	1	1	0	0	0	0	0	0	0	0	0
Freestone	429	929	1,117	1,331	1,494	1,458	1,291	1,121	954	785	618	600	844	975	1,133	1,254	1,213	1,056	903	757	615	479
Frio	729	1,167	1,217	1,243	1,250	1,215	1,178	1,142	986	804	620	666	858	772	774	752	702	652	603	504	398	296
Gaines	124	914	1,429	1,846	2,000	1,945	1,671	1,398	1,127	859	651	190	517	590	686	694	635	533	436	344	259	197
Galveston	0	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Garza	53	321	395	469	544	491	438	386	334	284	234	44	166	144	164	184	162	142	122	104	87	71
Gillespie	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Glasscock	1,838	2,402	3,057	2,887	2,718	2,355	1,994	1,634	1,275	921	681	1,590	1,165	1,010	923	839	704	575	452	334	224	153
Goliad	25	64	70	77	73	63	54	47	40	33	26	46	55	53	55	50	42	37	32	28	24	20
Gonzales	2,164	1,791	1,600	1,405	1,207	1,010	813	616	418	221	24	1,764	1,288	980	844	712	585	463	346	233	126	23
Gray	68	78	75	74	74	70	67	63	60	57	53	26	22	17	16	15	15	15	15	15	15	15
Grayson	6	19	18	18	18	18	18	18	17	17	17	14	14	14	14	14	14	14	14	14	14	14
Gregg	25	191	274	353	433	476	429	383	337	292	246	71	182	256	322	387	418	371	326	282	240	199
Grimes	95	159	323	483	602	537	471	405	340	275	209	120	129	214	305	367	321	276	233	192	153	115
Guadalupe	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Hale	1,289	1,235	1,168	1,160	1,152	1,087	1,022	954	886	826	766	252	177	82	67	51	48	45	42	39	36	33
Hall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hamilton	0	361	393	314	236	157	101	51	0	0	0	93	321	312	239	169	103	66	32	0	0	0
Hansford	13	88	577	1,068	904	749	602	456	309	162	16	68	79	261	432	348	278	218	161	108	59	13
Hardeman	0	9	9	9	9	10	10	10	10	10	10	9	9	9	9	9	10	10	10	10	10	10
Hardin	0	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Harris	0	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Harrison	868	1,763	2,388	2,145	1,956	1,778	1,608	1,438	1,268	1,098	930	1,021	1,658	2,189	1,935	1,735	1,557	1,386	1,219	1,059	903	753

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
Hartley	7	7	7	7	7	6	6	6	5	5	4	1	1	0	0	0	0	0	0	0	0	0
Haskell	90	98	93	93	92	88	83	79	74	70	66	30	25	18	17	16	16	15	15	15	15	15
Hays	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hemphill	1,441	2,567	2,314	2,037	1,763	1,499	1,244	988	732	476	223	1,498	1,209	971	821	683	562	452	349	252	163	80
Henderson	3	120	176	235	296	346	308	272	235	198	161	91	113	166	218	269	310	272	235	199	164	131
Hidalgo	46	119	130	143	136	117	101	88	74	61	48	85	101	98	102	94	79	69	60	52	44	37
Hill	131	1,572	1,343	1,106	869	632	422	218	13	14	14	244	1,349	1,031	819	617	427	279	141	13	14	14
Hockley	6	18	18	18	18	17	17	17	17	16	16	13	13	13	13	13	13	13	13	13	13	13
Hood	645	529	678	820	961	841	743	651	559	467	375	695	465	528	608	679	566	485	409	338	271	209
Hopkins	42	41	38	38	38	36	34	31	29	27	25	8	6	3	2	2	2	1	1	1	1	1
Houston	178	254	322	287	254	220	187	152	119	85	51	195	196	210	185	161	138	116	94	74	54	35
Howard	619	1,611	2,491	2,939	2,747	2,343	1,940	1,538	1,138	742	476	643	870	898	1,028	938	782	633	490	354	226	142
Hudspeth	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hunt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hutchinson	21	51	156	237	204	173	144	115	86	58	30	32	34	85	110	90	75	62	50	39	28	20
Irion	1,677	2,286	3,192	3,643	3,357	2,890	2,423	1,955	1,487	1,026	713	1,070	937	937	1,065	940	778	621	471	327	190	102
Jack	17	501	575	635	693	572	499	438	378	317	256	232	459	470	487	497	381	328	278	231	187	146
Jackson	25	64	70	77	73	63	55	47	40	33	26	46	55	53	55	51	43	37	32	28	24	20
Jasper	87	118	148	133	118	103	88	73	58	43	28	100	92	98	88	77	67	57	47	38	30	21
Jeff Davis	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jefferson	0	13	13	13	13	14	14	14	14	14	14	13	13	13	13	13	14	14	14	14	14	14
Jim Hogg	33	85	93	102	97	83	72	63	53	44	34	61	73	70	73	67	56	49	43	37	31	26
Jim Wells	25	65	71	78	74	64	55	48	40	33	26	46	55	53	55	51	43	37	33	28	24	20
Johnson	4,192	4,240	3,530	2,809	2,086	1,365	683	10	10	10	10	4,029	3,611	2,680	2,059	1,471	918	447	10	10	10	10
Jones	117	125	119	118	117	111	106	99	93	88	82	35	29	20	19	17	17	17	16	16	16	16
Karnes	3,882	2,820	2,528	2,229	1,919	1,603	1,288	975	662	349	35	3,155	2,028	1,545	1,336	1,127	923	728	542	363	192	29
Kaufman	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kendall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kenedy	42	108	118	130	123	106	92	80	68	55	43	78	92	89	92	85	72	62	55	47	40	33
Kent	29	39	38	38	38	36	35	33	32	31	29	18	16	14	14	13	13	13	13	13	13	13
Kerr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kimble	0	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17	17
King	8,635	8,287	7,836	7,783	7,730	7,293	6,857	6,402	5,946	5,545	5,144	1,704	1,198	565	461	357	334	311	291	271	253	236
Kinney	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Kleberg	27	70	77	84	80	69	60	52	44	36	28	51	60	58	60	55	47	41	36	31	26	22
Knox	3	15	15	15	15	14	14	14	14	14	14	12	12	12	12	12	12	12	12	12	12	12
Lamar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lamb	647	620	586	582	579	546	513	479	445	415	385	127	89	41	34	26	24	22	21	19	18	17
Lampasas	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
La Salle	2,889	4,569	4,617	4,705	4,772	4,830	4,263	3,541	2,819	2,098	1,380	2,408	3,293	2,801	2,731	2,647	2,556	2,183	1,757	1,349	959	590
Lavaca	145	1,003	1,613	1,470	1,313	1,148	985	824	662	501	340	179	742	1,005	898	786	673	567	465	368	274	184
Lee	132	230	421	536	650	577	506	435	363	290	218	151	179	272	333	390	340	292	246	201	158	117
Leon	327	847	1,482	1,983	2,481	2,349	2,077	1,802	1,530	1,256	985	361	629	977	1,301	1,611	1,527	1,325	1,129	941	758	584
Liberty	0	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
Limestone	271	383	402	424	431	391	347	302	257	212	167	356	350	355	363	361	325	283	242	203	166	129
Lipscomb	387	656	1,098	926	758	597	446	294	142	21	21	434	335	467	375	290	221	161	105	52	13	13
Live Oak	1,002	851	814	751	757	776	798	820	729	610	492	853	627	523	473	455	443	433	422	363	294	230
Llano	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Loving	542	691	792	925	1,058	1,020	934	848	762	681	601	300	256	223	251	279	259	229	202	175	152	131
Lubbock	6,211	5,963	5,663	5,673	5,684	5,419	5,089	4,745	4,401	4,097	3,794	1,228	865	433	365	298	290	268	249	229	212	196
Lynn	981	974	1,166	1,246	1,327	1,365	1,255	1,144	1,033	929	826	226	168	179	192	205	227	200	175	150	128	107
McCulloch	42	40	38	38	38	35	33	31	29	27	25	8	6	3	2	2	2	1	1	1	1	1

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
McLennan	0	194	234	265	296	235	203	177	152	127	101	119	185	197	206	212	154	132	111	91	73	56
McMullen	1,720	2,653	2,912	3,203	3,448	3,666	3,398	3,010	2,622	2,235	1,850	1,465	1,924	1,775	1,860	1,911	1,941	1,746	1,507	1,276	1,056	848
Madison	204	295	597	785	972	861	754	646	538	430	323	227	231	384	485	581	504	432	362	295	231	169
Marion	5	208	348	483	619	622	561	501	440	379	319	73	196	322	438	552	546	485	425	368	312	258
Martin	2,435	2,906	3,527	3,262	2,998	2,657	2,251	1,845	1,441	1,043	771	2,190	1,435	1,191	1,059	933	796	651	513	380	257	177
Mason	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Matagorda	34	87	96	105	100	86	75	64	55	45	35	63	75	72	75	69	58	51	44	38	32	27
Maverick	174	1,652	1,988	2,364	2,737	3,111	2,933	2,617	2,302	1,986	1,674	188	1,196	1,201	1,342	1,474	1,597	1,461	1,269	1,085	910	744
Medina	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Menard	1,185	1,148	1,086	1,079	1,071	1,012	952	889	827	772	717	244	175	88	74	59	56	53	50	48	45	43
Midland	1,719	2,876	3,522	3,272	3,025	2,666	2,227	1,788	1,350	918	612	1,661	1,506	1,256	1,127	1,005	855	695	542	395	257	164
Milam	0	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Mills	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mitchell	27	284	361	435	511	460	409	358	309	259	211	50	162	142	163	184	162	141	122	103	86	70
Montague	3,233	3,776	3,228	2,665	2,102	1,538	1,026	525	25	24	24	3,186	3,216	2,452	1,950	1,474	1,025	663	326	14	14	14
Montgomery	0	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
Moore	4	16	16	16	16	16	16	15	15	15	15	13	13	13	12	12	12	13	13	13	13	13
Morris	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Motley	130	138	132	131	130	123	117	110	103	97	91	39	31	22	20	19	18	18	18	18	17	17
Nacogdoches	1,073	1,642	2,299	2,141	1,986	1,815	1,643	1,471	1,299	1,128	958	1,220	1,550	2,101	1,930	1,764	1,591	1,420	1,251	1,089	932	779
Navarro	11	25	24	24	24	24	23	23	22	22	21	17	16	15	15	15	15	15	15	15	15	15
Newton	98	138	173	156	138	120	102	84	67	49	31	111	107	115	102	89	77	65	54	43	33	23
Nolan	214	218	207	205	204	193	182	171	160	150	140	54	42	26	24	21	21	20	20	19	19	18
Nueces	25	64	70	77	73	63	55	47	40	33	26	46	55	53	55	51	43	37	32	28	24	20
Ochiltree	286	508	824	1,040	853	674	503	332	161	24	23	329	266	355	418	325	247	180	116	57	13	13
Oldham	15	14	13	13	13	12	12	11	10	9	9	3	2	1	1	1	1	1	0	0	0	0
Orange	0	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Palo Pinto	120	547	656	752	847	709	625	552	480	408	336	281	446	483	524	557	430	370	314	261	212	165
Panola	958	1,578	2,136	1,919	1,749	1,590	1,438	1,286	1,134	983	832	1,095	1,484	1,959	1,731	1,552	1,392	1,240	1,091	948	808	674
Parker	1,083	1,180	1,464	1,733	2,001	1,748	1,545	1,353	1,162	970	779	1,215	1,035	1,139	1,284	1,414	1,176	1,009	851	702	563	434
Parmer	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pecos	409	543	690	878	1,068	1,180	1,072	966	861	762	672	274	227	313	331	353	359	320	283	249	220	198
Polk	133	195	247	221	195	170	144	118	92	67	41	148	151	162	143	125	107	90	74	58	43	29
Potter	2	14	14	14	14	14	14	14	14	14	14	13	13	13	13	13	13	13	13	13	13	13
Presidio	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rains	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Randall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reagan	1,350	3,414	4,211	3,802	3,395	2,985	2,457	1,931	1,406	886	529	1,361	1,825	1,501	1,323	1,153	991	796	610	432	265	155
Real	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Red River	4	4	4	4	4	4	3	3	3	3	3	1	1	0	0	0	0	0	0	0	0	0
Reeves	611	1,111	1,520	2,067	2,619	2,761	2,522	2,285	2,052	1,827	1,614	701	632	688	796	908	888	791	700	615	541	477
Refugio	23	60	66	72	69	59	51	44	38	31	24	43	51	49	51	47	40	35	30	26	22	18
Roberts	365	1,711	1,502	1,270	1,041	822	611	400	189	20	20	423	819	647	524	412	316	231	151	76	20	20
Robertson	305	691	813	817	826	746	651	556	461	366	271	431	599	654	657	664	595	512	431	354	279	208
Rockwall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Runnels	285	287	272	271	269	255	240	225	210	197	184	70	53	32	29	26	25	24	24	23	22	22
Rusk	210	719	1,149	1,569	1,994	1,844	1,668	1,492	1,316	1,141	967	323	637	1,017	1,377	1,730	1,578	1,404	1,234	1,070	912	759
Sabine	147	331	584	809	1,035	946	858	770	682	595	508	196	319	536	728	915	826	739	653	571	491	413
San Augustine	1,584	2,198	2,077	1,928	1,779	1,628	1,479	1,330	1,180	1,032	884	1,642	2,052	1,880	1,722	1,567	1,415	1,268	1,124	983	847	715
San Jacinto	0	8	8	8	8	9	9	9	9	9	9	8	8	8	8	8	9	9	9	9	9	9
San Patricio	20	52	57	63	60	51	44	39	33	27	21	38	45	43	45	41	35	30	26	23	19	16

County	Water Use (AF)											Water Consumption (AF)										
	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060	2011	2015	2020	2025	2030	2035	2040	2045	2050	2055	2060
San Saba	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Schleicher	230	473	621	718	732	647	562	477	392	308	241	144	213	199	226	225	194	165	136	109	84	64
Scurry	3	34	280	368	456	544	483	423	363	304	246	37	33	118	143	169	193	168	145	123	102	83
Shackelford	219	464	562	655	747	628	558	500	442	385	328	264	285	329	373	409	305	263	224	187	153	121
Shelby	1,388	1,861	3,283	3,109	2,938	2,754	2,496	2,238	1,980	1,723	1,467	1,536	1,745	2,976	2,781	2,593	2,400	2,143	1,892	1,650	1,414	1,185
Sherman	9	42	35	121	207	178	151	124	98	71	44	28	33	26	55	84	70	59	48	39	29	21
Smith	20	91	107	125	145	163	147	131	115	100	84	67	71	85	100	117	132	117	102	88	74	61
Somervell	287	237	304	367	431	377	333	292	250	209	168	309	208	236	272	304	253	217	183	151	121	93
Starr	35	90	99	108	103	89	77	67	57	46	36	65	77	75	77	71	60	52	46	39	34	28
Stephens	5,158	5,248	5,064	5,103	5,141	4,775	4,458	4,141	3,825	3,541	3,257	1,226	1,004	663	630	591	476	423	374	328	285	244
Sterling	89	343	780	947	953	958	812	667	522	380	270	107	191	290	338	331	325	270	217	166	120	85
Stonewall	629	615	583	579	575	543	511	478	445	416	387	136	99	53	45	38	36	34	33	31	30	29
Sutton	33	59	446	582	720	858	763	668	573	481	389	81	53	185	225	264	303	264	227	192	160	130
Swisher	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tarrant	8,805	7,084	5,672	4,245	2,817	1,391	12	12	12	12	12	8,313	6,020	4,294	3,105	1,985	935	12	12	12	12	12
Taylor	71	81	77	77	76	73	69	65	62	58	55	26	22	17	16	15	15	15	15	15	15	14
Terrell	502	540	673	724	776	806	740	672	606	544	483	158	128	145	152	160	173	154	136	120	105	92
Terry	90	119	355	439	525	606	543	479	416	354	293	51	45	121	144	168	192	167	144	122	102	83
Throckmorton	200	204	194	193	191	181	171	161	150	141	132	52	40	25	23	20	20	19	19	19	18	18
Titus	8	8	7	7	7	7	6	6	5	5	5	2	1	1	0	0	0	0	0	0	0	0
Tom Green	53	72	69	69	68	66	63	60	58	55	53	31	28	24	24	23	23	23	23	23	23	23
Travis	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Trinity	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Tyler	78	123	160	197	198	174	150	127	103	79	55	91	96	106	127	125	109	93	78	63	49	36
Upshur	39	199	379	551	726	851	771	690	609	529	450	95	164	325	474	620	723	644	566	491	419	349
Upton	1,744	3,075	3,887	3,575	3,265	2,960	2,470	1,984	1,499	1,020	699	1,863	1,694	1,458	1,296	1,144	1,001	817	641	473	318	219
Uvalde	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Val Verde	0	66	144	169	195	221	199	179	158	139	120	67	66	91	97	102	108	98	89	81	74	68
Van Zandt	56	65	62	62	61	59	56	53	50	47	45	22	19	15	15	14	14	14	14	13	13	13
Victoria	25	66	72	79	75	65	56	49	41	34	27	47	56	54	56	52	44	38	33	29	24	20
Walker	0	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Waller	0	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Ward	582	632	775	968	941	915	815	716	617	521	429	622	620	317	362	333	307	267	229	193	161	132
Washington	0	44	545	924	840	757	673	589	506	422	338	30	46	346	561	500	442	385	330	277	227	178
Webb	4,599	3,878	3,708	3,257	2,804	2,397	2,007	1,623	1,238	796	341	3,948	2,844	2,337	2,014	1,701	1,422	1,166	922	687	439	196
Wharton	31	81	89	97	93	80	69	60	51	42	33	58	69	67	69	64	54	47	41	36	30	25
Wheeler	3,794	3,609	3,157	2,682	2,210	1,748	1,293	839	385	22	21	3,850	1,683	1,308	1,071	850	651	469	298	139	20	20
Wichita	59	65	62	62	61	58	55	52	49	46	44	20	17	12	12	11	11	11	11	10	10	10
Wilbarger	7	20	20	20	20	20	19	19	19	18	18	15	14	14	14	14	14	14	14	14	14	14
Willacy	17	44	49	53	51	44	38	33	28	23	18	32	38	37	38	35	29	26	22	19	17	14
Williamson	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wilson	418	1,671	1,929	1,740	1,548	1,357	1,165	973	782	590	399	373	1,206	1,182	1,045	912	783	659	540	426	315	210
Winkler	152	621	787	977	1,169	1,110	991	873	756	642	531	125	318	295	341	387	351	305	261	220	183	149
Wise	2,313	3,014	2,661	2,293	1,924	1,556	1,238	932	625	319	13	2,348	2,584	2,037	1,691	1,360	1,046	809	587	380	189	13
Wood	17	26	25	25	25	24	23	22	21	21	20	13	12	11	10	10	10	10	10	10	10	10
Yoakum	1,052	1,264	1,300	1,382	1,334	1,240	1,147	1,052	957	870	783	246	299	209	222	191	171	151	132	115	99	84
Young	15	142	197	244	291	236	206	183	159	135	111	125	136	165	188	208	156	135	116	97	81	65
Zapata	30	78	85	93	89	76	66	57	49	40	31	56	66	64	66	61	51	45	39	34	29	24
Zavala	407	2,140	2,531	2,379	2,257	2,118	1,977	1,838	1,559	1,245	932	409	1,555	1,570	1,448	1,336	1,212	1,092	975	802	622	450
SUM (kAF)	**118.4**	**159.3**	**178.4**	**179.6**	**175.1**	**159.9**	**139.0**	**119.1**	**99.6**	**81.4**	**65.4**	**92.7**	**96.4**	**91.8**	**88.0**	**82.0**	**71.3**	**59.7**	**49.4**	**39.8**	**31.3**	**23.8**

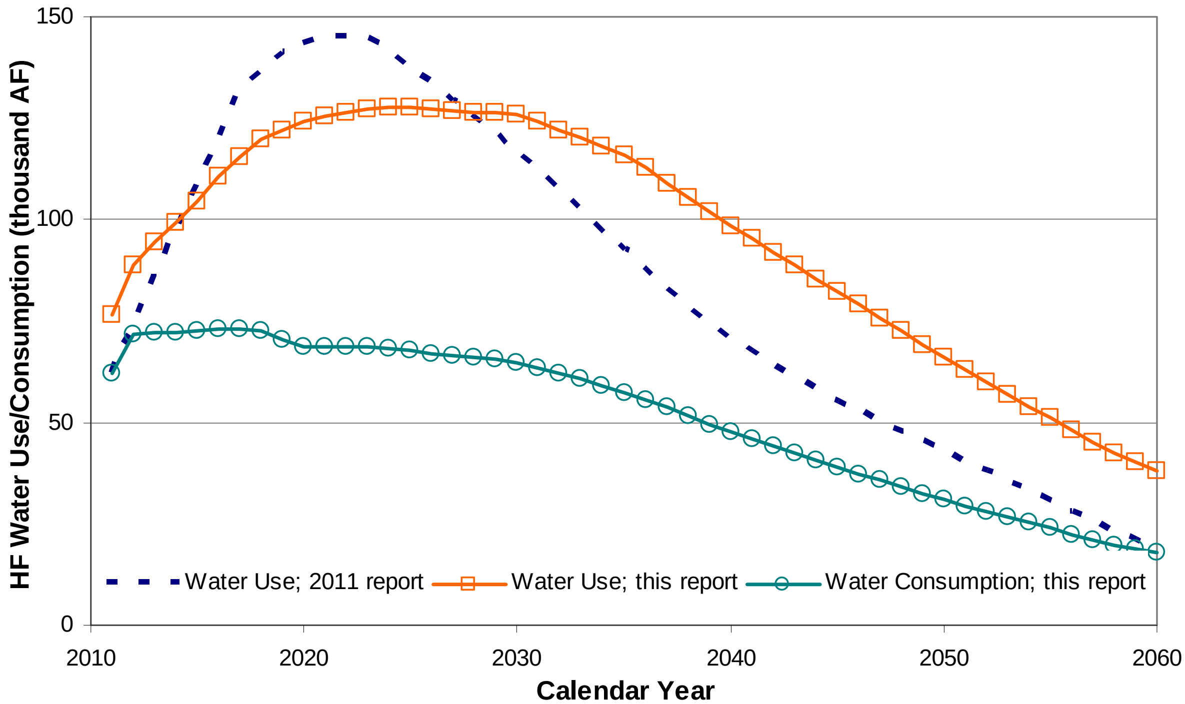
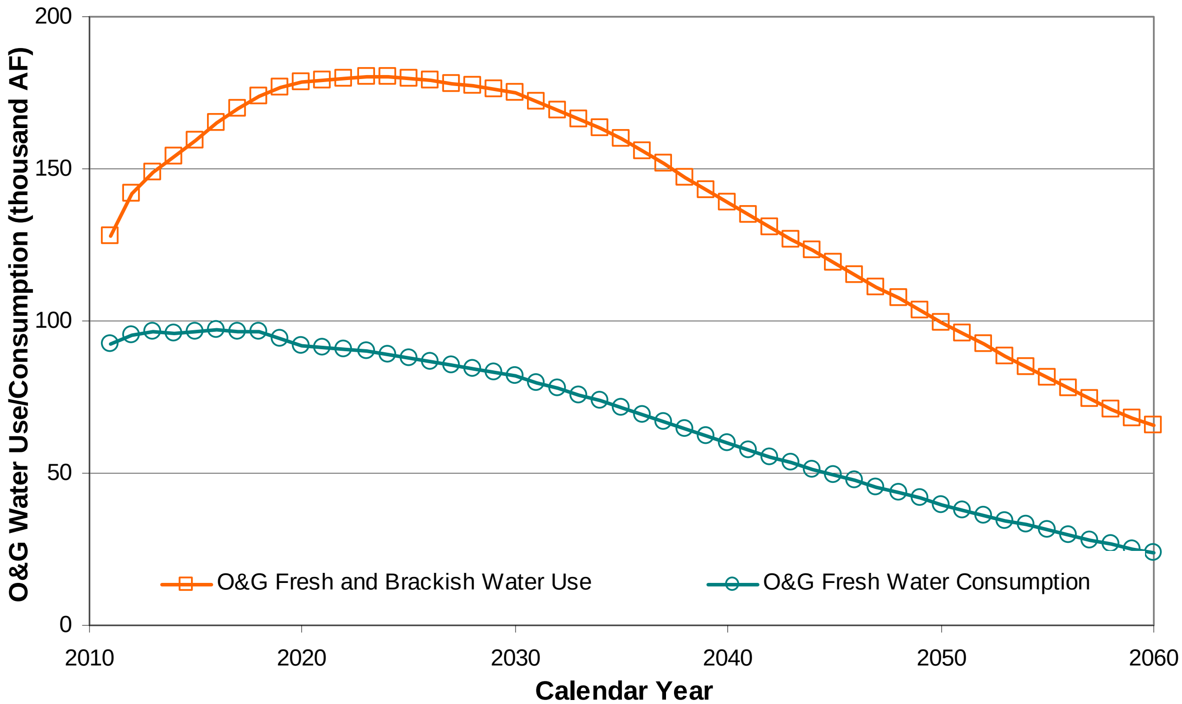


Figure 48. State-level projections to 2060 of HF water use and fresh-water consumption and comparison to earlier water projections.



O&G WaterUse&Consumption_2.xls

Figure 49. State-level projections to 2060 of oil and gas industry water use and fresh-water consumption.

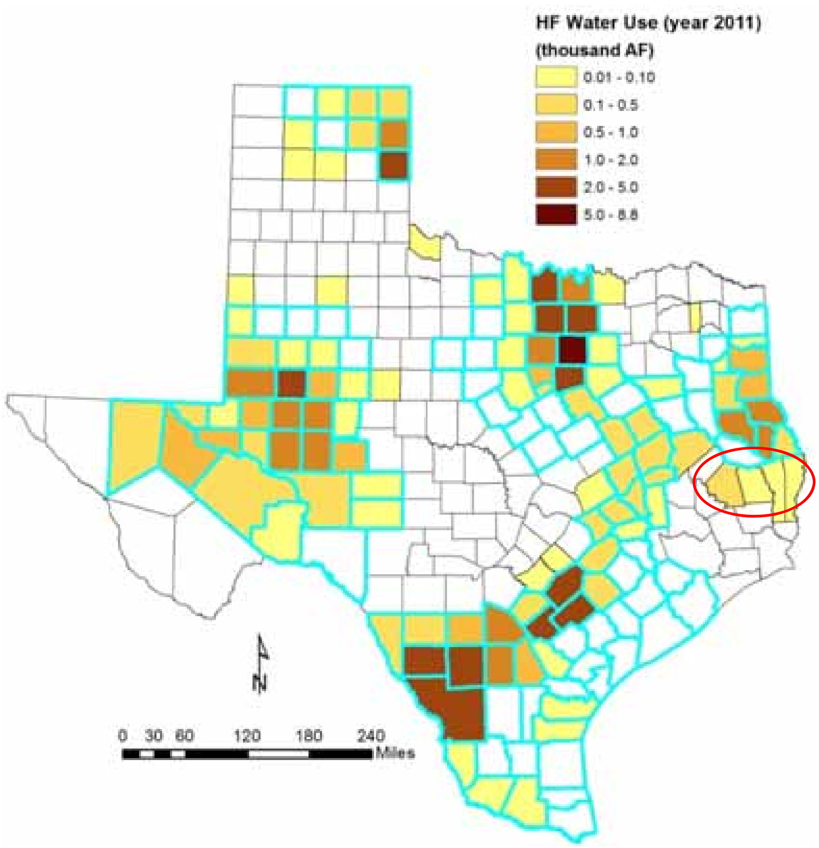
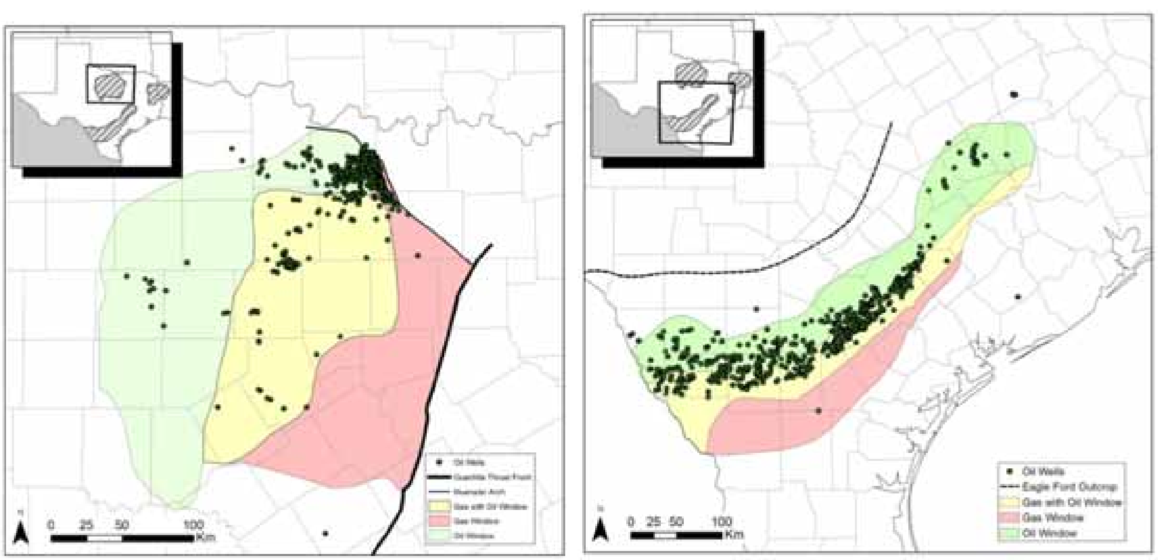
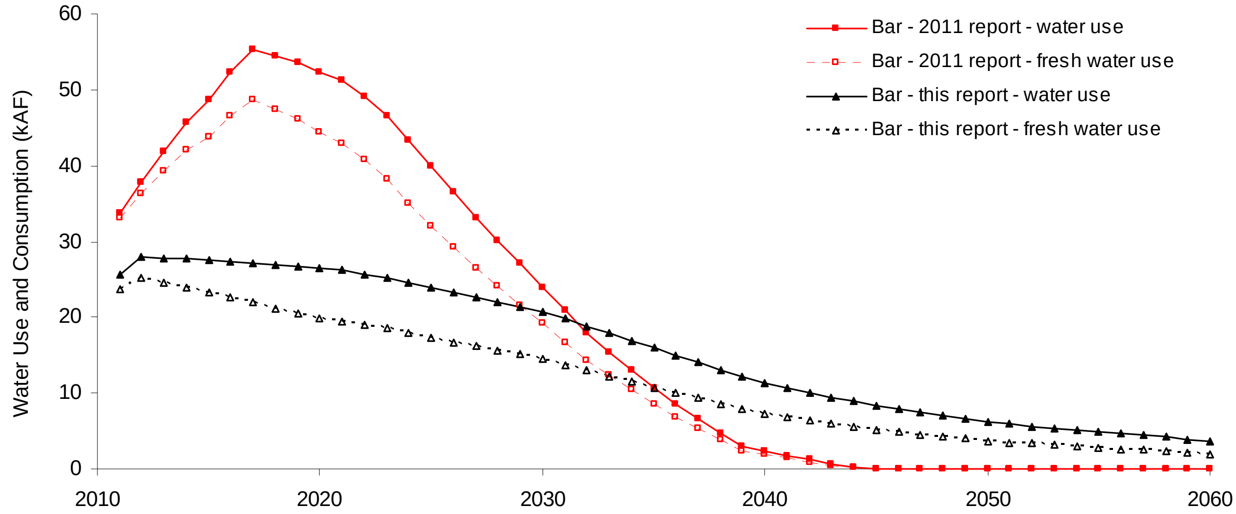


Figure 50. Counties with non-zero projected water use. Same coverage as in the 2011 report (thick blue lines) with the addition of Polk, Tyler, Jasper, and Newton counties in East Texas (red circle).

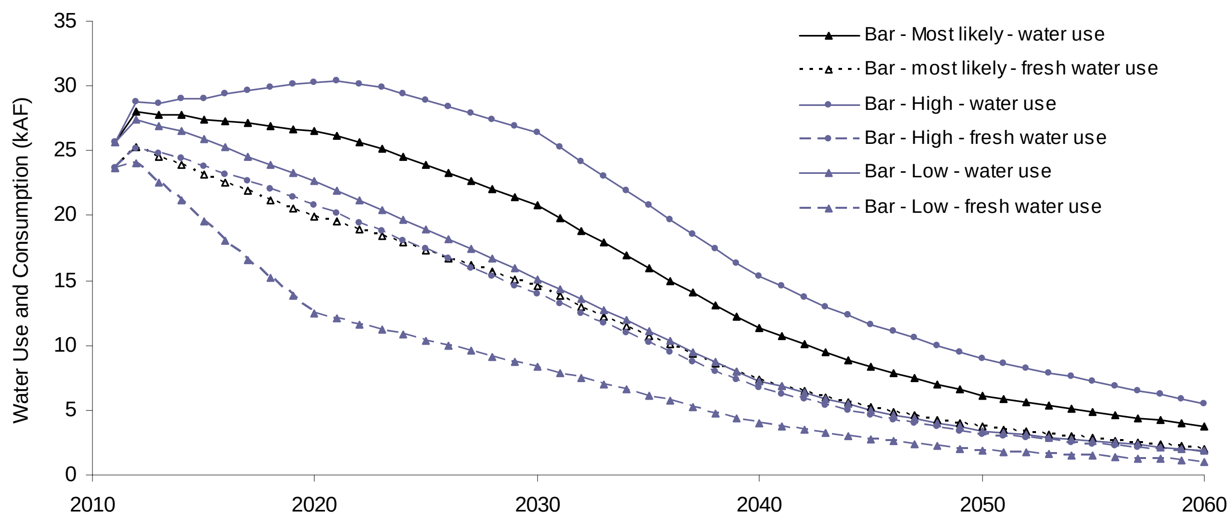


Source: Montgomery et al. (2005)　　Source: McMahon and Vaden (2011)

Figure 51. Spatial location of the oil and gas windows in the (a) Barnett Shale and (b) Eagle Ford Shale.



(a)



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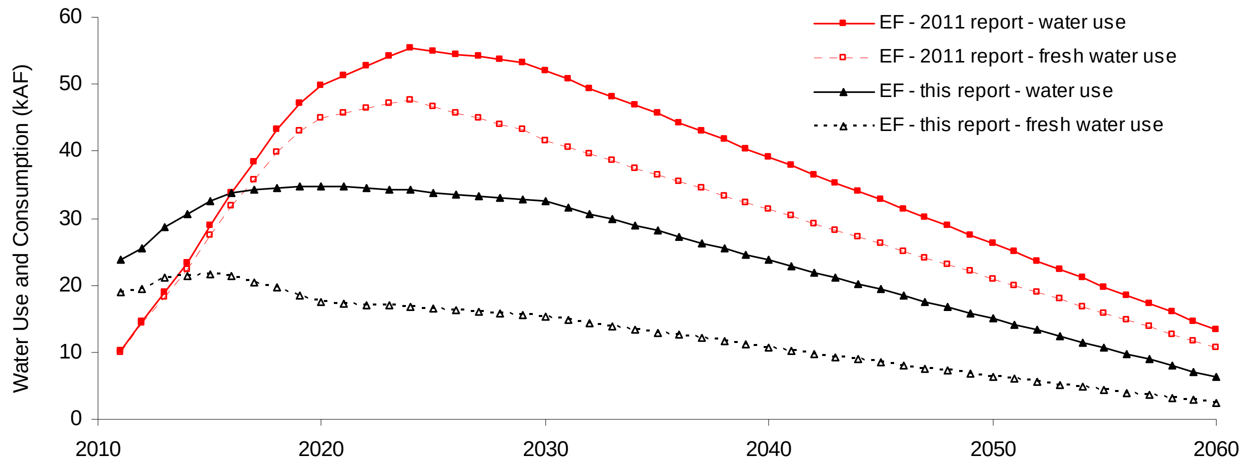
(b)

Figure 52. Barnett Shale water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.



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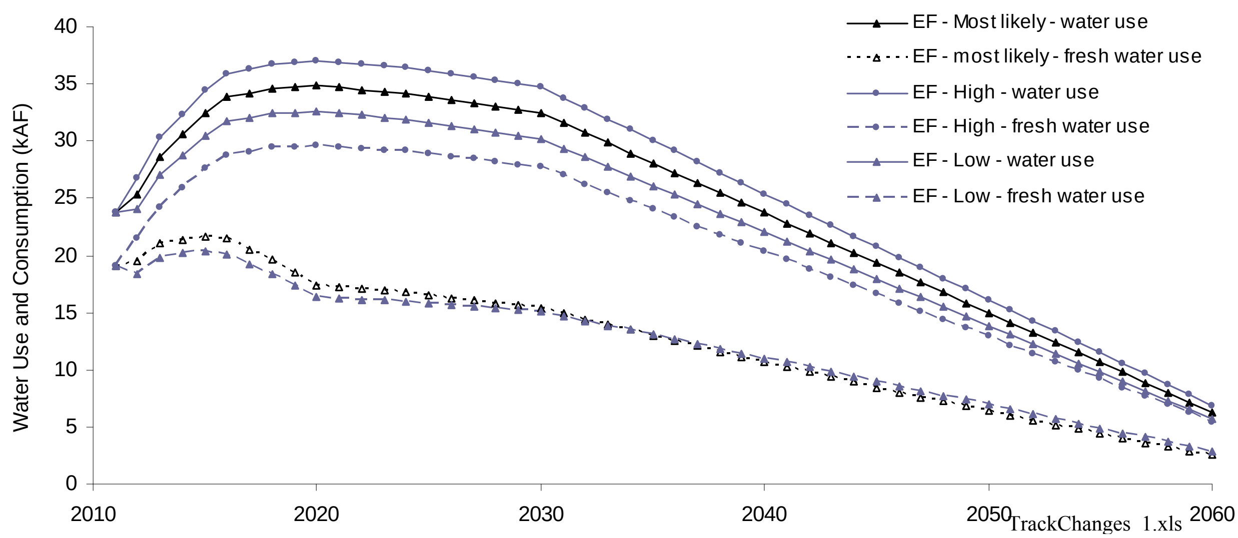
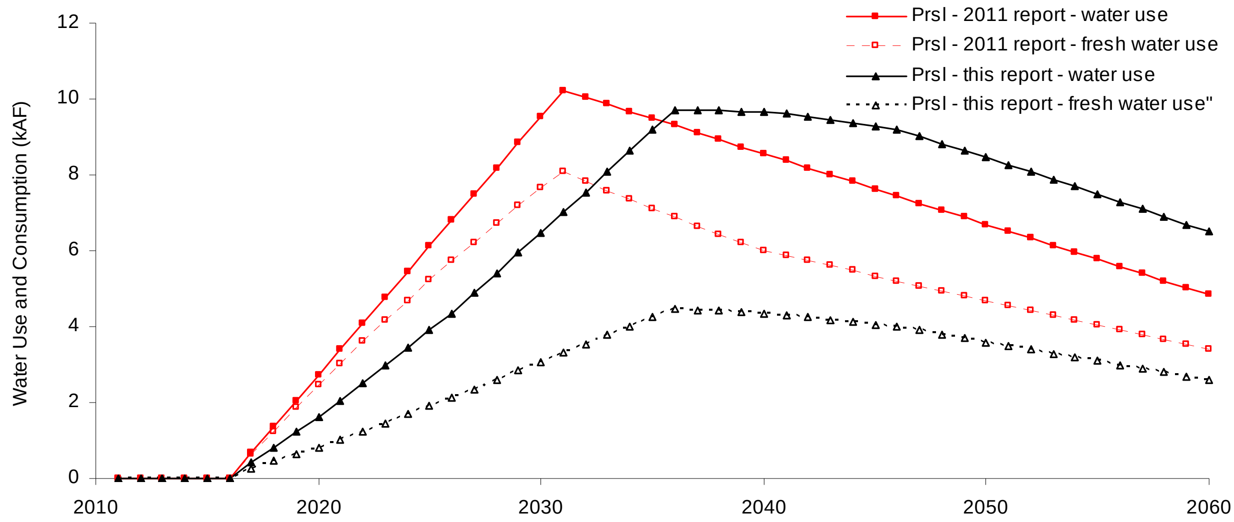


(b)

Figure 53. Eagle Ford Shale water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.



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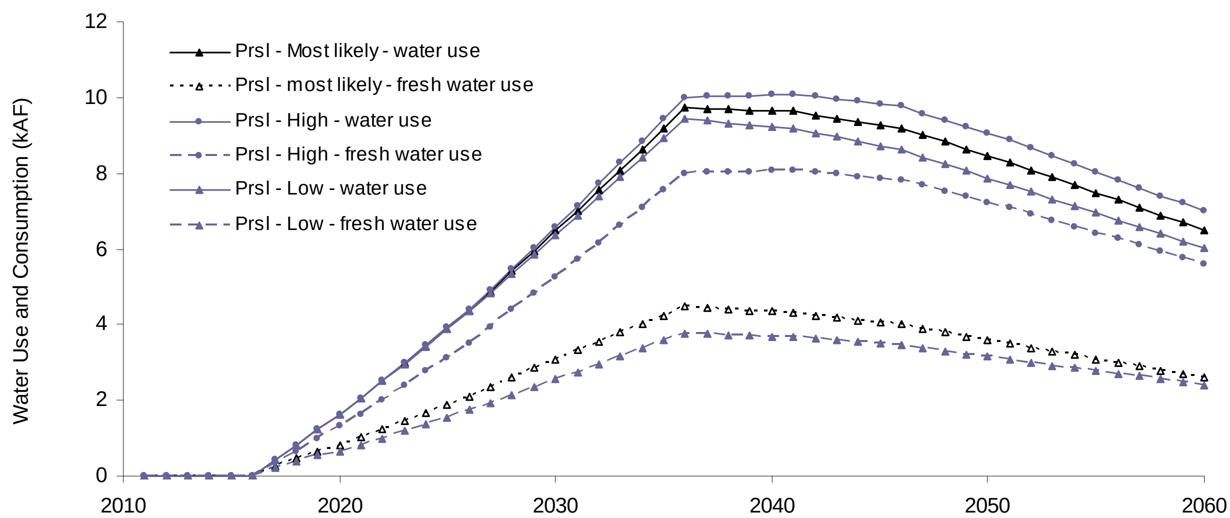

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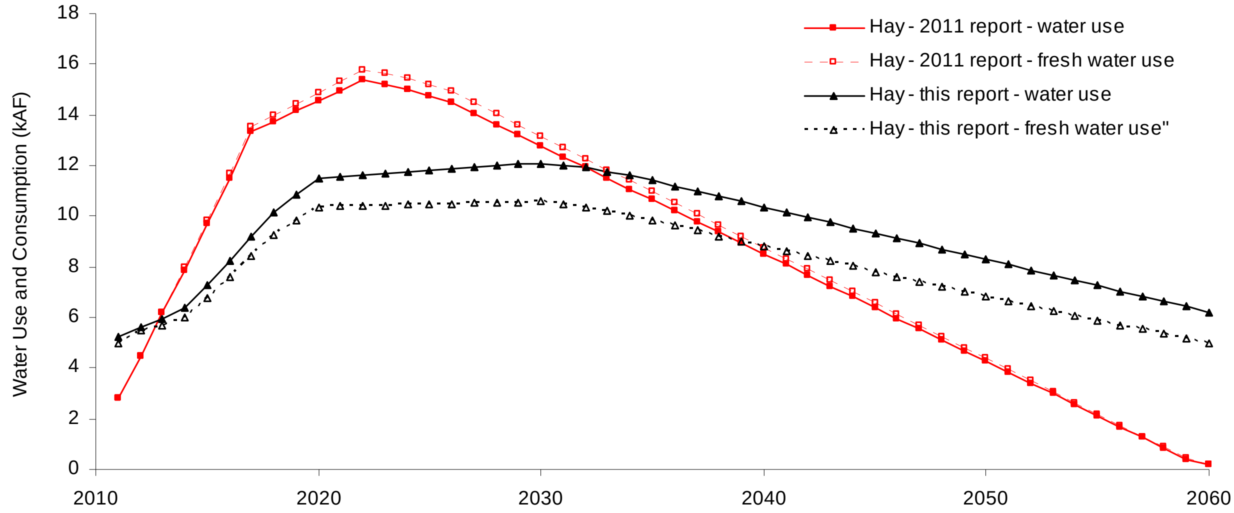
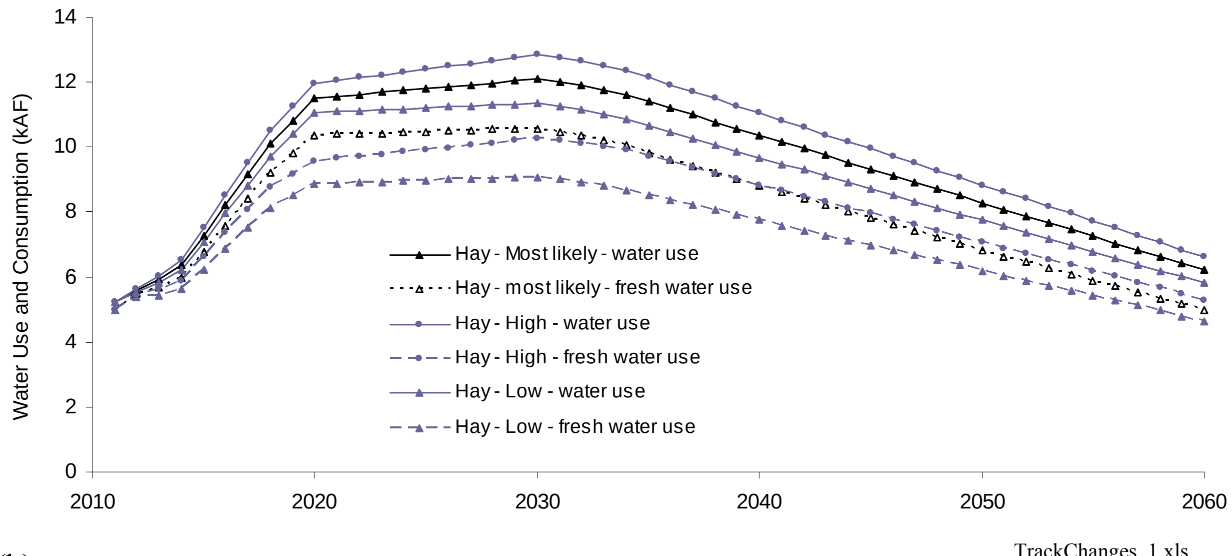
(b)

Figure 54. Pearsall Shale water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.

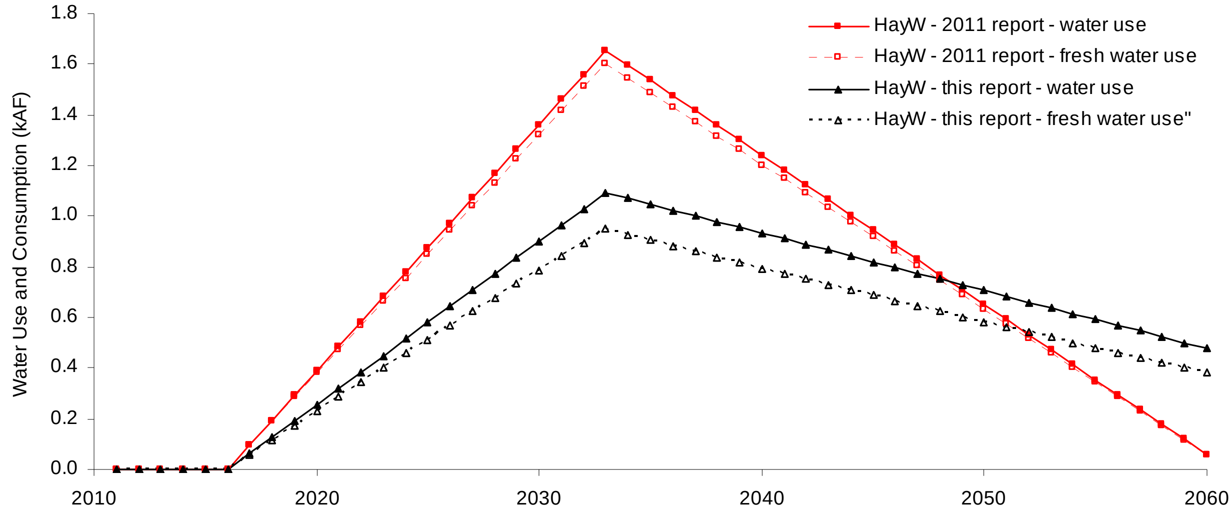


(a)

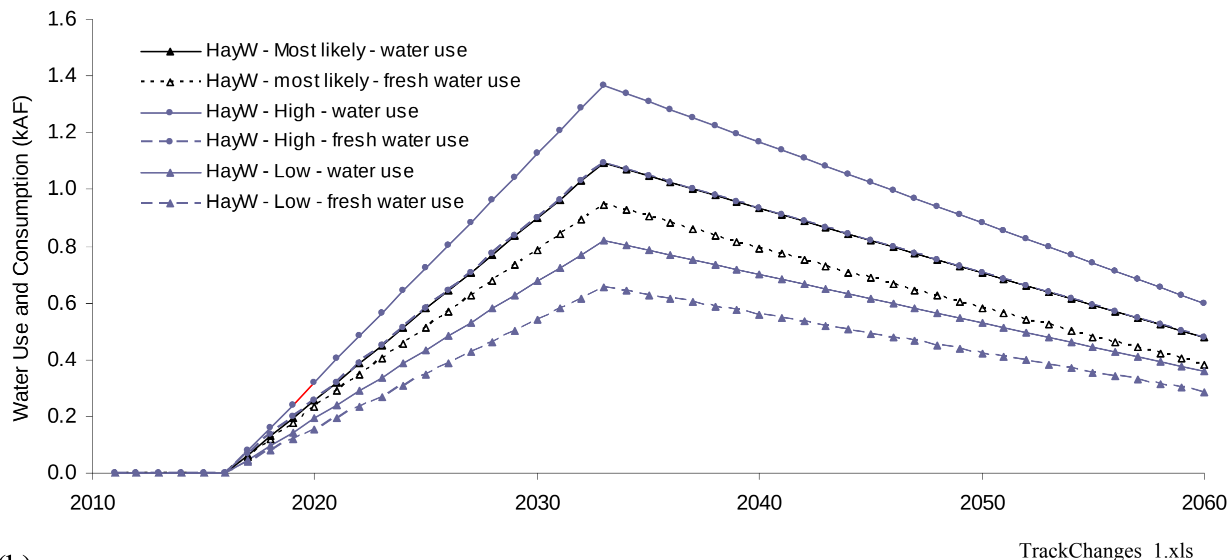


(b)

Figure 55. Haynesville and Bossier Shales water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.

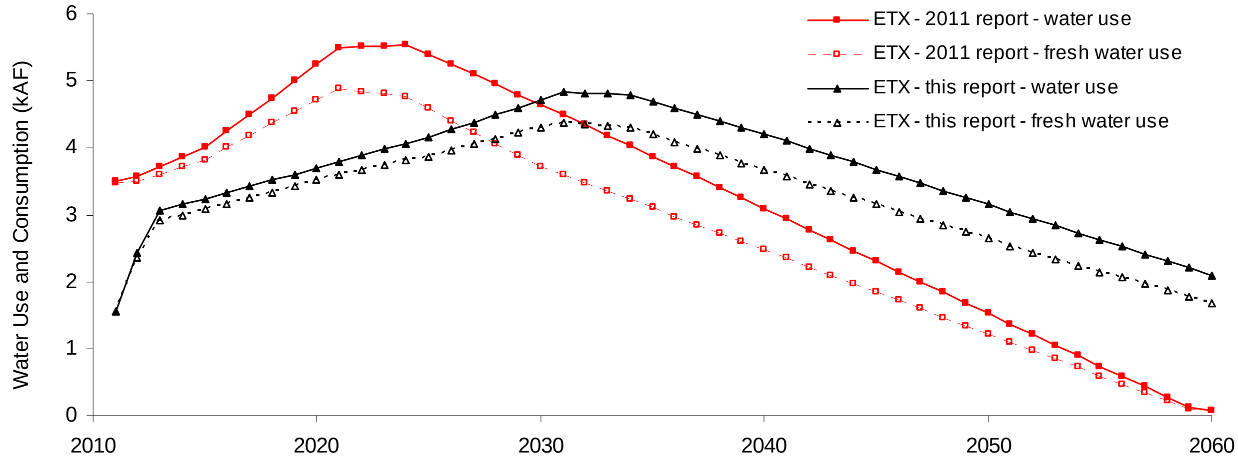


(a)



(b)

Figure 56. Haynesville-West Shale water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.



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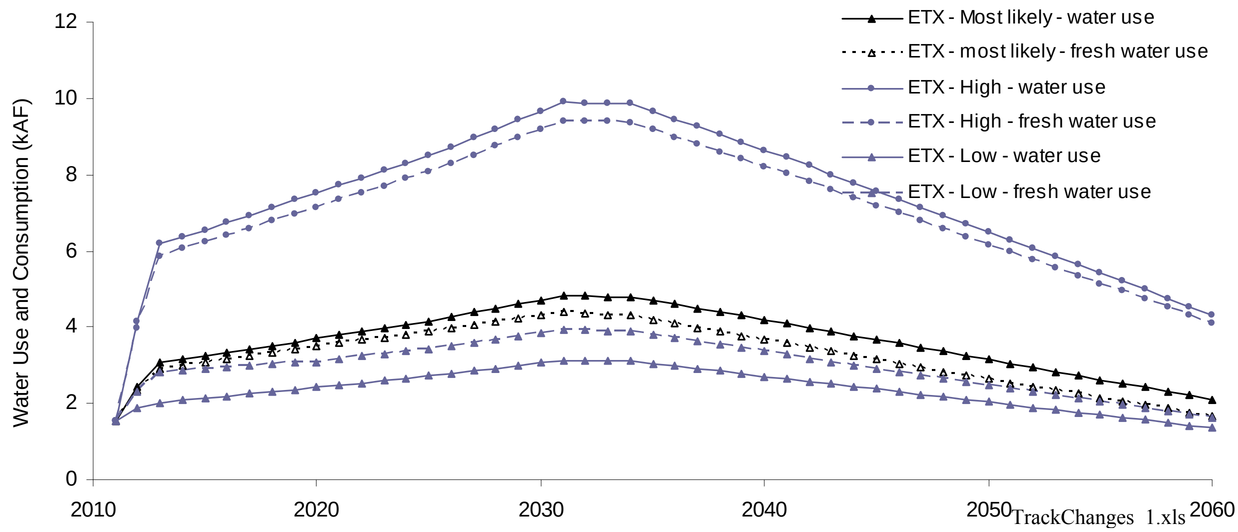
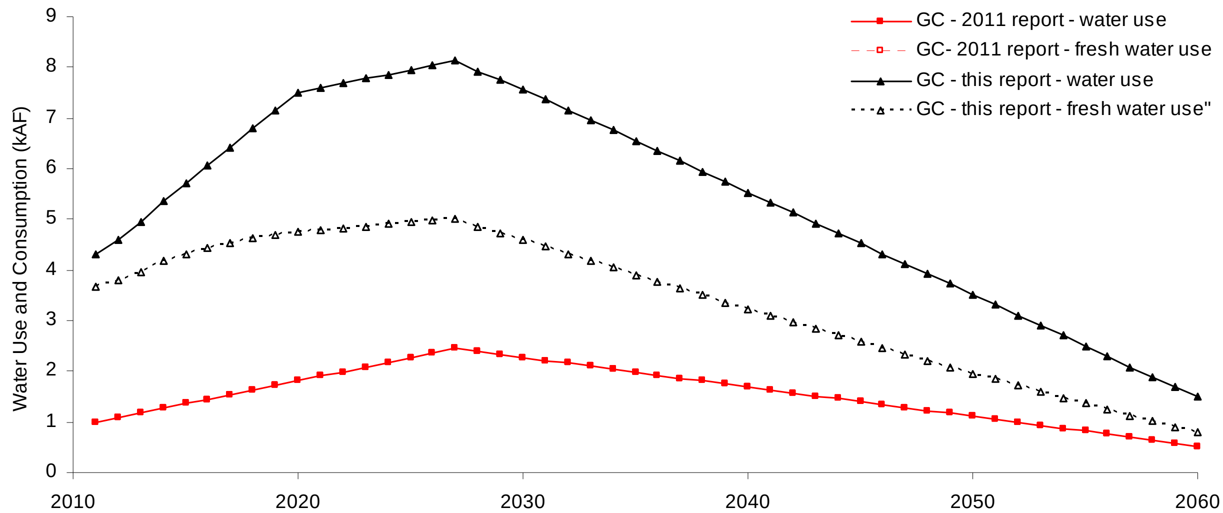
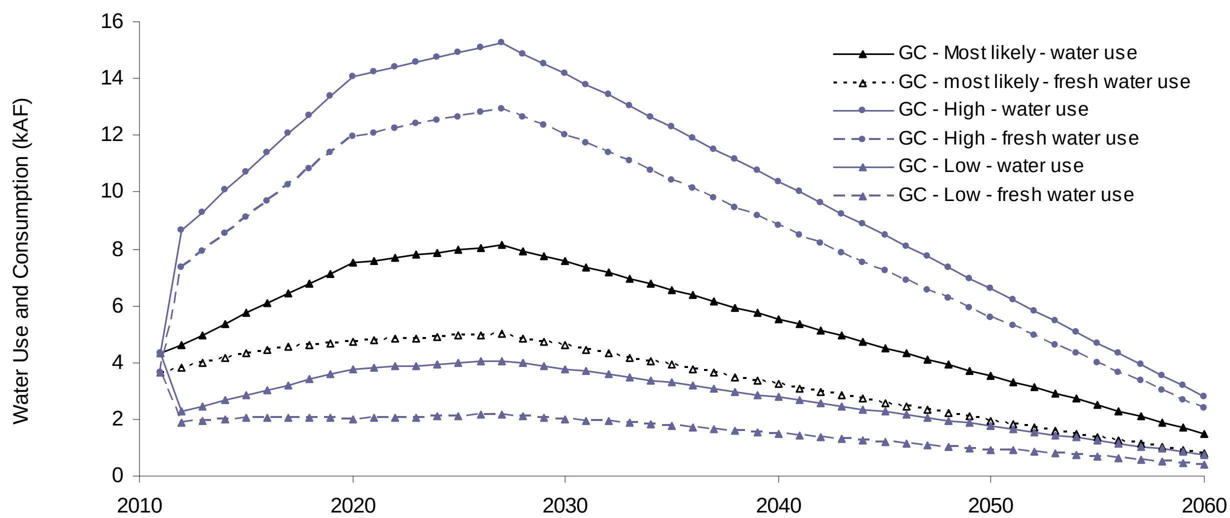


(b)

Figure 57. East Texas (not including Haynesville and Bossier Shales) water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.



(a)



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(b)

Figure 58. Gulf Coast (not including shales) water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.

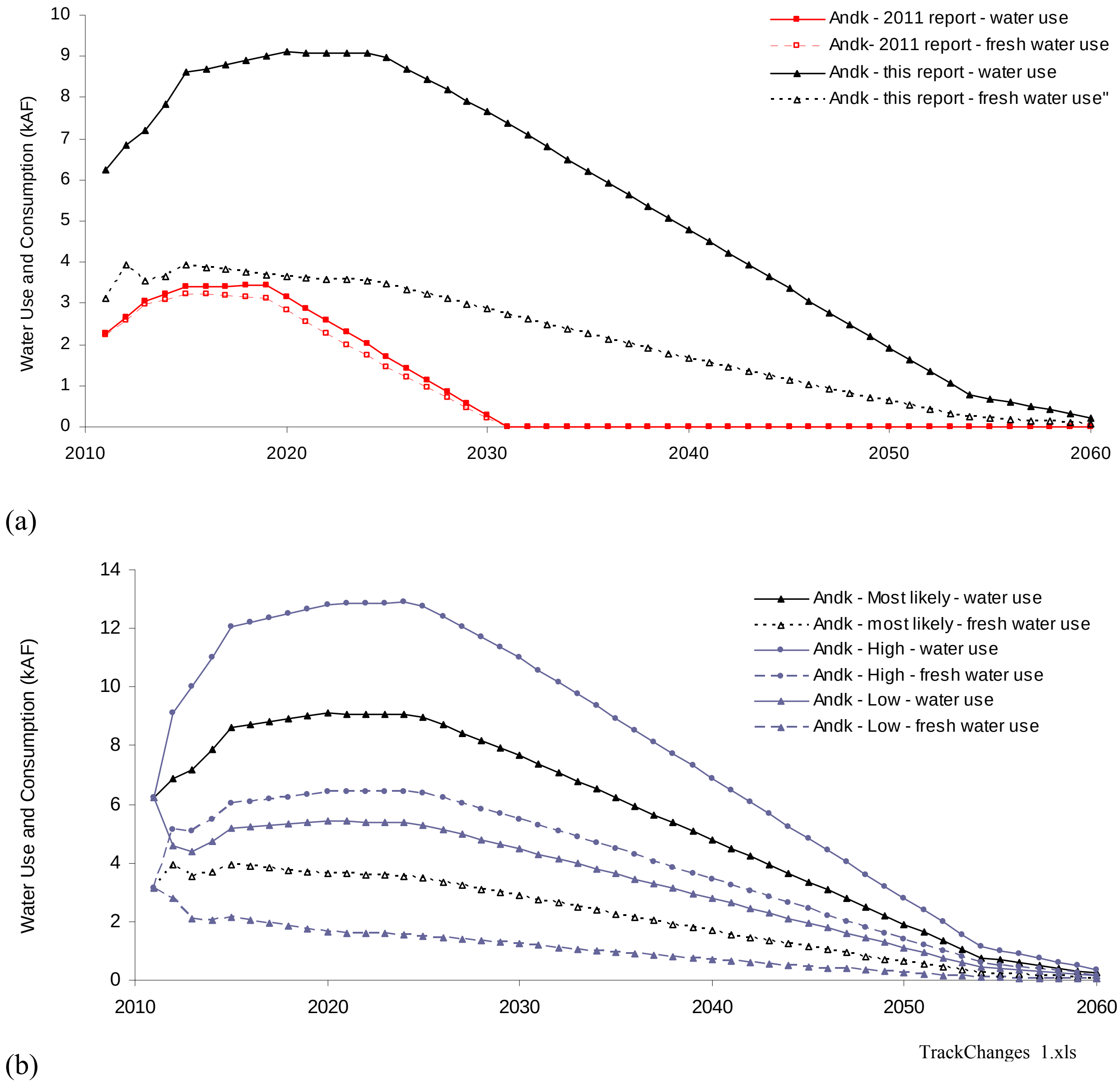
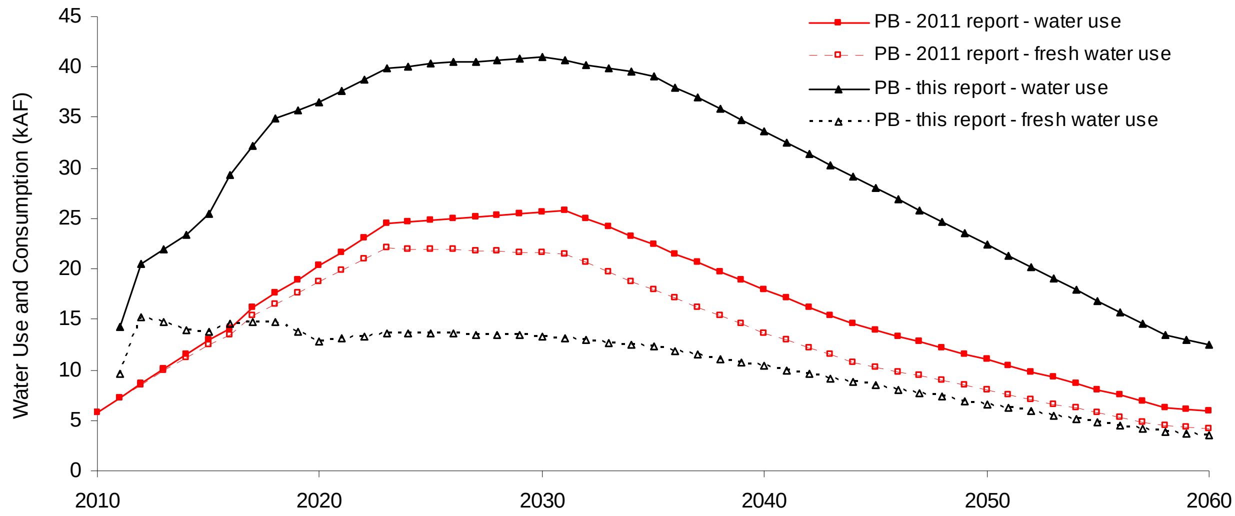


Figure 59. Anadarko Basin water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.



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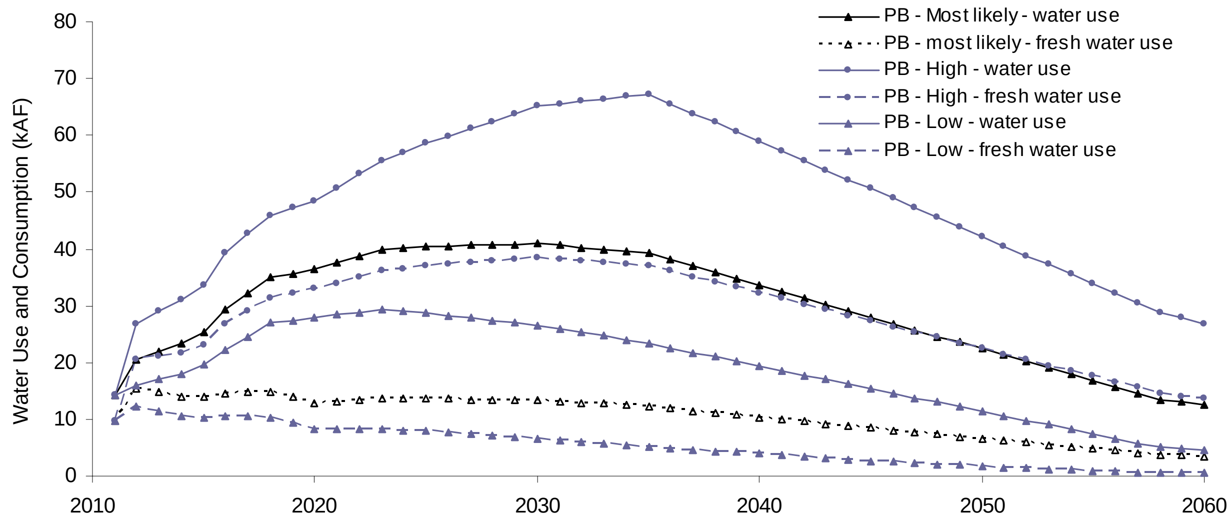

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(b)

Figure 60. Permian Basin water use and consumption projections: (a) comparison with earlier projections; (b) water use and consumption projections under the three scenarios.

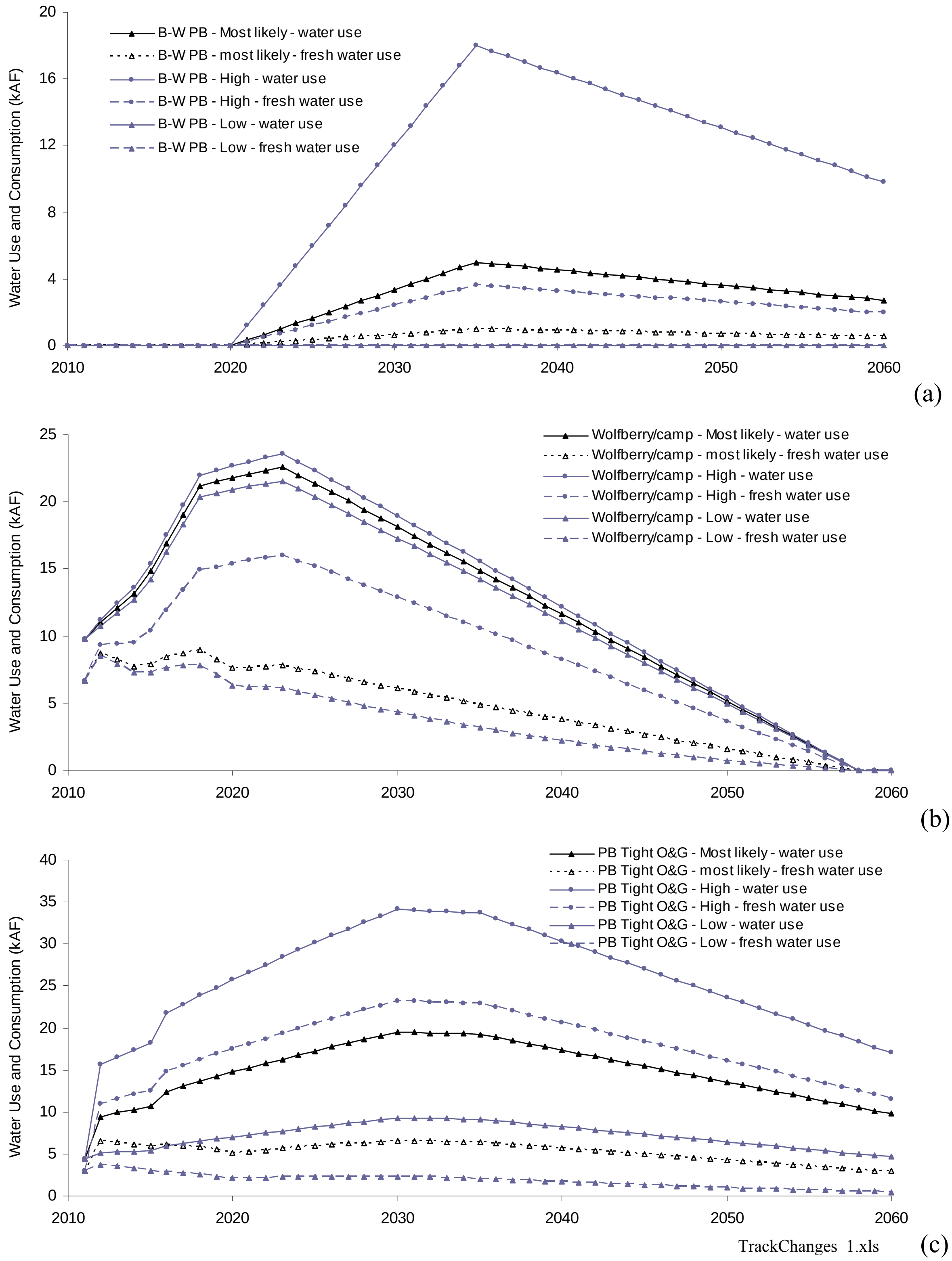
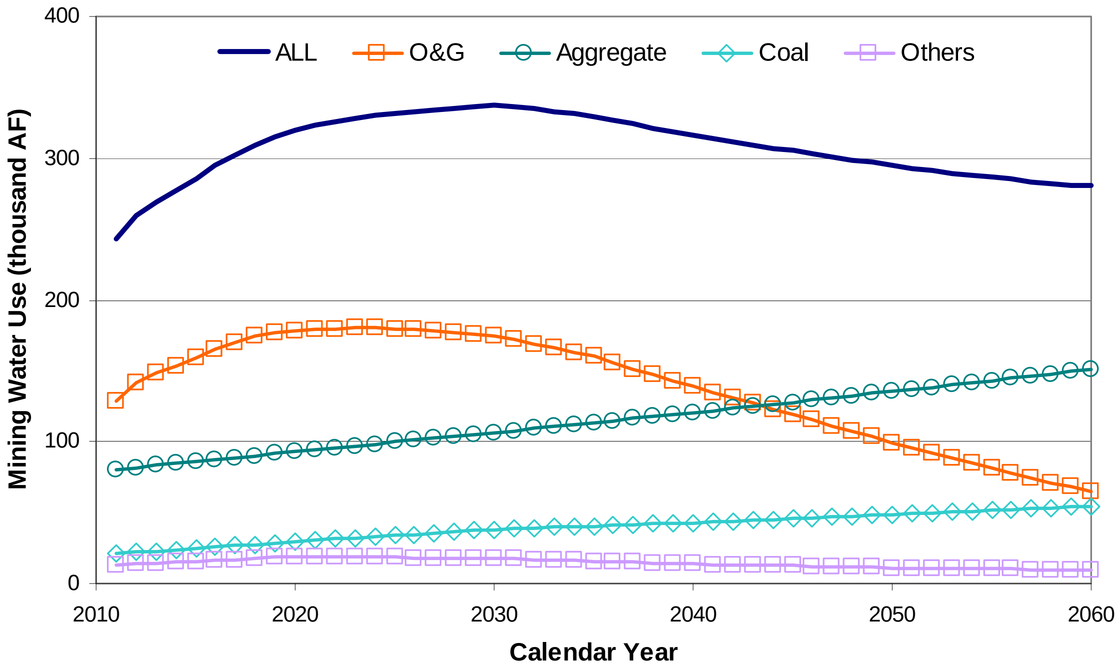


Figure 61. Permian Basin water use and consumption projections under the three scenarios: (a) Barnett and Woodford Shales; (b) Wolfcamp Shale and Wolfberry play; and (c) other Permian Basin formations.

V. Conclusions

This update to the 2011 report (whose conclusions were partly summarized in Nicot and Scanlon, 2012) does not fundamentally change the water use projections put forward originally. Both documents outline a water use that is likely to stay in the vicinity of 100±50 kAF/yr for many years. The new projections lower and broaden the expected peak water use and displace the center of gravity of HF water use toward West Texas, an area of the state that has less fresh water. This mechanically translates into a higher brackish water use which when allied with improvement in reuse technologies results in a much lower fresh water consumption than was projected in the 2011 report. The eventual solution in West Texas, after the initial step of using slightly brackish groundwater, is to use more saline brackish water or the abundant produced water from conventional wells to avoid competition with other users who will also rely more and more on brackish water as their water needs increase. In addition to this expected recycling from other uses, the industry itself is making rapidly maturing technological advances that will improve reuse. Fortunately flow back is abundant in most places where fresh water is not (such as in West Texas). However, as in all predictive work, unexpected events can generate large deviations from the projections (as the shale gas revolution did for domestic oil production). The simple discovery of an additional major play (deeper play?) beyond those described in this document could change the state-level water projections. They, however, are unlikely to deviate much in order of magnitude from those outlined here.

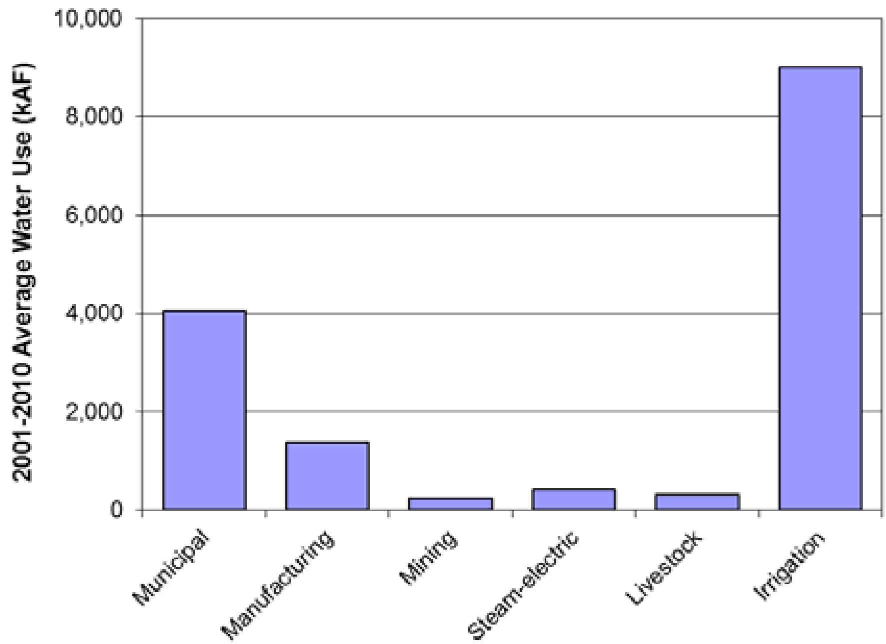
It follows that oil and gas water use projections remain a reasonable fraction of mining water use projections, no more than 54% (Figure 62) and a smaller fraction still of the total amount on water use in Texas every year: <0.1 million AF (81.5 kAF in 2011) compared to 15+ million AF (Figure 63).



MiningWaterUse2010-2060_4_TWDB_just.xls

Note: modified from the 2011 report (Nicot et al., 2011, Fig. 135)

Figure 62. Summary of projected water use by mining industry in Texas (2012-2060).



BarPlots_WaterUse_6.xls

Source: TWDB historical water use surveys,
http://www.twdb.state.tx.us/waterplanning/waterusesurvey/estimates/
Note: value displayed for mining water use is the 230 kAF from Nicot et al. (2011) rather than the projected 296 kAF listed in TWDB (2012, p.137) or the 2001-2010 average of 184.4 kAF computed with limited information.

Figure 63. Average state level water use (all categories) in 2001-2010.

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Appendix 1: Revision to 2011 Report

Although the material below is now obsolete (Table 17), we thought it was important to correct Table 52 of the 2011 report ("Projected water use in the Barnett Shale (Fort Worth Basin)"). Although correct values were used in tables of higher order (state level or cumulative across water uses) in the 2011 report, its table 52 was not updated between the draft version and the final version.

Table 17. Update to Table 52 of 2011 report (now obsolete and superseded by this report)

County	2010*	2020	2030	2040	2050	2060
	AF					
Archer	0	1,618	1,292	369	0	0
Bosque	913	2,547	1,065	0	0	0
Clay	~~634~~ 951	~~3,731~~ 5,596	~~1,663~~ 2,495	0	0	0
Comanche	429	2,524	1,125	0	0	0
Cooke	101	282	118	0	0	0
Coryell	0	1,793	1,140	263	0	0
Dallas	620	769	271	0	0	0
Denton	1,674	587	0	0	0	0
Eastland	0	1,127	1,157	386	0	0
Ellis	325	235	63	0	0	0
Erath	2,017	2,500	882	0	0	0
Hamilton	190	1,118	498	0	0	0
Hill	1,008	1,249	441	0	0	0
Hood	1,720	990	215	0	0	0
Jack	~~1,835~~ 2,386	~~1,706~~ 2,218	~~535~~ 696	0	0	0
Johnson	3,308	1,537	241	0	0	0
McLennan	0	1,380	680	62	0	0
Montague	~~539~~ 809	~~3,174~~ 4.760	~~1,415~~ 2,122	0	0	0
Palo Pinto	446	2,627	1,171	0	0	0
Parker	4,003	1,787	153	0	0	0
Shackelford	0	1,121	1,151	384	0	0
Somervell	771	443	96	0	0	0
Stephens	0	1,854	1,178	272	0	0
Tarrant	3,147	1,104	0	0	0	0
Wise	~~4,220~~ 4.642	~~1,961~~ 2,157	~~308~~ 338	0	0	0
Young	0	563	578	193	0	0
Total (Th. AF)	**~~27.9~~ 29.5**	**~~40.3~~ 44.5**	**~~17.4~~ 19.2**	**1.9**	**0.0**	**0.0**

Note: double strikethrough on the incorrect values replaced by the correct but obsolete values.

Variability of Distributions of Well-Scale Estimated Ultimate Recovery for Continuous (Unconventional) Oil and Gas Resources in the United States

By U.S. Geological Survey Oil and Gas Assessment Team

Open-File Report 2012–1118

U.S. Department of the Interior
U.S. Geological Survey

U.S. Department of the Interior
KEN SALAZAR, Secretary

U.S. Geological Survey
Marcia K. McNutt, Director

U.S. Geological Survey, Reston, Virginia: 2012

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Variability of Distributions of Well-Scale Estimated Ultimate Recovery for Continuous (Unconventional) Oil and Gas Resources in the United States

By U.S. Geological Survey Oil and Gas Assessment Team

Abstract

Since 2000, the U.S. Geological Survey has completed assessments of continuous (unconventional) resources in the United States based on geologic studies and analysis of well-production data. This publication uses those 132 continuous oil and gas assessments to show the variability of well productivity within and among the 132 areas. The production from the most productive wells in an area commonly is more than 100 times larger than that from the poorest productive wells. The 132 assessment units were classified into four categories: shale gas, coalbed gas, tight gas, and continuous oil. For each category, the mean well productivity in the most productive assessment units is considerably greater than that of the least productive assessment units.

Introduction

The U.S. Geological Survey (USGS) conducts quantitative assessments of potential oil and gas resources of the onshore United States and State waters. Since 2000, 132 assessments have been performed for continuous (unconventional) oil and gas resources, based on geologic studies and analysis of well-production data. Assessment methods are documented in Crovelli (2000, 2003), Klett and Charpentier (2003), Klett and Schmoker (2003), and Schmoker (2003). Each assessment unit (AU) was divided into cells, with each cell representing a well-drainage area. The estimates of resource potential were derived from estimates of the potential number of undrilled productive cells and of the productive capacities of those cells.

Estimated ultimate recovery (EUR) distributions were estimated for each AU, based on decline-curve analysis from monthly production data (IHS Energy, 2011) of hundreds to thousands of wells per AU. The EUR distribution used for each assessment calculation was specifically that for undrilled cells. Commonly, this EUR distribution for undrilled cells is closely similar to the distribution for drilled cells. In general, wells drilled early in the development of an AU, before drilling and completion techniques are optimized, have relatively low EURs. This can cause the estimated EURs for undrilled cells to be higher than those for drilled wells. Conversely, if the geologically most favorable parts of the AU have already been drilled, the EURs for undrilled cells may be lower than those of drilled wells.

The 132 AUs were classified into four categories: shale gas, coalbed gas, tight gas, and continuous oil. This categorization facilitated use of these data as analogs for hypothetical AUs. Sources for reports of these assessments are listed in appendix 1.

Estimated Ultimate Recovery Distributions

Shifted truncated lognormal distributions were fit using the minimum, median, and maximum input values of estimated ultimate recovery (EUR). The upper end of the distribution was truncated at the 0.1 percent (1 in 1000) fractile.

$$\mu = \ln(EUR_{med} - EUR_{min})$$

$$\sigma = \frac{\ln((EUR_{max} - EUR_{min})/(EUR_{med} - EUR_{min}))}{3.09}$$

$$E(x) = exp\left(\mu + (\sigma^2/2)\right) * \frac{normsdist((\ln(EUR_{max}) - \mu - \sigma^2)/\sigma)}{normsdist((\ln(EUR_{max}) - \mu)/\sigma)}$$

$$E(x^2) = exp(2\mu + 2\sigma^2) * \frac{normsdist((\ln(EUR_{max}) - \mu - 2\sigma^2)/\sigma)}{normsdist((\ln(EUR_{max}) - \mu)/\sigma)}$$

$$EUR_{mean} = EUR_{min} + E(x)$$

$$EUR_{sd} = \sqrt{E(x^2) - E(x)^2}$$

where:

EUR_{min} = minimum EUR

EUR_{med} = median EUR

EUR_{max} = maximum EUR

EUR_{mean} = mean EUR

EUR_{sd} = standard deviation of EUR

normsdist = normal distribution function

The input values, as well as the calculated mean for each distribution, are given in tables 1 to 4.

Table 1. Input data for estimated ultimate recovery distributions for United States shale-gas assessment units, values in billions of cubic feet of natural gas. [AU, assessment unit; and EUR, estimated ultimate recovery]

AU number	AU name	Province	Year assessed	Minimum EUR	Median EUR	Maximum EUR	Mean EUR
50490161	Haynesville Sabine Platform Shale Gas	Gulf Coast Mesozoic	2010	0.02	2	20	2.617
50490163	Mid-Bossier Sabine Platform Shale Gas	Gulf Coast Mesozoic	2010	0.02	1	10	1.308
50580161	Woodford Shale Gas	Anadarko Basin	2010	0.02	0.8	15	1.233
50670468	Interior Marcellus	Appalachian Basin	2011	0.02	0.8	12	1.158
50490167	Eagle Ford Shale Gas	Gulf Coast Mesozoic	2010	0.02	0.8	10	1.104
50620362	Fayetteville Shale Gas - High Gamma-Ray Depocenter	Arkoma Basin	2010	0.02	0.8	10	1.104
50450161	Greater Newark East Frac-Barrier Continuous Barnett Shale Gas	Bend Arch-Fort Worth Basin	2003	0.02	0.7	10	1.000
50440161	Delaware/Pecos Basins Woodford Continuous Shale Gas	Permian Basin	2007	0.02	0.6	8	0.842
50440162	Delaware/Pecos Basins Barnett Continuous Shale Gas	Permian Basin	2007	0.02	0.6	8	0.842
50580261	Thirteen Finger Limestone-Atoka Shale Gas	Anadarko Basin	2010	0.02	0.5	10	0.785
50620261	Woodford Shale Gas	Arkoma Basin	2010	0.02	0.5	10	0.785
50210364	Gothic, Chimney Rock, Hovenweep Shale Gas	Paradox Basin	2011	0.02	0.4	10	0.672
50630561	Devonian Antrim Continuous Gas	Michigan Basin	2004	0.02	0.4	4	0.523
50620363	Fayetteville Shale Gas - Western Arkansas Basin Margin	Arkoma Basin	2010	0.02	0.3	6	0.470
50210362	Cane Creek Shale Gas	Paradox Basin	2011	0.02	0.3	5	0.446
50440163	Midland Basin Woodford/Barnett Continuous Gas	Permian Basin	2007	0.02	0.3	5	0.446
50490165	Maverick Basin Pearsall Shale Gas	Gulf Coast Mesozoic	2010	0.02	0.25	5	0.391
50450162	Extended Continuous Barnett Shale Gas	Bend Arch-Fort Worth Basin	2003	0.02	0.2	5	0.334
50390761	Niobrara Chalk	Denver Basin	2001	0.025	0.2	2	0.261
50620262	Chattanooga Shale Gas	Arkoma Basin	2010	0.02	0.1	6	0.223
50670467	Foldbelt Marcellus	Appalachian Basin	2011	0.02	0.1	5	0.208
50620364	Caney Shale Gas	Arkoma Basin	2010	0.02	0.08	5	0.179
50670469	Western Margin Marcellus	Appalachian Basin	2011	0.02	0.05	5	0.129
50640361	Devonian to Mississippian New Albany Continuous Gas	Illinois Basin	2007	0.01	0.08	1	0.110
50670462	Northwestern Ohio Shale	Appalachian Basin	2002	0.01	0.04	0.5	0.055
50670463	Devonian Siltstone and Shale	Appalachian Basin	2002	0.01	0.03	0.5	0.044

Table 2. Input data for estimated ultimate recovery distributions for United States coalbed-gas assessment units, values in billions of cubic feet of natural gas. [AU, assessment unit; and EUR, estimated ultimate recovery]

AU number	AU name	Province	Year assessed	Minimum EUR	Median EUR	Maximum EUR	Mean EUR
50220181	Fruitland Fairway Coalbed Gas	San Juan Basin	2002	0.02	8	40	9.125
50200181	Northern Coal Fairway/Drunkards Wash	Uinta-Piceance	2000	0.05	0.8	12	1.156
50220182	Basin Fruitland Coalbed Gas	San Juan Basin	2002	0.02	0.6	20	1.110
50200182	Central Coal Fairway/Buzzards Bench	Uinta-Piceance	2000	0.05	0.4	10	0.666
50010181	Nanushuk Formation Coalbed Gas	Northern Alaska	2006	0.02	0.25	12	0.524
50410182	Vermejo Coalbed Gas	Raton Basin-Sierra Grande Uplift	2004	0.02	0.25	9.5	0.481
50200281	Uinta Basin Blackhawk Coalbed Gas	Uinta-Piceance	2000	0.05	0.25	10	0.480
50360281	Frontier-Adaville-Evanston Coalbed Gas	Wyoming Thrust Belt	2003	0.02	0.4	2	0.456
50410181	Raton Coalbed Gas	Raton Basin-Sierra Grande Uplift	2004	0.02	0.25	8	0.453
50650281	Warrior Basin	Warrior Basin	2002	0.01	0.25	5	0.392
50620481	Arkoma Coalbed Gas	Arkoma Basin	2010	0.02	0.3	3	0.392
50330182	Upper Fort Union Formation	Powder River Basin	2000	0.02	0.23	4	0.345
50200183	Southern Coal Fairway	Uinta-Piceance	2000	0.05	0.2	5	0.328
50210581	Kaiparowits Plateau	Paradox Basin	2011	0.02	0.2	4	0.312
50010183	Sagavanirktok Formation Coalbed Gas	Northern Alaska	2006	0.02	0.18	5	0.310
50330181	Wasatch Formation	Powder River Basin	2000	0.02	0.18	3	0.267
50370882	Fort Union Coalbed Gas	Southwestern Wyoming	2002	0.02	0.2	1.5	0.246
50670581	Pocahontas Basin	Appalachian Basin	2002	0.01	0.15	2	0.210
50350281	Mesaverde Coalbed Gas	Wind River Basin	2005	0.02	0.1	5	0.208
50030281	Cook Inlet Coalbed Gas	Southern Alaska	2011	0.02	0.16	1.5	0.206
50370881	Lance Coalbed Gas	Southwestern Wyoming	2002	0.02	0.15	1	0.180
50200282	Mesaverde Group Coalbed Gas	Uinta-Piceance	2000	0.02	0.08	5	0.179
50220381	Menefee Coalbed Gas	San Juan Basin	2002	0.02	0.08	5	0.179
50200185	Southern Coal Outcrop	Uinta-Piceance	2001	0.05	0.1	3	0.165
50670582	Eastern Dunkard Basin	Appalachian Basin	2002	0.01	0.1	2	0.156
50040381	Eocene Coalbed Gas	Western Oregon-Washington	2009	0.02	0.1	2	0.155
50010182	Prince Creek–Tuluvak Formations Coalbed Gas	Northern Alaska	2006	0.02	0.1	1.5	0.143
50340281	Mesaverde-Meeteetse Formation Coalbed Gas	Big Horn Basin	2008	0.02	0.1	1.2	0.136
50350282	Meeteetse Coalbed Gas	Wind River Basin	2005	0.02	0.08	2	0.131
50350283	Fort Union Coalbed Gas	Wind River Basin	2005	0.02	0.08	2	0.131
50370682	Fort Union Coalbed Gas	Southwestern Wyoming	2002	0.02	0.1	1	0.130
50370981	Wasatch-Green River Coalbed Gas	Southwestern Wyoming	2002	0.02	0.1	0.8	0.124
50311081	Fort Union Coalbed Gas	Williston Basin	2008	0.02	0.085	1	0.114
50330183	Lower Fort Union-Lance Formations	Powder River Basin	2000	0.02	0.085	1	0.114
50340282	Fort Union Formation Coalbed Gas	Big Horn Basin	2008	0.02	0.08	1	0.109
50370581	Mesaverde Coalbed Gas	Southwestern Wyoming	2002	0.02	0.06	2	0.106
50370681	Mesaverde Coalbed Gas	Southwestern Wyoming	2002	0.02	0.06	2	0.106
50470381	Wilcox Coalbed Gas	Western Gulf	2007	0.01	0.05	0.5	0.065
50640481	Desmoinesian-Virgilian Coalbed Gas	Illinois Basin	2007	0.01	0.03	0.25	0.037
50470281	Cretaceous Olmos Coalbed Gas	Western Gulf	2007	0.01	0.03	0.1	0.032

Table 3. Input data for estimated ultimate recovery distributions for United States tight-gas assessment units, values in billions of cubic feet of natural gas. [AU, assessment unit; and EUR, estimated ultimate recovery]

AU number	AU name	Province	Year assessed	Minimum EUR	Median EUR	Maximum EUR	Mean EUR
50370661	Mesaverde-Lance-Fort Union Continuous Gas	Southwestern Wyoming	2002	0.02	1.2	15	1.657
50370561	Almond Continuous Gas	Southwestern Wyoming	2002	0.02	0.9	20	1.460
50200261	Uinta Basin Continuous Gas	Uinta-Piceance	2000	0.02	0.5	40	1.293
50030161	Tuxedni-Naknek Continuous Gas	Southern Alaska	2011	0.02	0.6	30	1.286
50620161	Arkoma-Ouachita Foredeep Continuous	Arkoma Basin	2010	0.02	0.6	30	1.286
50350261	Frontier-Muddy Continuous Gas	Wind River Basin	2005	0.02	0.7	15	1.123
50370261	Mowry Continuous Gas	Southwestern Wyoming	2002	0.02	0.7	15	1.123
50350265	Lance-Fort Union Sandstone Gas	Wind River Basin	2005	0.02	0.6	20	1.110
50370861	Lance-Fort Union Continuous Gas	Southwestern Wyoming	2002	0.02	0.8	10	1.104
50370761	Lewis Continuous Gas	Southwestern Wyoming	2002	0.02	0.6	15	1.009
50200362	Uinta Basin Continuous Gas	Uinta-Piceance	2000	0.02	0.5	16	0.911
50200263	Piceance Basin Continuous Gas	Uinta-Piceance	2000	0.02	0.5	15	0.892
50350264	Mesaverde-Meeteetse Sandstone Gas	Wind River Basin	2005	0.02	0.5	15	0.892
50350262	Cody Sandstones Continuous Gas	Wind River Basin	2005	0.02	0.4	20	0.855
50670364	Tuscarora Basin Center	Appalachian Basin	2002	0.01	0.7	4	0.817
50220261	Lewis Continuous Gas	San Juan Basin	2002	0.02	0.5	6	0.683
50220361	Mesaverde Central-Basin Continuous Gas	San Juan Basin	2002	0.02	0.5	6	0.683
50220363	Dakota-Greenhorn Continuous Gas	San Juan Basin	2002	0.02	0.4	8	0.627
50370461	Hilliard-Baxter-Mancos Continuous Gas	Southwestern Wyoming	2002	0.02	0.4	8	0.627
50200161	Deep (6,000 feet plus) Coal and Sandstone Gas	Uinta-Piceance	2000	0.2	0.5	4	0.617
50200262	Uinta Basin Transitional Gas	Uinta-Piceance	2000	0.02	0.25	15	0.570
50340261	Muddy-Frontier Sandstone and Mowry Fractured Shale Continuous Gas	Big Horn Basin	2008	0.02	0.35	7.5	0.560
50220362	Mancos Sandstones Continuous Gas	San Juan Basin	2002	0.02	0.35	5	0.499
50370562	Rock Springs-Ericson Continuous Gas	Southwestern Wyoming	2002	0.02	0.4	3	0.491
50200361	Piceance Basin Continuous Gas	Uinta-Piceance	2000	0.02	0.25	10	0.490
50280163	Eagle Sandstone and Claggett Shale West	North-Central Montana	2000	0.01	0.25	9	0.475
50220161	Pictured Cliffs Continuous Gas	San Juan Basin	2002	0.02	0.25	7	0.434
50280162	Eagle Sandstone and Claggett Shale East	North-Central Montana	2000	0.01	0.2	7	0.375

Table 3. Input data for estimated ultimate recovery distributions for United States tight-gas assessment units, values in billions of cubic feet of natural gas. [AU, assessment unit; and EUR, estimated ultimate recovery]—Continued

AU number	AU name	Province	Year assessed	Minimum EUR	Median EUR	Maximum EUR	Mean EUR
50200363	Uinta-Piceance Transitional and Migrated Gas	Uinta-Piceance	2000	0.02	0.2	7	0.373
50200264	Piceance Basin Transitional Gas	Uinta-Piceance	2000	0.02	0.25	4	0.367
50280166	Greenhorn-Upper Belle Fourche	North-Central Montana	2000	0.01	0.2	6	0.356
50280167	Bowdoin Dome	North-Central Montana	2000	0.01	0.2	5	0.336
50340263	Cody Sandstone Continuous Gas	Big Horn Basin	2008	0.02	0.2	5	0.334
50340264	Mesaverde Sandstone Continuous Gas	Big Horn Basin	2008	0.02	0.2	5	0.334
50280165	Greenhorn-Lower Belle Fourche	North-Central Montana	2000	0.01	0.25	2.5	0.327
50050161	Columbia Basin Continuous Gas	Eastern Oregon and Washington	2006	0.02	0.2	3	0.288
50390662	Dakota Group Basin-Center Gas	Denver Basin	2001	0.02	0.2	2.5	0.275
50670461	Greater Big Sandy	Appalachian Basin	2002	0.01	0.15	2	0.210
50330461	Shallow Continuous Biogenic Gas	Powder River Basin	2002	0.01	0.08	1.5	0.122
50670361	Clinton-Medina Basin Center	Appalachian Basin	2002	0.01	0.08	1.2	0.115
50670465	Catskill Sandstones and Siltstones	Appalachian Basin	2002	0.01	0.07	1.5	0.111
50280161	Judith River Formation	North-Central Montana	2000	0.01	0.06	2	0.109
50280164	Niobrara-Carlile	North-Central Montana	2000	0.01	0.07	1	0.099
50670363	Clinton-Medina Transitional	Appalachian Basin	2002	0.01	0.06	1	0.089
50670362	Clinton-Medina Transitional Northeast	Appalachian Basin	2002	0.01	0.06	0.9	0.086
50670466	Berea Sandstone	Appalachian Basin	2002	0.01	0.03	0.5	0.044

Table 4. Input data for estimated ultimate recovery distributions for United States continuous-oil assessment units, values in millions of barrels of oil. [AU, assessment unit; and EUR, estimated ultimate recovery]

AU number	AU name	Province	Year assessed	Minimum EUR	Median EUR	Maximum EUR	Mean EUR
50310164	Eastern Expulsion Threshold	Williston Basin	2008	0.002	0.12	5	0.241
50310163	Nesson-Little Knife Structural	Williston Basin	2008	0.002	0.09	4	0.185
50210361	Cane Creek Shale Oil	Paradox Basin	2011	0.002	0.08	3	0.154
50310165	Northwest Expulsion Threshold	Williston Basin	2008	0.002	0.065	4	0.151
50310161	Elm Coulee-Billings Nose	Williston Basin	2008	0.002	0.08	2	0.135
50270561	Marias River Shale Continuous Oil	Montana Thrust Belt	2002	0.001	0.08	1.6	0.126
50370361	Niobrara Continuous Oil	Southwestern Wyoming	2002	0.001	0.08	1.6	0.126
50300361	Niobrara Continuous Oil	Hanna, Laramie, Shirley Basins	2005	0.001	0.04	1.6	0.079
50310162	Central Basin-Poplar Dome	Williston Basin	2008	0.002	0.025	2	0.064
50210363	Gothic, Chimney Rock, Hovenweep Shale Oil	Paradox Basin	2011	0.002	0.03	1.5	0.064
50580162	Woodford Shale Oil	Anadarko Basin	2010	0.003	0.03	1.5	0.064
50200561	Deep Uinta Overpressured Continuous Oil	Uinta-Piceance	2000	0.003	0.045	0.45	0.059
50440165	Spraberry Continuous Oil	Permian Basin	2007	0.001	0.045	0.4	0.057
50490170	Eagle Ford Shale Oil	Gulf Coast Mesozoic	2010	0.002	0.03	1	0.055
50490168	Austin Pearsall-Giddings Area Oil	Gulf Coast Mesozoic	2010	0.002	0.04	0.5	0.055
50330361	Niobrara Continuous Oil	Powder River Basin	2002	0.002	0.028	0.5	0.042
50330261	Mowry Continuous Oil	Powder River Basin	2002	0.002	0.025	0.35	0.035
50340262	Mowry Fractured Shale Continuous Oil	Big Horn Basin	2008	0.002	0.025	0.35	0.035
50390261	Fractured Niobrara Limestone (Silo Field Area)	Denver Basin	2001	0.002	0.022	0.4	0.033
50390661	Niobrara-Codell (Wattenberg Area)	Denver Basin	2001	0.003	0.008	0.1	0.011

Results

The results are presented in figures 1 through 4. Each line shows the range of EURs for a single AU. Only those EURs greater than the minimum assessed value (for that particular AU assessment) are included. Individual AU distributions show approximately two orders of magnitude difference between the smallest and largest EURs within a single AU. This range would be even larger if the distributions were not truncated.

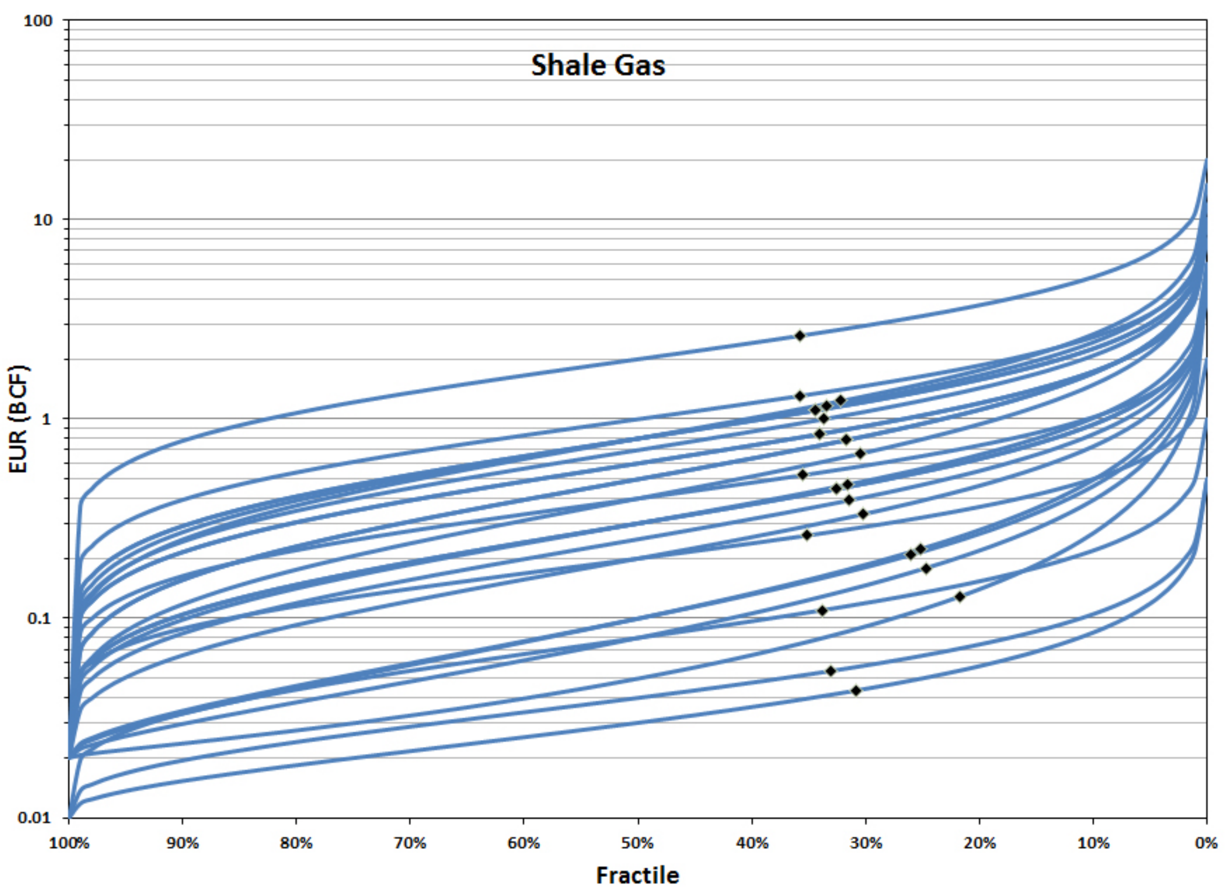

Figure 1. Cloud plot for United States shale-gas assessment units. Each curve represents one assessment unit and is based on the input data in table 1. Black diamonds indicate the mean value for each curve. [AU, assessment unit; EUR, estimated ultimate recovery; and BCF, billions of cubic feet]

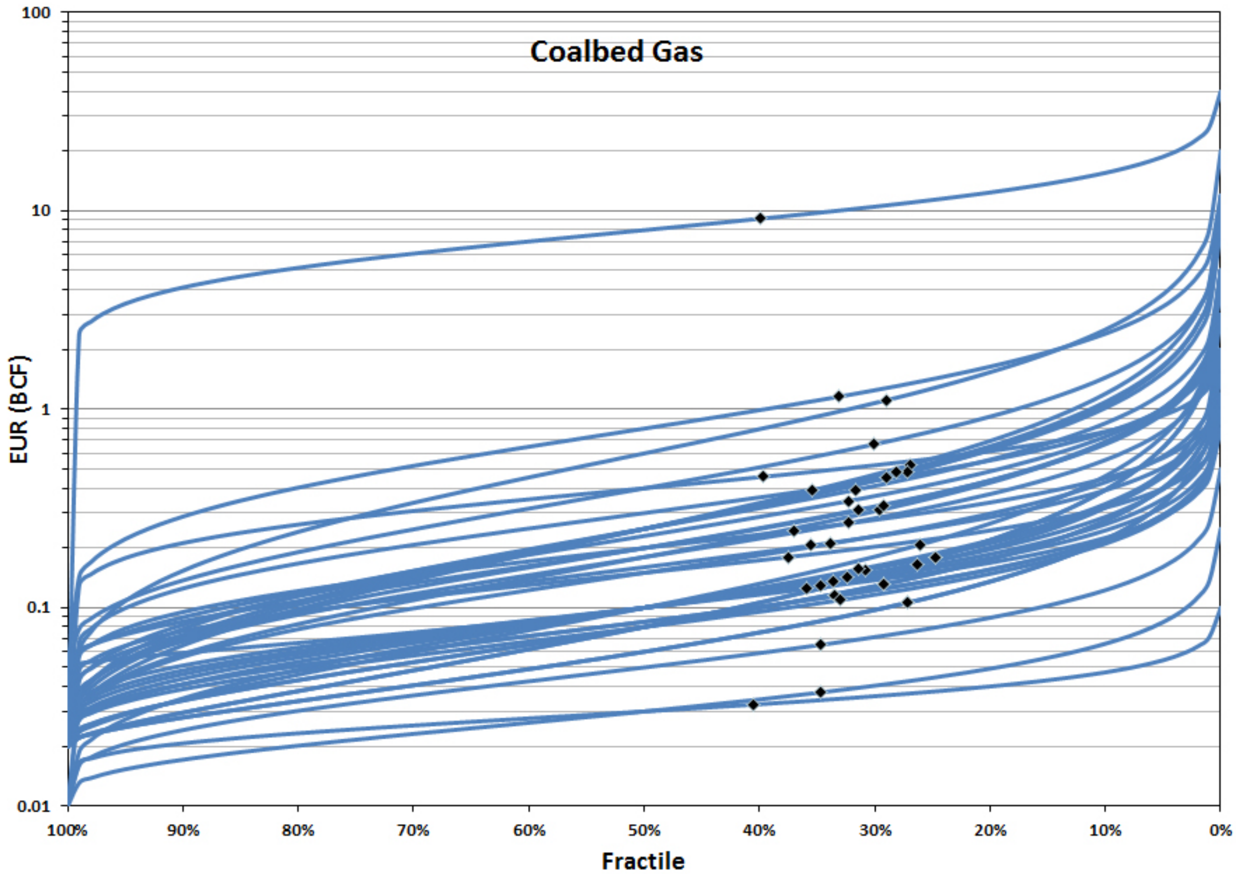

Figure 2. Cloud plot for United States coalbed-gas assessment units. Each curve represents one assessment unit and is based on the input data in table 2. Black diamonds indicate the mean value for each curve. [AU, assessment unit; EUR, estimated ultimate recovery; and BCF, billions of cubic feet]

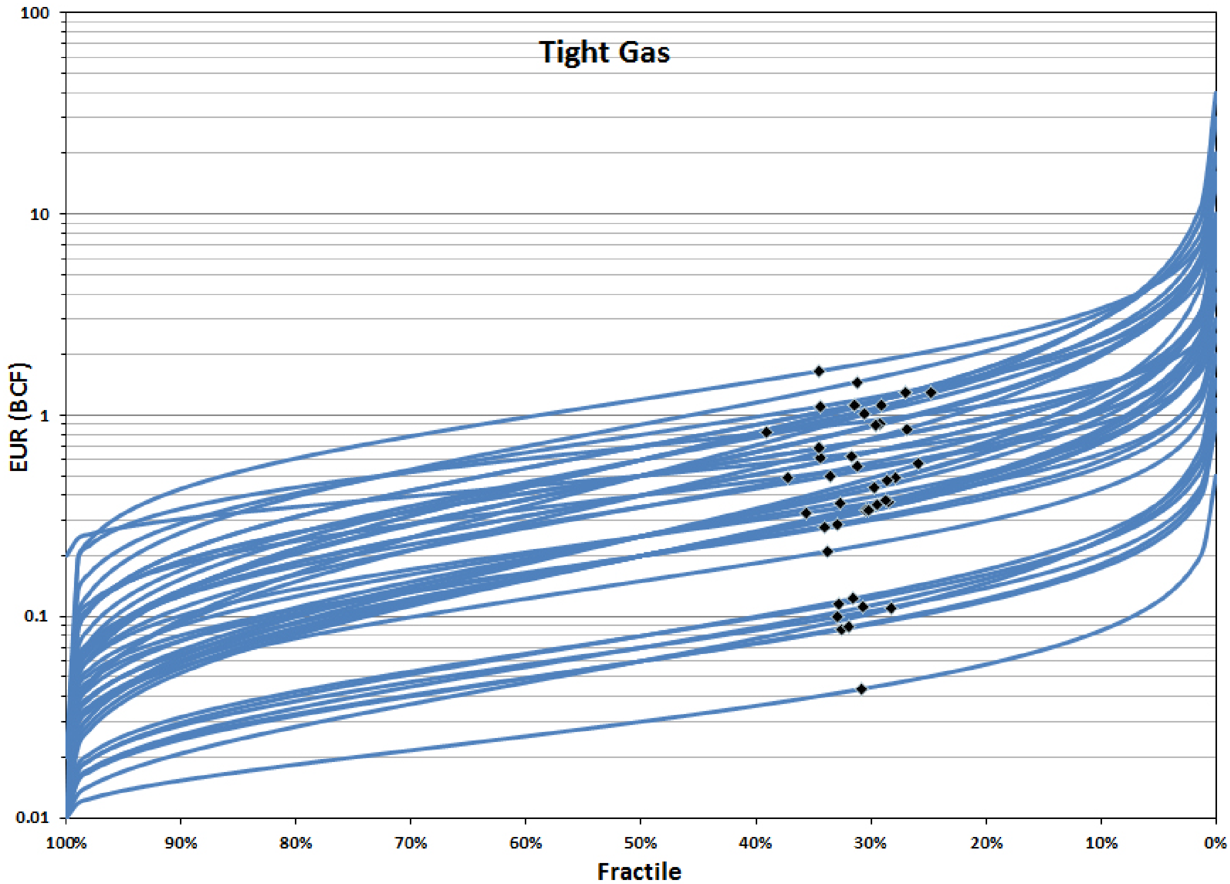

Figure 3. Cloud plot for United States tight-gas assessment units. Each curve represents one assessment unit and is based on the input data in table 3. Black diamonds show the mean value for each curve. [AU, assessment unit; EUR, estimated ultimate recovery; and BCF, billions of cubic feet]

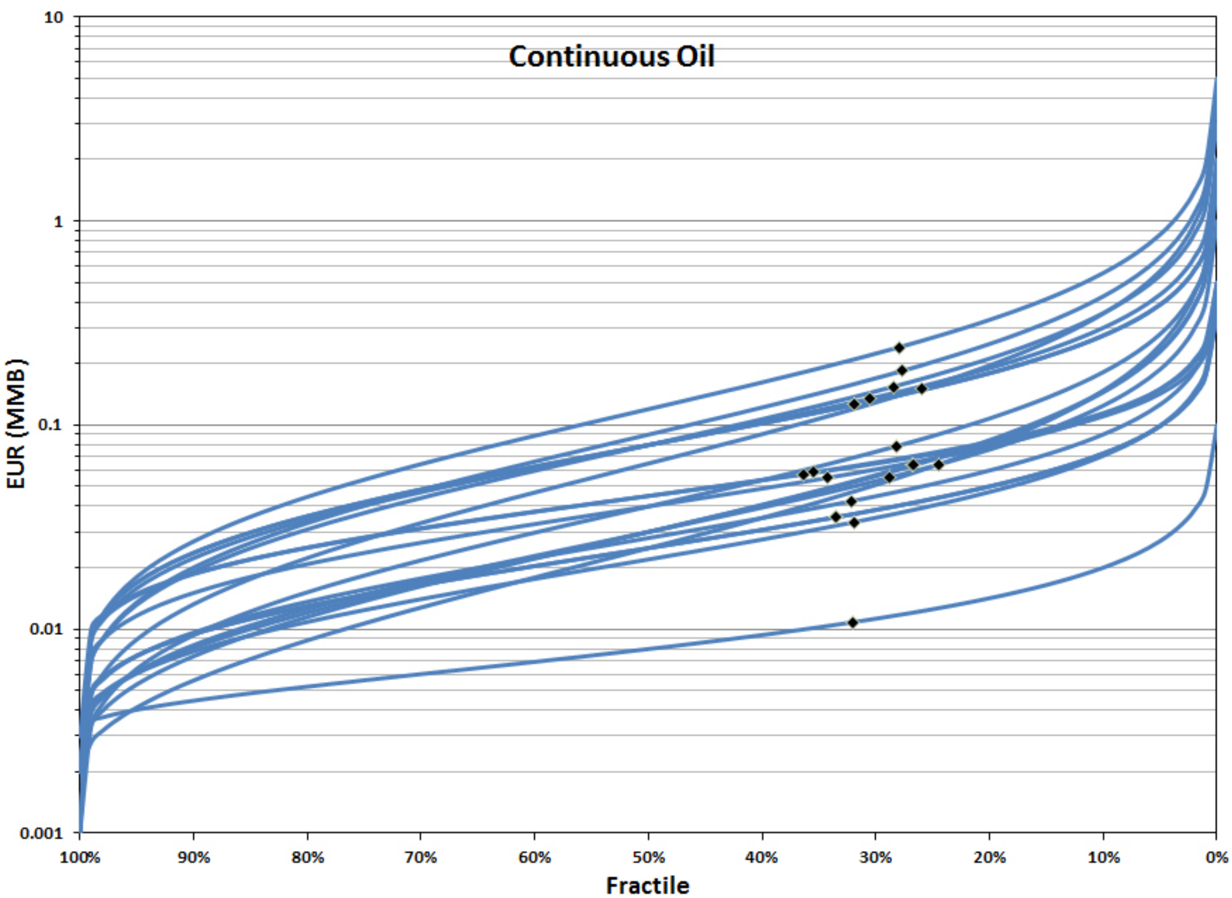

Figure 4. Cloud plot for United States continuous-oil assessment units. Each curve represents one assessment unit and is based on the input data in table 4. Black diamonds indicate the mean value for each curve. [AU, assessment unit; EUR, estimated ultimate recovery; and MMB, millions of barrels]

Each figure shows the EUR curves for a single category (shale gas, coalbed gas, tight gas, and continuous oil), allowing comparison of EUR distributions among AUs. The four figures are termed "cloud plots," which show the "cloud" of data representing the distribution of EUR distributions. Cloud plots of the distributions of drilled wells show similar ranges of variability.

Individual cloud plots show the wide variability among AUs of a particular category. The most productive AUs have average EURs from 22 to almost 300 times those of the least productive AUs. Also note the strong similarity of the shale gas and tight gas clouds (figs. 1, 3).

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Fisheries

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VOL 38 NO 1
JAN 2013

Hydraulic Fracturing: Will There Be Impacts?

What Hatchery Fish Don't Remember

The World's First Ecological Observatory

Fish? Why Fish?

New AFS Policy Statement!

AFS's Role In Education

03632415(2013)38(1)

Pushing the Limits: Using VIE to Identify Small Fish

Most tags just don't fit in small-bodied and early life stages of fish, but we still need to identify them, preferably without biasing our data. The options are further limited when many batches or individual identification is required. Visible Implant Elastomer™ (VIE) is internally injected but remains externally visible, and because the size of a tag is controlled by the tagger, it is easily adapted to very small fish. Colors and tag locations can be combined to create a coding scheme.

VIE has been used to tag newly settled coral reef fishes as small as 8—10 mm [1,2] with high tag visibility and little mortality. Marking success was influenced by depth of subcutaneous tag injection, anatomical location of the tag, pigmentation of the skin, and investigator's experience with the technique. Long-bodied fish like eels and lamprey as small as 1 g are easily tagged with VIE [3, 4].

Techniques for tagging very small salmonids have been developed for VIE. Brown trout ≤26 mm can be tagged at the base of the fins and have been recovered during stream surveys up to 83 days later[5]. This technique worked well with Atlantic Salmon ≤30 mm, and has been used for monitoring in-stream movements through snorkel surveys[6]. The minimum size for tagging juvenile salmonids has been pushed down to 22 mm FL, and is possible to tag alevins in the yolk sac[7], and fry in the fins[8].

VIE is well-suited for tagging juveniles of many other species and is used world wide. Please contact us if we can help with your project.

Photos: A syringe is used to inject VIE into the fin of a juvenile salmonid (top). VIE is available in 10 colors (left), of which six fluoresce under a VI Light for improved visibility and tag detection (center). Tagging rainbow trout fry as small as 22 mm is possible with VIE (below). Leblanc & Noakes[7] used this to identify fish originating from larger eggs (top) or smaller eggs (bottom).

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Photo courtesy C. Leblanc.

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Cover: Brook Trout in front of a Hydraulic Fracturing Pad.
Photo Credits: foreground: Miles Luo; background: Alessandro Farsi

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The American Fisheries Society (AFS), founded in 1870, is the oldest and largest professional society representing fisheries scientists. The AFS promotes scientific research and enlightened management of aquatic resources for optimum use and enjoyment by the public. It also encourages comprehensive education of fisheries scientists and continuing on-the-job training.

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COLUMN
President's Hook

Teach Your Children Well

John Boreman, President

AFS President Boreman may be contacted at: John.Boreman@ncsu.edu

This is an exciting time to be a member of the American Fisheries Society (AFS). Conservation laws, technology, and the questions being asked of fisheries professionals are changing rapidly, as well the nature of the fisheries discipline itself. In the past 20 years we have witnessed increased accountability requirements for those managing our fisheries resources, not only in the United States but also globally, putting more responsibility on the shoulders of fisheries professionals. We have seen the Internet and associated social media become a mainstay in communications among fisheries professionals and for keeping us in touch with decision makers and the public in general. We have seen computational power and associated data storage requirements increase by orders of magnitude, along with the development and use of sensors to measure the environment and its biota. Today's students (and many of today's faculty) were not yet born when our astronauts walked on the moon, when we used transistors in our radios, and spun 45s on our record players. I was shocked when none of the students in my class ever heard of FORTRAN. What's in store for fisheries professionals the next 20 years? Will we be able to adapt to changes in everything affecting our lives and livelihoods? Will we be adequately prepared to do so?

As a professional society, the AFS has a role to play in ensuring that people entering the future workforce will be prepared to tackle the issues that fisheries professionals will then be facing. This role is codified in the AFS Strategic Plan for 2010–2014:

> *Guide colleges and universities to maintain, modify, or develop curricula of the highest quality for both undergraduate and graduate students that provide an array of courses and experiences needed to effectively manage and conserve fisheries resources and meet the needs of employers.*

In keeping with my theme "Preparing for the Challenges Ahead," I have established an AFS Special Committee on Educational Requirements, chaired by AFS Second Vice President Ron Essig, to accomplish several tasks. First, the committee will assemble a list of North American colleges and universities currently offering undergraduate and graduate degrees in fisheries-related disciplines (e.g., fisheries science, fisheries biology, fisheries ecology, fisheries management, fisheries policy, and fisheries economics) and publish the list on the AFS website. Concurrently, the committee will oversee a survey of major employers that will be hiring graduates with degrees in fisheries-related disciplines in the next 5–10 years to determine what coursework those graduates will be expected to have taken that would be most germane to the positions being filled. The survey results, and an evaluation of their implications, should be published in *Fisheries*. When the list and survey are completed, the committee will compare the coursework expectations of the employers with the current coursework requirements of a selected subset of colleges and universities offering fisheries degrees. If the comparison indicates a misalignment, the committee will recommend ways in which an alignment can be made, which could range from giving simple advice to the colleges and universities to instituting an accreditation program administered by the AFS (or something in between). The recommendations could serve as the basis for discussion at an upcoming AFS Governing Board retreat.

I have also asked the special committee to compare coursework expectations resulting from the survey to degree requirements for certification as a fisheries professional, working with the Education Subcommittee of the AFS Board of Professional Certification, as well as to the U.S. Office of Personnel Management's educational requirements in the grade-level qualification standards for the 482 (Fish Biology) series. Based on the comparisons, the committee could recommend changes that would bring the degree requirements for certification and federal employment into alignment with employer expectations. The committee might also look at analogous requirements for federal employment of fisheries professionals in Mexico and Canada. These comparisons can be published as a series of articles in *Fisheries*.

Continuing education, which helps fisheries professionals shore up their level of skill, knowledge, and expertise as employment demands evolve, is also important in preparing the future workforce. To this end, I have charged the AFS Continuing Education Committee to assist AFS staff in expanding opportunities for distance education (i.e., education via the Internet) beyond virtual attendance at continuing education courses offered at the annual meeting. One option the Continuing Education Committee will be tackling through the AFS will be to pilot at least one half-day short course in the coming year to be offered via a webinar. The pilot short course could be offered for free to alleviate complications with registration and fees and allow the committee to focus evaluation of the pilot solely on the quality of the learning experience. Given successful delivery of the pilot course, the AFS could pursue, for example, a quarterly distance education webinar series that may or may not require

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Hydraulic Fracturing and Brook Trout Habitat in the Marcellus Shale Region: Potential Impacts and Research Needs

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ABSTRACT: *Expansion of natural gas drilling into the Marcellus Shale formation is an emerging threat to the conservation and restoration of native brook trout (*Salvelinus fontinalis*) populations. Improved drilling and extraction technologies (horizontal drilling and hydraulic fracturing) have led to rapid and extensive natural gas development in areas overlying the Marcellus Shale. The expansion of hydraulic fracturing poses multiple threats to surface waters, which can be tied to key ecological attributes that limit brook trout populations. Here, we expand current conceptual models to identify three potential pathways of risk between surface water threats associated with increased natural gas development and life history attributes of brook trout: hydrological, physical, and chemical. Our goal is to highlight research needs for fisheries scientists and work in conjunction with resource managers to influence the development of strategies that will preserve brook trout habitat and address Marcellus Shale gas development threats to eastern North America's only native stream salmonid.*

Ruptura hidráulica y el hábitat de la trucha de arrollo en la región de Marcellus Shale: impactos potenciales y necesidades de investigación

RESUMEN: El crecimiento de las actividades de perforación de gas natural en la formación Marcellus Shale es una amenaza emergente para la conservación y restauración de las poblaciones nativas de la trucha de arroyo (*Salvelinus fontinalis*). La perforación más eficiente y las tecnologías de extracción (perforación horizontal y ruptura hidráulica) han facilitado el rápido y extensivo desarrollo de esta industria a las áreas que comprende la región Marcellus Shale. La expansión de las rupturas hidráulicas representa múltiples amenazas a las aguas superficiales, que pueden estar asociadas a atributos ecológicos clave que limitan las poblaciones de la trucha de arroyo. En la presente contribución se expanden los modelos conceptuales actuales que sirven para identificar tres fuentes potenciales de riesgo entre las amenazas a las aguas superficiales asociadas al creciente desarrollo del gas natural y los atributos de la historia de vida de la trucha de arroyo; atributos hidrológicos, físicos y químicos. El objetivo de este trabajo es hacer notar las necesidades de investigación para los científicos pesqueros y trabajar junto con los manejadores de recursos para influir en el desarrollo de estrategias tendientes a preservar el hábitat de la trucha de arroyo; así mismo se atienden las amenazas que representa el desarrollo de la industria del gas natural para el único salmónido nativo de América del norte.

INTRODUCTION

Hydraulic Fracturing in the Marcellus Shale

Natural gas extraction from subterranean gas-rich shale deposits has been underway in the northeastern United States for almost 200 years but has expanded rapidly over the past decade within the Devonian Marcellus Shale formation (P. Williams 2008). This expansion has largely been driven by the development and refinement of the horizontal hydraulic fracturing process (United States Energy Information Administration 2011a). Horizontal gas drilling differs from the more traditional vertical drilling process because the well is drilled to the depth of the shale stratum and then redirected laterally, allowing for access to a larger area of subterranean shale (Figure 1). Drilling is followed by the hydraulic fracturing process, which involves injecting a chemically treated water-based fluid into the rock formation at high pressure to cause fissures in the shale and permit the retrieval of gas held within the pore space of the shale. The fissures are kept open by sand and other proppants, which allow gas to be extracted (Soeder and Kappel 2009; Kargbo et al. 2010). The hydraulic fracturing process was granted exemptions to the Clean Water and the Safe Drinking Water Acts under the Energy Policy Act of 2005. Drilling has since expanded rapidly in the Marcellus Shale deposit in portions of West Virginia and Pennsylvania (Figure 2), is expected to continue into Ohio and New York, and will likely continue to expand within these states to include the gas-bearing Utica Shale formation.

Brook Trout Status within the Marcellus Shale

Eastern brook trout are native to the Eastern United States, with a historic range extending from the southern Appalachians in Georgia north to Maine (MacCrimmon and Campbell 1969; Figure 2). Brook trout require clean, cold water (optimal tem-

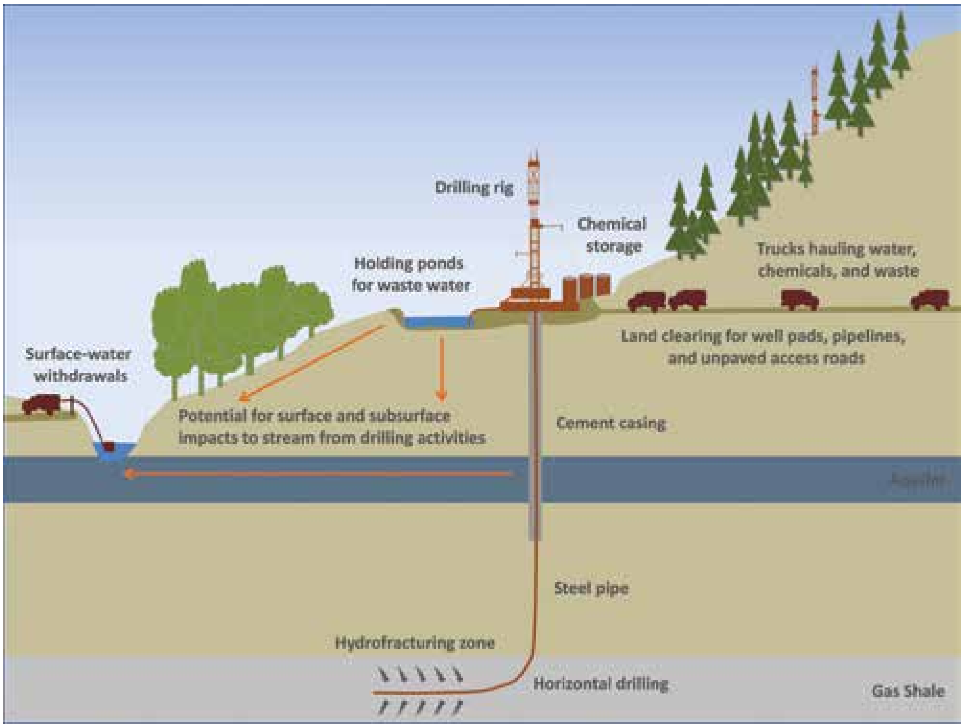

Figure 1. Conceptual diagram depicting the hydraulic fracturing process. A rig drills down into the gas-bearing rock and the well is lined with steel pipe. The well is sealed with cement to a depth of 1,000 ft. to prevent groundwater contamination. The well is extended horizontally 1,000 ft. or more into the gas-bearing shale where holes are blasted through the steel casing and into the surrounding rock. Sand, water, and chemicals are pumped into the shale to further fracture the rock and gas escapes through fissures propped open by sand particles and back through the well up to the surface. Supporting activities include land clearing for well pads and supporting infrastructure, including pipelines and access roads. Trucks use roads to haul in water extracted from local surface waters, chemicals, and sand. Recovered water is stored in shallow holding ponds until it can be transported by truck to treatment facilities or recycled to fracture another well. These activities may impact nearby streams through surface and subsurface pathways.

perature = 10–19°C), intact habitat, and supporting food webs to maintain healthy populations, making them excellent indictors of anthropogenic disturbance (Hokanson et al. 1973; Lyons et al. 1996; Marschall and Crowder 1996). Only 31% of subwatersheds (sixth level, 12-digit hydrological units [HUC12], as defined by the Watershed Boundary Dataset; U.S. Department of Agriculture, Natural Resources Conservation Service 2012) within the historic range of brook trout are currently expected to support intact populations (self-sustaining populations greater than 50% of the historical population; Hudy et al. 2008). Substantial loss of brook trout populations within their native range is due to anthropogenic impacts that have resulted in habitat fragmentation and reduction, water quality and temperature changes, and alteration of the biological environment through introduction and removal of interacting species (Hudy et al. 2008). Conservation efforts, including formation of the Eastern Brook Trout Venture (Eastern Brook Trout Joint Venture [EBTJV] 2007, 2011) and a shift by organizations such as Trout Unlimited (TU) to policies that oppose the stocking of nonnative hatchery-produced salmonids in native trout streams (TU 2011), are focused on maintaining and restoring brook trout populations in their native range. With these growing concerns about the future of native brook trout populations, natural gas well development within the Marcellus Shale region presents another potential threat to native brook trout populations.

Twenty-six percent of the historic distribution of brook trout habitat overlaps with the Marcellus Shale (Figure 2). The Pennsylvania portion of the Marcellus Shale has experienced the largest increase in natural gas development (Figure 2). Between January 1, 2005, and May 31, 2012, the cumulative number of Marcellus Shale well permits issued in Pennsylvania increased from 17 to 11,784 (Pennsylvania Department of Environmental Protection [PADEP] 2012a). Of these permitted wells, 5,514 were drilled during the same time period (PADEP 2012b; Figure 3A). Trends in drilled well densities among subwatersheds during the rapid expansion of drilling activity suggest that there have not been any extra protections granted during the well permitting process for subwatersheds that are expected to support intact brook trout populations (Figure 3B). Fifty-four of the 134 subwatersheds categorized as having intact brook trout populations within the Marcellus Shale region have already experienced drilling activity (Hudy et al. 2008). Overall, Marcellus drilling activity has expanded to 377 subwatersheds (mean area = 94.8 ± 1.9 km^2) in Pennsylvania (Figure 4). Within these 377 subwatersheds, patterns in well density over time show similar trends among subwatersheds varying in their current brook trout population status (Figure 3B). Though there is a significant difference in current well densities among the three subwatershed types (one-way analysis of variance [Type II], $F_{2,\,292} = 4.14$, $P = 0.02$), mean well density does not differ between subwatersheds where brook trout are extirpated/unknown and those with intact brook trout populations (Tukey's multiple comparison test, $\alpha = 0.05$; Figure 3B). In fact, the two highest drilling densities include an extirpated/unknown subwatershed (16.7 wells/10 km^2) and a subwatershed expected to support intact brook trout populations (15.1 wells/10 km^2; Figure 4). These trends highlight that increasing hydraulic fracturing development is occurring not only in degraded subwatersheds but also in those that support an already vulnerable native species and valuable sport fish. This trend should be of concern to fisheries scientists, managers, and conservationists who work to maintain and improve the current status of this natural heritage species.

Linking Marcellus Shale Drilling Impacts to Brook Trout Population Health

Recent efforts to conceptualize horizontal hydraulic fracturing impacts have focused on stream ecosystems and regional

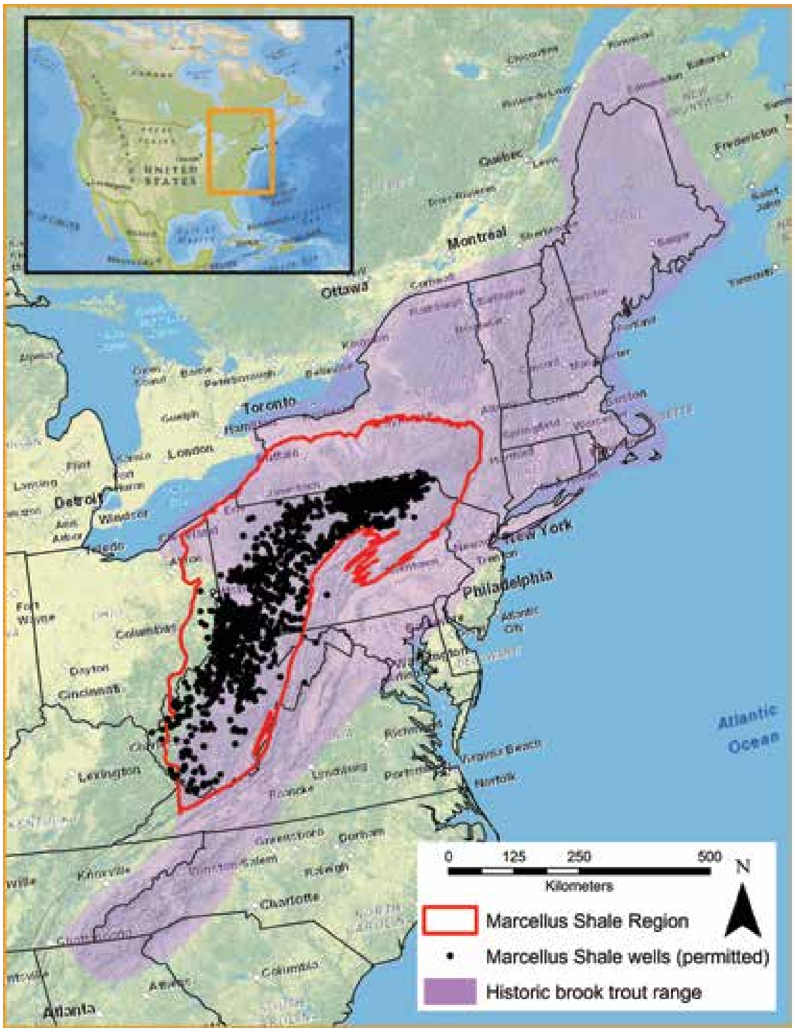

Figure 2. Overlay of the Marcellus Shale region of the Eastern United States (U.S. Geological Survey [USGS] 2011) and the historic distribution of eastern brook trout (Hudy et al. 2008) with permitted Marcellus Shale well locations, 2001–2011 (Ohio Department of Natural Resources 2011; West Virginia Geological and Economic Survey 2011; PADEP 2012a).

water supplies but not on potential pathways to particular target organisms. Herein, we integrate two existing conceptual models of potential natural gas development impacts to surface waters and link them to different brook trout life history attributes (Entrekin et al. 2011; Rahm and Riha 2012). Entrekin et al.'s (2011) conceptual model establishes connections between hydraulic fracturing activities and the ecological endpoint of stream ecosystem structure and function by way of potential environmental stressors from drilling activity sources. These stressors to stream ecosystems can be planned activities that must necessarily occur in the hydraulic fracturing process (deterministic events) or those that may occur unexpectedly (probabilistic events; Rahm and Riha 2012). Brook trout have different environmental requirements at the various stages of their life cycle and may be sensitive to potential impacts associated with the current expansion of hydraulic fracturing; thus, understanding the environmental stressors associated with hydraulic fracturing has implications for fisheries conservation, including maintenance and/or enhancement of native brook trout populations.

We delineated relationships between various stream ecosystem attributes that are potentially impacted by increased drilling activities and different aspects of the brook trout life cycle (Figure 5). A review of extant literature on the activities associated with natural gas drilling and other extractive industries and of the environmental changes known to directly influence brook trout at one or more of their life stages identified three primary pathways by which increased drilling will likely impact brook trout populations. The primary pathways include (1) changes in hydrology associated with water withdrawals; (2) elevated sediment inputs and loss of connectivity associated with supporting infrastructure; and (3) water contamination from introduced chemicals or wastewater (Entrekin et al. 2011; Rahm and Riha 2012). These three pathways may be considered natural gas drilling threats to brook trout populations that require study and monitoring to fully understand, minimize, and abate potential impacts.

PATHWAY #1: WITHDRAWALS → HYDROLOGY → BROOK TROUT

Two to seven million gallons of water are needed per hydraulic fracturing stimulation event; a single natural gas well can be fractured several times over its lifespan, and a well pad site can host multiple wells (Soeder and Kappel 2009; Kargbo et al. 2010). This large volume of water needed per well, multiplied by the distributed nature of development across the region, suggests that hydraulic fracturing techniques for natural gas development can put substantial strain on regional water supplies. This level of water consumption has sparked concern among hydrologists and aquatic biologists about the sourcing of the water, as well as the implications for available habitat and other hydrologically influenced processes in adjacent freshwater ecosystems (Entrekin et al. 2011; Gregory et al. 2011; Baccante 2012; Rahm and Riha 2012; Figure 5). Surface water is the primary source for hydraulic fracturing–related water withdrawals in at least one major basin intersecting the Marcellus Shale region (Susquehanna River Basin Commission [SRBC] 2010), but groundwater has been a major water source in other natural gas deposits such as the Barnett Shale region in Texas (Soeder and Kappel 2009). The cumulative effects of multiple surface and/or groundwater withdrawals throughout a watershed have the potential to effect downstream hydrology and connectivity of brook trout habitats (Rahm and Riha 2012; Petty et al. 2012).

Aquatic habitat is particularly limited by low-flow periods during the summer for fish and other aquatic organisms (Figure 6). Changes in temperature and habitat volume during summer low-flow periods are primary factors limiting brook trout populations (Barton et al. 1985; Wehrly et al. 2007; Xu et al. 2010). Brook trout rely on localized groundwater discharge areas within pools and tributary confluences to lower body temperature below that of the ambient stream temperature during warm periods, and groundwater withdrawals can alter these temperature refugia. Additionally, access to thermal refugia may be limited by loss of connectivity associated with reduced flows between temperature refugia (headwater streams, seeps, tributary confluences, groundwater upwellings) and larger stream habitats (Petty et al. 2012). Reduced flows, particularly coldwater inputs, may inhibit growth rates by reducing feeding activity of both juveniles and adults or inducing sublethal heat shock at temperatures above 23°C and lethal effects at 24–25°C (7-day upper lethal temperature limit; Cherry et al. 1977; Tangiguchi et al. 1998; Baird and Krueger 2003; Lund et al. 2003; Wehrly et al. 2007). Recovery from thermal stress responses (heat shock) can be prolonged (24–48 h) even if exposure to high stream temperatures is relatively short (1 h) but may be more than 144 h when exposed to high temperatures for multiple days (Lund et al. 2003). Adult abundance and biomass of brook trout in run habitats declines with flow reduction and carrying capacity is likely limited by available pool area during low-flow periods (Kraft 1972; Hakala and Hartman 2004; Walters and Post 2008).

Reduction in surface water discharge during summer months may also indirectly impact brook trout growth by decreasing macroinvertebrate prey densities (Walters and Post 2011) in small streams and lowering macroinvertebrate drift encounter rates for drift-feeding salmonids (Cada et al. 1987; Nislow et al. 2004; Sotiropoulos et al. 2006; Figure 5). Other indirect effects may include increasing interspecific competition through habitat crowding, especially with more tolerant competitor species such as brown trout (*Salmo trutta*) and rainbow trout (*Oncorhynchus mykiss*), due to decreased habitat availability and increased temperature during low-flow periods. Introduced brown trout tend to out-compete brook trout for resources and have higher growth rates in all but the smallest, coldest headwater streams (Carlson et al. 2007; Öhlund et al. 2008; Figure 5). Additionally, salmonids may be more susceptible to disease or infestation of parasites when the temperature of their environment is not consistent and adequately cool (Cairns et al. 2005), a problem that could be exacerbated by the crowding in pool habitats that can occur as a result of flow reductions (Figure 5). Sediment accrual in redds can limit recruitment (Alexander and Hansen 1986; Argent and Flebbe 1999), and adequate summer base flows coupled with occasional high flow pulses are important for preparing sediment free spawning redds (Hakala and Hartman 2004). DePhilip and Moberg (2010) demonstrated that the magnitude of withdrawals proposed by drilling companies in the Susquehanna River basin has the potential to impact summer and fall low flows, and in some cases, high-flow events (Q_{10}) in small streams.

Water withdrawals may also impact brook trout spawning activities and recruitment during higher flow periods (Figures 5 and 6). Brook trout peak spawning activity typically occurs at the beginning of November in gravel substrates immediately downstream from springs or in places where groundwater seepage enters through the gravel (Hazzard 1932). Withdrawals during the fall may dewater and reduce available spawning habitat, particularly during low-flow years. Additionally, stable base

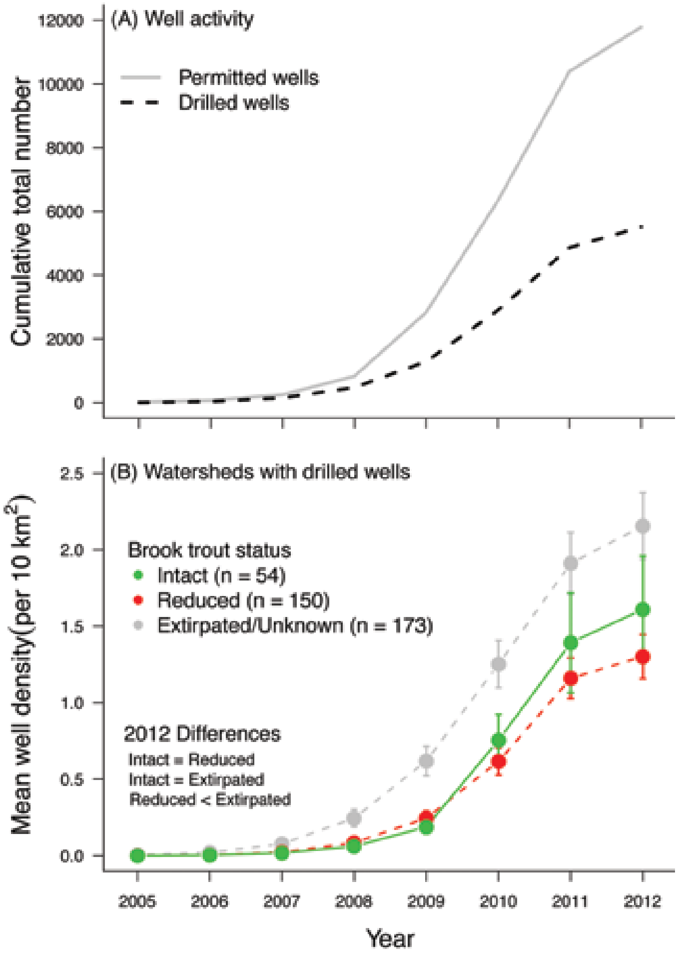

Figure 3. Well permitting and drilling in the Pennsylvania portion of Marcellus Shale from January 1, 2005, through May 31, 2012. (A) Cumulative number of permitted and drilled wells over time. (B) Mean well density (wells per 10 km²) over time for 377 actively drilled HUC12 subwatersheds, grouped by status of brook trout population (Hudy et al. 2008). Permitted and drilled Marcellus well data are from PADEP (2012a, 2012b), respectively.

flows after spawning are necessary for maintaining redds during egg incubation throughout winter (Figure 6). Maintaining base flow in trout spawning habitats throughout the incubation period maintains shallow groundwater pathways, chemistry, and flow potentials in redds (Curry et al. 1994, 1995), which protect developing eggs from sedimentation (Waters 1995; Curry and MacNeill 2004) and freezing (Curry et al. 1995; J. S. Baxter and McPhail 1999). Thus, insuring that water withdrawals required for hydraulic fracturing do not interrupt stable winter base flows in small coldwater streams is an important consideration in protecting brook trout recruitment in the Marcellus Shale region (Figures 5 and 6).

PATHWAY #2: INFRASTRUCTURE → PHYSICAL HABITAT → BROOK TROUT

Natural gas extraction requires development of well pad sites and infrastructure for transportation and gas conveyance, which involves a set of activities that will likely have impacts on water quality and habitat quality for brook trout unless proper precautions and planning are implemented. These activities

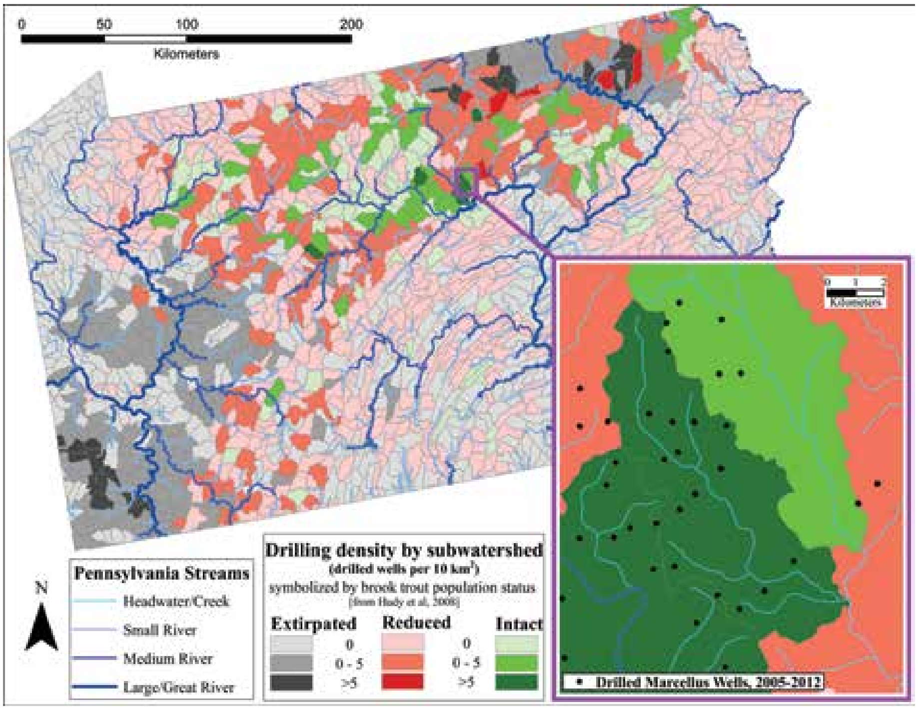

Figure 4. Density of wells drilled in the Pennsylvania portion of the Marcellus Shale by HUC12 subwatershed (well drilling locations from PADEP 2012b; 12-digit HUC subwatershed boundaries and areas from USGS Watershed Boundary Dataset; U.S. Department of Agriculture, Natural Resources Conservation Service 2012), symbolized by status of current brook trout population (Hudy et al. 2008). Inset: A subwatershed expected to support an intact brook trout population that currently has the second highest well density (15.1 wells/10 km2) of all drilled subwatersheds.

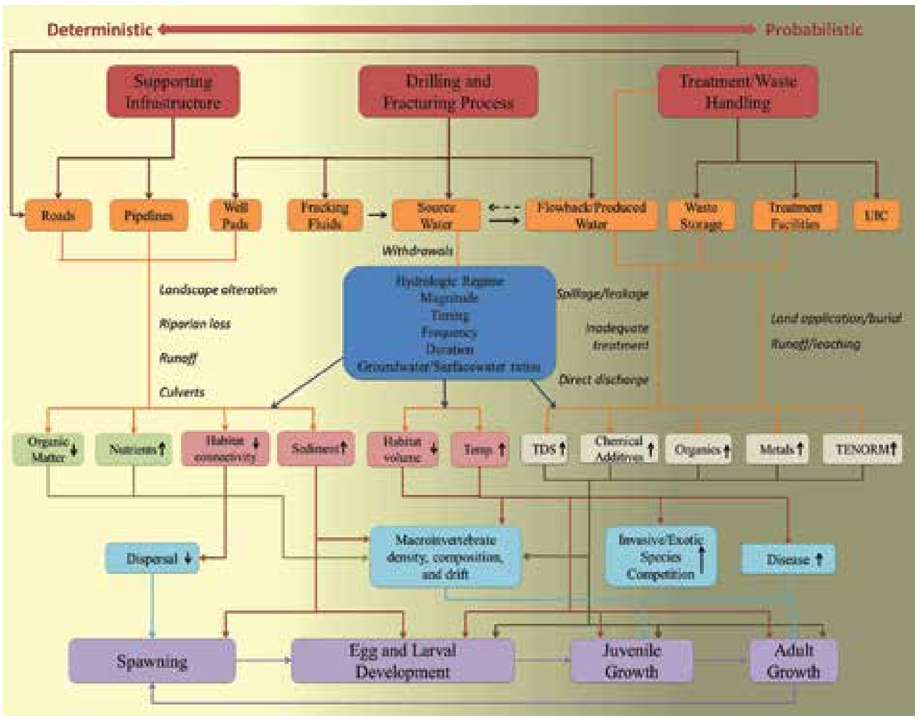

Figure 5. Conceptual model of relationships between hydraulic fracturing drilling activities and the life cycle of eastern brook trout (modified from conceptual models based on Entrekin et al. [2011] and Rahm and Riha [2012]).

include, but are not limited to, construction of well pads, roadways, stream crossings, and pipelines; increased use of existing rural roadways for transportation of equipment, source water, recycled flow-back, and wastes associated with hydraulic fracturing activities; and storage of these same materials (Figure 1). Increased sediment loads and loss of stream connectivity are some of the stream impacts associated with these deterministic activities, which could reduce habitat quality and quantity needed for brook trout spawning success, egg development, larval emergence, and juvenile and adult growth and survival (Figure 5).

Brook trout are particularly sensitive to the size and amount of sediment in streams, with coarse gravel providing a more suitable substrate than fine particles (Witzel and MacCrimmon 1983; Marschall and Crowder 1996). Well pad site, access road, and pipeline corridor construction require land clearing, which can mobilize from tens to hundreds of metric tons of soil per hectare (H. Williams et al. 2008; Adams et al. 2011). Pipeline construction (Reid et al. 2004) and unpaved rural roadways (Witmer et al. 2009) crossing streams can trigger additional sediment inputs to streams. Road and well pad densities have been found to be positively correlated with fine sediment accumulation in streams (Opperman et al. 2005; Entrekin et al. 2011), which disrupts fish reproduction and can lead to mortality (Taylor et al. 2006). Overall, trout populations have been found to decline in abundance, even with small increases in stream sediment loads (Alexander and Hansen 1983, 1986). Sediment can impact all stages of trout life cycles, because turbidity reduces foraging success for adults and juveniles (Sweka and Hartman 2001), and sediment accumulation can cause oxygen deprivation in salmonid redds and reduce successful emergence of larvae from eggs (Witzel and MacCrimmon 1983; Waters 1995; Argent and Flebbe 1999; Curry and MacNeill 2004; Figure 5).

The spatial and temporal extent of sediment impacts to streams is linked to the scale and persistence of mobilizing activities. For example, localized events, such as construction of culverts

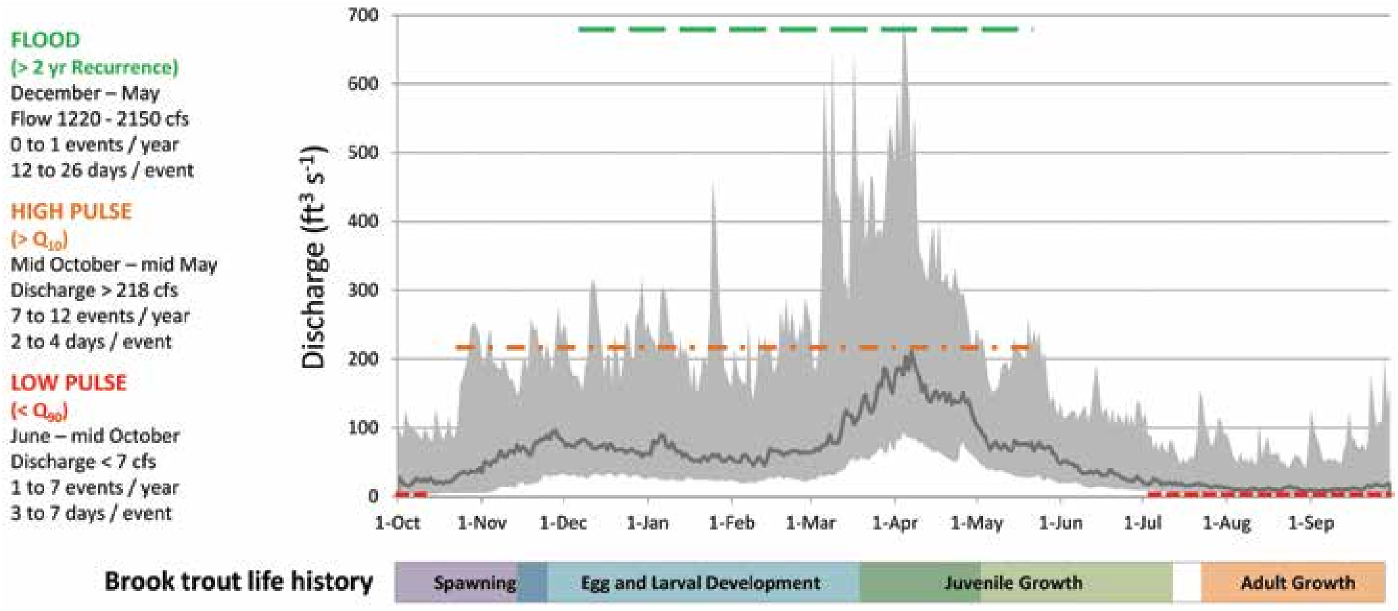

Figure 6. Hydrologic patterns for a trout supporting stream with relatively unaltered hydrology (Little Delaware River, USGS Gage 01422500, watershed area = 129 km2) in relation to timing of brook trout life history periods. Median (dark line), bounded by 10th and 90th percentile daily flows (grey) for 47 years of discharge data. Important flood, high-, and low-flow components were computed and described using Indicators of Hydrologic Alteration (The Nature Conservancy 2009).

at stream road crossings can increase sediment loads for up to 200 m downstream of the culvert over a 2- to 3-year period (Lachance et al. 2008). Conversely, the sediment loads associated with more diffuse land clearing activities and frequent and sustained access into rural areas by large vehicles can contribute to reductions in brook trout biomass and densities and shifts in macroinvertebrate communities that last approximately 10 years (VanDusen et al. 2005).

Sedimentation from drilling infrastructure development can further impact brook trout indirectly by reducing the availability of prey (Figure 5): high sediment levels reduce species richness and abundance of some aquatic macroinvertebrates (Waters 1995; Wohl and Carline 1996; VanDusen et al. 2005; Larsen et al. 2009), with high sediment environments generally experiencing a shift from communities rich in mayflies (Ephemoptera), stoneflies (Plectoptera), and caddisflies (Trichoptera) to those dominated by segmented worms (Oligochaeta) and burrowing midges (Diptera: Chironmidae; Waters 1995). Riparian clearing can also diminish food sources for brook trout populations, which tend to depend heavily on terrestrial macroinvertebrates (Allan 1981; Utz and Hartman 2007). However, shifts in the prey base from shredder-dominated communities that support higher brook trout abundance to grazer-dominated communities have been observed in recently logged watersheds due to higher primary productivity associated with increased sunlight from sparser canopy cover (Nislow and Lowe 2006). Consequently, land clearing and infrastructure development will likely increase sediment loads, culminating in changes in composition and productivity of the invertebrate prey base for brook trout, although not all of these changes will necessarily be negative for brook trout (Figure 5).

Conveyance of hydraulic fracturing equipment and fluids, and the extracted natural gas, into and out of well pad sites often necessitates crossing streams with trucks and pipelines. Culvert construction for roadway and pipeline stream crossings, if not properly designed, can create physical barriers that fragment brook trout habitat and disrupt their life cycle by preventing movement of adult fish into upstream tributaries for spawning and repopulation of downstream habitat by new juveniles (Wofford et al. 2005; Letcher et al. 2007; Poplar-Jeffers et al. 2009; Figure 5). Barriers to connectivity negatively impact fish species richness (Nislow et al. 2011), and habitat fragmentation without repopulation can cause local population extinction (Wofford et al. 2005; Letcher et al. 2007). Additionally, connectivity between larger stream reaches that provide food resources during growth periods and small headwater streams that may serve as temperature refugia during warmer months is important for overall population health (Utz and Hartman 2006; Petty et al. 2012). For these reasons, land clearing activities, road densities, and culvert densities can have a negative impact on trout reproductive activity and overall population size (Eaglin and Hubert 1993; C. V. Baxter et al. 1999).

PATHWAY #3: CHEMICAL WASTE → WATER QUALITY→ BROOK TROUT

Probabilistic events during the drilling process such as runoff from well pads, leaching of wastewater from holding ponds, or spills of hydraulic fracturing fluids during transportation to processing sites can affect the chemical composition of streams (Rahm and Riha 2012). Although the specific chemical composition of fracturing fluids is typically proprietary information, voluntary reporting of the content of fracturing fluids to the FracFocus Chemical Disclosure Registry (a partnership between the Ground Water Protection Council [GWPC] and Interstate Oil and Gas Compact Commission [IOGCC], supported the U.S. Department of Energy [USDOE]) has become more common (USDOE 2011). Fracturing fluids are generally a mix of water and sand, with a range of additives that perform particular roles in the fracturing process, including friction reducers, acids, biocides, corrosion inhibitors, iron controls, cross-linkers, breakers, pH-adjusting agents, scale inhibitors, gelling agents, and surfactants (GWPC and IOGCC 2012). The wastewater resulting from the hydraulic fracturing process is high in total dissolved solids (TDS), metals, technologically enhanced naturally occurring radioactive materials (TENORM), and fracturing fluid additives (U.S. Environmental Protection Agency [USEPA] 2012). Increased metals and elevated TDS from probabilistic spill events, or deterministic events including direct discharge of treated flow-back water into streams, will likely have negative effects on stream ecosystems that support brook trout populations (Figure 5).

Elevated concentration of metals causes decreased growth, fecundity, and survival in brook trout. In particular, aluminum has been shown to cause growth retardation and persistent mortality across life stages (Cleveland et al. 1991; Gagen et al. 1993; Baldigo et al. 2007), chromium reduces successful emergence of larvae and growth of juveniles (Benoit 1976), and cadmium can diminish reproductive success by causing death of adult trout prior to successful spawning (Benoit et al. 1976; Harper et al. 2008). Trout normally exhibit avoidance behaviors to escape stream reaches that are overly contaminated with heavy metals; however, because brook trout are so heavily reliant on low-temperature environs, they seek out refugia of cold groundwater outflow even if the water quality is prohibitively low (Harper et al. 2009). Thus, if groundwater is contaminated and the groundwater-fed portions of a stream are receiving a significant contaminant load, brook trout might be recipients of high concentrations of those contaminants.

Total dissolved solids represent an integrative measure of common ions or inorganic salts (sodium, potassium, calcium, magnesium, chloride, sulfate, and bicarbonate) that are common components of effluent in freshwaters (Chapman et al. 2000). Elevated TDS and salinity may have negative effects on spawning and recruitment of salmonids by decreasing egg fertilization rates and embryo water absorption, altering osmoregulation capacity, and increasing posthatch mortality (Shen and Leatherland 1978; Li et al. 1989; Morgan et al. 1992; Stekoll et al. 2009; Brix et al. 2010). There is also evidence from western U.S. lakes with increasing TDS concentrations that growth and survival of later life stages may be negatively impacted as well (Dickerson and Vinyard 1999). Elevated salinities can lower salmonid resistance to thermal stress (Craigie 1963; Vigg and Koch 1980), which may influence competition between brook trout and more tolerant brown trout (Öhlund et al. 2008). There is a growing body of evidence supporting associations between declines in macroinvertebrate abundance, particularly mayflies, and increased TDS or surrogate specific conductivity related to mining activities within the Marcellus Shale region (Kennedy et al. 2004; Hartman et al. 2005; Pond et al. 2008; Pond 2010; Bernhardt and Palmer 2011). Overall, changes in TDS associated with improper handling or discharge of flow-back water will likely impact brook trout through direct and indirect pathways including changes in macroinvertebrate communities that serve as the prey base and/or the alteration of environmental conditions to those more favorable for harmful invasive species (i.e., Golden algae; Renner 2009; Figure 5).

A FRAMEWORK FOR ADDRESSING RESEARCH NEEDS

Our examination of potential impacts of hydraulic fracturing for natural gas extraction in the Marcellus Shale on brook trout populations reveals three key pathways of influence: hydrological, physical, and chemical. These pathways originate from the various activities associated with the hydraulic fracturing method of natural gas extraction and may affect brook trout at one or more stages of their life cycle through direct and indirect mechanisms (Figure 5). The hydrological pathway is the broadest in that it is influenced by events at both the surface and groundwater levels and, subsequently, it influences brook trout both directly through flow regimes and indirectly by also influencing physical and chemical pathways. The primary drilling activity driving the hydrological pathway is the need for source water for the hydraulic fracturing process. The physical habitat pathway originates from the infrastructural requirements of the natural gas extraction industry, which can be expected to increase stream sedimentation and impede brook trout at all life phases. The consequences of infrastructural development further impact brook trout populations if road-building activities and poorly designed road-crossing culverts reduce connectivity between spawning areas, temperature refugia, and downstream habitats. Finally, the chemical pathway addresses the potential for contamination of streams by the hydraulic fracturing fluids and wastewater. This contamination can have direct consequences for brook trout and their food resources. The hydrological and physical pathways are expected to result from planned (deterministic) hydraulic fracturing activities, and the chemical pathway may be triggered by both unplanned spill and leak (probabilistic) events, as well as planned discharge of treated wastewater into streams or spreading of brines on roadways.

The delineation of these pathways identifies an array of immediate research priorities. The potential relationships identified in the conceptual model (Figure 5) provide a framework of empirical relationships between Marcellus Shale drilling activities, deterministic pathways, and brook trout populations that need to be tested and verified. There is currently variation in hydraulic fracturing density within the Marcellus Shale, ranging from extensive operations in Pennsylvania and West Virginia to a moratorium on the process in New York. Opportunities exist for researchers to develop studies that verify potential relationships between drilling activities and brook trout populations, such as examining sediment impacts and brook trout responses across watersheds representing a range of well densities (Entrekin et al. 2011) or over time in watersheds with increasing levels of drilling activity. Correlative studies should also be confirmed through experimental approaches that take advantage of paired watershed or before–after control-impact (Downes et al. 2002) designs. Tiered spatial analysis techniques can be used to assess the cumulative impacts of persistent drilling activity within nested drainage areas at a range of spatial scales (Bolstad and Swank 1997; MacDonald 2000; Strager et al. 2009). Additionally, risk assessment analyses based on biological endpoints are needed to characterize impacts of probabilistic events such as chemical spills and leaks (USEPA 1998; Karr and Chu 1997).

MOVING FROM RESEARCH TO MANAGEMENT AND CONSERVATION POLICY

Management of hydraulic fracturing activities in the Marcellus Shale is the responsibility of various permitting regulatory agencies with various scales of influence, including statewide (departments of environmental conservation/protection, departments of transportation, fish and game commissions, etc.) and regional (conservation districts, river basin commissions, etc.) entities. Though the individual policies are too numerous to describe in depth here, it is apparent that policies can be developed and refined with the support of research and monitoring programs that provide crucial data, such as a geographically finer scale understanding of brook trout distribution and population status, seasonal flow requirements for brook trout at their various life stages (Figure 6), identification and prioritization of high-quality habitat, and verification of the potential drilling impacts within the Marcellus Shale. These types of data are necessary for revising existing policies and developing new policies that are protective of brook trout populations and the stream ecosystems that support them in the face of increased Marcellus Shale drilling activities.

An example of science influencing policy that is protective of brook trout habitat is the current and proposed water withdrawal policies for the Susquehanna River Basin. The SRBC governs water withdrawal permitting for the Susquehanna River Basin region, and its policies have the potential to influence the degree to which hydrologic impacts of Marcellus Shale drilling may influence brook trout populations (SRBC 2002). The SRBC currently enforces minimum flow criteria for water withdrawals for hydraulic fracturing in coldwater trout streams to prevent low-flow impacts (Rahm and Riha 2012). The SRBC requires that water withdrawals must stop when stream flow at withdrawal sites falls below predetermined passby flows and cease until acceptable flow returns for 48 h. For small streams (<100 mile^2), passby flows are determined based on instream flow models (Denslinger et al. 1998) and are designed to prevent more than 5% to 15% change in trout habitat, depending on the amount of trout biomass the stream supports. A more general 25% average daily flow requirement is used as the passby flow for larger coldwater trout streams (SRBC 2002). This policy is expected to prevent water withdrawals from impacting habitats during low flows in summer. However, analyses of hypothetical withdrawals within the range of proposed water withdrawal permits suggest that water needs associated with Marcellus Shale drilling will impact seasonal flow needs (not just summer low flow) of small streams likely to support brook trout (DePhilip and Moberg 2010; Rahm and Riha 2012). Additionally, multiple upstream withdrawal events occurring on the same day within the same catchment may culminate in stream flows falling below the passby flow requirement. Though there is considerable uncertainty around water withdrawal estimates, accounting for cumulative withdrawal-induced low-flow effects can increase the number of days that are expected to fall below passby requirements for smaller streams by as much as approximately 100 days within an average year (Rahm and Riha 2012). Consequently, the SRBC has released new proposed low-flow protection regulations for public comment (SRBC 2012b, 2012c), based primarily on recommendations from a cooperative project between The Nature Conservancy, staff from the SRBC, and its member jurisdictions (DePhillip and Moberg 2010). The proposed SRBC flow policy uses a tiered approach to flow protection that prevents withdrawals or puts more stringent requirements in extremely sensitive or exceptional quality streams such as small headwater streams that support reproducing brook trout populations (SRBC 2012b, 2012c). This proposed policy would also provide significant flow protection for trout streams by incorporating seasonal or monthly flow variability into passby flow criteria rather than based on a single average daily flow criterion (Richter et al. 2011; Figure 6) and assessing proposed withdrawal impacts within the context of cumulative flow reductions associated with existing upstream withdrawals (Rahm and Riha 2012). However, the SRBC's proposed policy has received considerable critique from stakeholders, including the natural gas industry (SRBC 2012a). It is unclear what protections a revised water withdrawal policy will provide to streams that support brook trout habitat.

The SRBC policy is only one example of a regulatory body using scientific data to improve and refine a management policy that directly relates to potential drilling impacts on trout populations. It is crucial that policies governing hydraulic fracturing activities be likewise dynamic and subject to adaptation based on updated scientific knowledge. For example, the Pennsylvania *Oil and Gas Operators Manual* provides technical guidance for infrastructure development by identifying best management practices for sediment and erosion control and well pad, road, pipeline, and stream-crossing designs and delineates preventative waste-handling procedures to avoid unexpected probabilistic events like spills and runoff (PADEP 2001). These practices should be amended and updated as new studies refine methods to minimize impacts (e.g., Reid et al. 2004) and strategically protect or restore habitat quality or connectivity (e.g., Poplar-Jeffers et al. 2009). Furthermore, water quality data from monitoring efforts, like TU's Coldwater Conservation Corps (one of many stream survey programs that train and equip volunteers to conduct water quality testing in local streams; TU 2012) can alert regulatory agencies to failures in the probabilistic event prevention strategies that may help better characterize risks and improve waste transport and disposal procedures. For expansion of drilling in new areas, such as into New York State, regulatory agencies including the New York State Department of Environmental Conservation (NYSDEC), which is currently evaluating potential impacts of hydrologic fracturing activities and developing a corresponding set of proposed regulations (NYSDEC 2011), should utilize the most up-to-date and complete scientific data possible from active monitoring efforts to develop best management practices that are optimally protective of natural flow regimes, habitat conditions, and water quality in high-quality streams.

Spatial analysis and visualization of well density (Figure 4) can be combined with refined understanding of brook trout habitat and population status from stream surveys and ground-truthing to prioritize and geographically focus conservation efforts. Currently the Pennsylvania Fish and Boat Commission's Unassessed Waters Program in conjunction with Trout Unlimited and other partner organizations is conducting intensive assessments of streams with unknown brook trout status: to date, this program has identified an additional 99 streams that support wild populations (Weisberg 2011). Similar efforts are being spearheaded in New York by the NYSDEC and TU (2011). Furthermore, the efficacy of regulatory policy can be bolstered by data from monitoring and research efforts that define highest priority watersheds for conservation of brook trout. Various trout-focused organizations have identified key watersheds for protection and restoration. Trout Unlimited has updated their existing Conservation Success Index (J. E. Williams et al. 2007) with a targeted analysis for Pennsylvania to integrate new data on brook trout streams and natural gas drilling threats (TU 2011b). Likewise, the EBTJV has identified an extensive set of action strategies that identify priorities on a state-by-state basis (EBTJV 2011). Results from these types of analyses can be used to identify and direct conservation efforts to key areas where Marcellus Shale drilling activities are likely to have the greatest impacts by disturbing habitat for the highest quality remaining brook trout populations.

In summary, expedient efforts to develop strategies that minimize negative impacts of Marcellus Shale drilling activities on brook trout habitat are needed. Horizontal drilling and hydraulic fracturing for natural gas extraction is likely to increase and expand from Pennsylvania and West Virginia into unexploited areas with growing pressure related to economic incentives from the oil and gas industry and the need for cheap domestic energy sources. Natural gas drilling is expected to persist in the region for several decades due to the extent of the Marcellus Shale natural gas resource and the presence of the gas-rich Utica Shale below it (P. Williams 2008). Consequently, development of adequate management and conservation strategies based on science and enforcement of policies that conserve and protect stream ecosystems supporting brook trout populations and other aquatic organisms are needed to balance energy needs and economic incentives with environmental and brook trout conservation concerns.

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Adaptive Forgetting: Why Predator Recognition Training Might Not Enhance Poststocking Survival

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ABSTRACT: *The success of current fish restocking efforts is often hampered by poor poststocking survival of hatchery-reared juveniles. As a result of hatchery selection, combined with a lack of ecologically relevant experience, hatchery-reared fishes often fail to recognize and respond to potential predators following stocking into natural waterways. One commonly proposed method to enhance potential poststocking survival is to condition hatchery-reared fishes to recognize predators prior to stocking. However, despite a wealth of laboratory and field studies demonstrating predator recognition learning in fishes, only a handful of studies have attempted to assess potential poststocking benefits, and these suggest mixed results. Our goal is to highlight possible causes of this apparent contradiction. A survey of the behavioral ecology literature highlights the exceptional degree of sophistication of predator recognition learning among prey fishes. Moreover, an emerging body of literature suggests that how long prey retain learned predator recognition is as important as what prey learn. This highly plastic retention (memory window) may confer adaptive benefits under variable conditions. Hatchery selection may result in phenotypes leading to reduced learning and/or retention of learned information. We conclude by proposing several avenues of investigation aimed at improving the success of prestocking conditioning paradigms.*

Olvido adaptativo: por qué el entrenamiento para reconocer depredadores puede no incrementar la supervivencia después del repoblamiento

RESUMEN: El éxito de los esfuerzos de repoblamiento de peces suele disminuir debido a condiciones desfavorables para la supervivencia de juveniles, provenientes de cultivo, tras prácticas de repoblamiento. Como resultado de la selección en cultivo, en combinación con la falta de experiencia en temas de ecología, los peces de cultivo a veces fallan en reconocer y responder potenciales depredadores después de haber sido introducidos, con fines de repoblamiento, a cuerpos de agua. Un método comúnmente propuesto para aumentar la supervivencia post-repoblamiento es condicionar a los juveniles de peces cultivados a que reconozcan a sus depredadores antes de la translocación. Sin embargo, pese al buen equipamiento de los laboratorios y a los trabajos en campo que demuestran la capacidad de aprendizaje de los peces para reconocer depredadores, solo unos pocos estudios se han enfocado en evaluar los beneficios potenciales post-repoblamiento y dichos estudios muestran resultados encontrados. Nuestro objetivo es subrayar las posibles causas de esta aparente contradicción. Un sondeo bibliográfico acerca de ecología conductual destaca la extraordinaria sofisticación del proceso de aprendizaje en peces para reconocer a sus depredadores. No obstante, otra parte de la literatura reciente sugiere que el tiempo que los peces retienen el patrón de reconocimiento del depredador es igualmente importante que lo aprendido por el individuo. Esta retención altamente flexible (ventana de memoria) puede conferir beneficios adaptativos ante condiciones variables. La selección mediante el cultivo puede resultar en fenotipos caracterizados por una reducida capacidad y/o poca retención de la información aprendida. Concluimos proponiendo distintas líneas de investigación cuyo propósito es aumentar el éxito del acondicionamiento previo al repoblamiento.

Hatchery-reared (HR) fishes, especially salmonids, are routinely stocked into natural waterways as part of population enhancement, recovery programs, and conservation efforts (C. Brown and Laland 2001; Salvanes and Braithwaite 2006; Fraser 2008). These recovery programs, however, are often met with limited success. Though some studies have shown that HR fish have similar poststocking survival rates as do their wild counterparts (e.g., Johnson et al. 2010), many studies point toward reduced survival among HR populations (e.g., Olla et al. 1994; Shively et al. 1996; Salvanes and Braithwaite 2006). A reduced survival may be due, in part, to the maladaptive behavioral phenotypes of HR fish, compared to their wild counterparts (C. Brown and Day 2002; Fraser 2008; Fernö et al. 2011). A growing body of research shows that hatchery-rearing, even over a little as one to two generations, is sufficient to induce significant differences in foraging (Fernö et al. 2011), growth rates (Tymchuck et al. 2007), risk-taking behavioral tactics (Sundström et al. 2004), and predator avoidance behaviors (Shively et al. 1996; Houde et al. 2010; Jackson and Brown 2011) between HR salmonids and their wild counterparts. Such differences in behavioral phenotypes may lead to stocked fish having reduced growth rates, increased predation risk, and/or reduced fitness (Huntingford 2004; Fernö et al. 2011).

Maladaptive behavioral phenotypes may arise from one of two possible mechanisms or, more likely, a combination of the two. Initially, under hatchery conditions, juvenile HR fishes lack experience with natural foraging conditions, microhabitat variability, and predation threats (Olla et al. 1998; C. Brown and Day 2002; Fernö et al. 2011). As a result of the unnatural hatchery environment, juvenile HR fishes might suffer from a lack of opportunity to learn through direct or indirect experience (Fernö et al. 2011), resulting in poorly developed or context-inappropriate behavioral phenotypes (C. Brown and Day 2002). Secondly, behavioral differences between hatchery and wild populations may be the result of genetic divergence resulting from either inadvertent selection for traits that are beneficial under hatchery conditions or the relaxation of natural selection pressures under hatchery conditions (Huntingford 2004; Fraser 2008). Jackson and Brown (2011) directly tested this hypothesis under natural conditions with juvenile Atlantic salmon (Salmo salar) originating from the same population. They compared the predator avoidance behavior of wild-caught juvenile Atlantic salmon with that of the offspring of wild-caught parents (F_1) and the offspring of parents that had spent one full generation under hatchery conditions (F_2). Jackson and Brown (2011) found the strongest predator avoidance response to a standardized predation cue among wild-caught salmon and the weakest response among F_2 salmon. Curiously, the response of the F_1 group was intermediate, suggesting that both hatchery selection and a lack of ecologically relevant experience contribute to the maladaptive behavior patterns among HR salmon.

A commonly advocated solution in a wide range of taxonomically diverse prey populations reared under artificial conditions is "life skills training" (Suboski and Templeton 1989; G. E. Brown and Smith 1998; C. Brown and Laland 2001). The idea that HR fish can be taught to recognize potential predators prior to stocking is attractive because it could allow for increased poststocking survival. Such enhanced survival would reduce the costs associated with stocking programs and potentially increase the effectiveness of population recovery efforts (Salvanes and Braithwaite 2006). However, despite considerable effort to demonstrate learning under laboratory conditions (reviewed in G. E. Brown et al. 2011a), only a few studies have attempted to demonstrate the potential benefits of prestocking predator recognition training efforts on the poststocking survival of commercially important species. These studies have provided, at best, mixed results. For example, Berejikian et al. (1999) found that though Chinook salmon (*Oncorhynchus tshawytscha*) could be conditioned to avoid the odor of an ecologically relevant predator (adult cutthroat trout, *Oncorhynchus clarki*) under laboratory conditions, this did not result in enhanced poststocking survival. Likewise, Hawkins et al. (2007) conditioned 1+ Atlantic salmon (*Salmo salar*) to recognize northern pike (*Esox lucius*) as a potential predator. Conditioned salmon survived no better when stocked into lakes where pike were the dominant predator. Conversely, D'Anna et al. (2012) conditioned white seabream (*Diplodus sargus*) prior to release and found a near doubling of poststocking survival. Likewise, Hutchinson et al. (2012) demonstrated two- to fourfold increases in poststocking survival of juvenile Murray cod (*Maccullochella peelii*) but not for juvenile silver perch (*Bidyanus bidyanus*). Thus, we are left with the question of why this type of learning may not translate to enhanced survival.

Here, we provide an overview of recent work examining chemically mediated predator recognition mechanisms in aquatic prey species and highlight the incredible degree of sophistication involved in these learning mechanisms. In addition, we examine the poorly understood aspect of retention of learned information. Finally, we conclude with some potential avenues to address the question of why prestocking training might not work to increase poststocking survival. The extent to which hatchery effects (selection + differential experience) will impact the poststocking survival and learning ability of fishes clearly depends upon the holding and breeding practices employed within hatcheries. For example, Beckman et al. (1999) found that differences in prestocking growth rate of hatchery-reared Chinook salmon was related to the likelihood of stocked smolts returning as adults. Likewise, habitat enrichment within hatchery-rearing tanks is known to enhance natural foraging patterns, possibly increasing poststocking survival (Roberts et al. 2011). For simplicity, we refer to the dichotomy of hatchery-reared vs. wild-stock fishes within the context of predator-recognition learning. Our goal here is to bring to light recent advances in the study of ecologically relevant learning mechanisms and to bridge the gap between the behavioral ecological literature and possible fisheries applications.

THE SOPHISTICATION OF PREDATOR RECOGNITION LEARNING IN FISHES

Learning, in the broadest sense, can be defined as the ability to modify behavioral response patterns based on experience (G. E. Brown and Chivers 2005). The ability to reliably assess local predation threats allows prey (including juvenile salmonids) to balance the often conflicting demands of predator avoidance and a suite of behavioral activities such as foraging and territorial defense (Lima and Dill 1990; Kim et al. 2011). This is especially difficult under conditions of variable predation risk and/or foraging opportunity (Sih 1992; Dall et al. 2005). Learning to recognize potential predators allows prey to respond only to ecologically relevant threats and to avoid expending time and energy responding to irrelevant cues. In addition, learned recognition has been shown to increase survival during staged encounters with live predators (Mirza and Chivers 2000; Darwish et al. 2005; Vilhunen 2006). Thus, under conditions of variable predation risks, learning is argued to allow prey to optimize the trade-off between predator avoidance and other fitness-related activities (G. E. Brown and Chivers 2005; Dall et al. 2005; G. E. Brown et al. 2011a).

A large body of research has investigated the mechanisms of predator recognition learning in fishes (Ferrari et al. 2010a; G. E. Brown et al. 2011c). A well-documented mechanism of learning is the so-called chemically mediated learning. Damage-released chemical alarm cues are a common feature in freshwater and marine fishes (Ferrari et al. 2010c), which are released following mechanical damage incurred during an attack by a predator. Given the mechanism of release, these chemosensory cues are reliable indicators of predation threats (Chivers et al. 2007, 2012; Ferrari et al. 2010c). When released into the water column and detected by nearby conspecifics and/or heterospecifics, these cues may elicit dramatic, short-term increases in species-specific antipredator behavior (Ferrari et al. 2010c). Recent studies demonstrate that alarm cues convey a surprising amount of information regarding local predation threats. For example, the response intensity of many prey fishes appears to be proportional to the concentration of alarm cue detected (e.g., Dupuch et al. 2004; G. E. Brown et al. 2006, 2009). Similarly, detecting alarm cues at concentrations below that needed to elicit an observable antipredator response are known to increase the use of secondary cues (i.e., visual information; G. E. Brown et al. 2004).

When paired with the visual and/or chemical cues of a novel predator, these alarm cues can facilitate the learned recognition of a novel predator (G. E. Brown et al. 2011a). For example, when juvenile rainbow trout are presented with the paired stimuli of a conspecific alarm cue (innate unconditioned stimulus) and the odor of a novel predator (conditioned stimulus), the trout will exhibit a strong increase in predator avoidance toward the alarm cue. However, when later presented with the predator odor, the trout will increase predator avoidance, demonstrating a learned response to the previously novel predator cue (G. E. Brown and Smith 1998). Following a single conditioning trial, these learned responses may persist for several weeks (G. E. Brown and Smith 1998). Control trials, in which the predator odor is paired with distilled water, fail to elicit any evidence of learning (G. E. Brown and Smith 1998).

A wealth of studies has demonstrated that this type of direct learning is common among aquatic prey species (reviewed in G. E. Brown et al. 2011a). Recent studies have shown that juvenile Atlantic salmon are capable of such chemically mediated learning under fully natural conditions (Leduc et al. 2007). More impressive, however, is the exceptional degree of sophistication present in this learning system. For example, fathead minnows (*Pimephales promelas*) are capable of learning threat-sensitive responses (i.e., the intensity of the behavioral response is directly proportional to the level of risk; G. E. Brown et al. 2006) via this mechanism. When paired with a low concentration of alarm cue (hence low risk), prey will exhibit a similarly low-intensity response to pike odor. However, when the pike odor is paired with a high concentration of alarm cue (hence high risk), the minnows learn to exhibit a high-intensity response (Ferrari et al. 2005). Recent experiments with HR rainbow trout extend these findings, showing that when conditioned to recognize pumpkinseed (*Lepomis gibbosus*) as predation threats, trout can generalize the learned response to the odors of predators that are taxonomically related to pumpkinseed (i.e., longear sunfish, *Lepomis megalotis*) but not to those of more distantly related predators (i.e., yellow perch, *Perca flavescens*; Brown et al. 2011c). Finally, when glowlight tetras (*Hemigrammus erythrozonus*) are conditioned with a conspecific alarm cue paired with the combined odor of largemouth bass (*Micropterus salmoides*), convict cichlids (*Amatitlania nigrofasciata*), and common goldfish (*Carassius auratus*), they are capable of exhibiting increased antipredator behavior in response to individual predator odors but not the odor of a predator not included in the cocktail (yellow perch; Darwish et al. 2005). Moreover, this cocktail learning was shown to increase survival during staged encounters with live predators (Darwish et al. 2005).

Learned predator recognition may also occur via indirect learning mechanisms. Initially, predator recognition can be facilitated via the mechanism of social or observational learning. Social learning may occur when prey acquire the recognition of novel predator cues in the absence of any direct experience (Mathis et al. 1996); simply observing an experienced conspecific (or heterospecific) prey respond to a predator cue can provide sufficient information to allow learning to occur. Such social learning may allow for the rapid transmission of recognition of novel predator cues within populations (G. E. Brown et al. 1997) and has been employed under hatchery conditions to enhance the learning of context-appropriate foraging patterns (C. Brown et al. 2003; Rodewald et al. 2011). Secondly, predator diet cues may also facilitate learning. For example, fathead minnows exposed to northern pike fed a diet of minnows learn to recognize the visual cues of pike (i.e., will respond to the sight of the predator), whereas minnows exposed to pike fed an unknown diet do not respond to the sight of the pike (Mathis and Smith 1993). Likewise, the response of juvenile Arctic charr (*Salvelinus alpinus*) to predator odors is enhanced when the predators have been fed charr versus when they are food deprived (Vilhunen and Hirvonen 2003). Finally, age of individuals seems to influence their ability to learn novel predator recognition. For example, Hawkins et al. (2008) demonstrated that juvenile Atlantic salmon exhibit age-specific sensitivity to novel predator odors. Under laboratory conditions, 10- to 15-week posthatching salmon were more responsive to pike odor than were younger or older conspecifics. Moreover, 16- to 20-week posthatching salmon were better able to learn to recognize novel predator odors than were younger salmon. Hutchison et al. (2012), however, found that whereas Murray cod fingerlings can learn to recognize novel predators, subadults exhibited no evidence of learning. Combined, these findings suggest a critical ontogenetic constraint on the timing of predator recognition learning.

Together, these studies demonstrate that chemically mediated predator recognition learning is a highly sophisticated and complex mechanism allowing for an incredible degree of behavioral plasticity. Under conditions of uncertain predation threats, the ability to modify predator avoidance responses based on recent experience likely confers significant fitness advantages (Dall et al. 2005; G. E. Brown et al. 2011a). However, if learning is so critical to the survival of wild prey populations, why should prestocking conditioning not confer increased survival benefits? The answer to this question might lie in the emerging question of retention of learned information (i.e., memory).

RETENTION OF LEARNED INFORMATION

Though there is a very large body of literature demonstrating the learning abilities and ecological constraints on learning in prey organisms (reviewed in G. E. Brown and Chivers 2005; G. E. Brown et al. 2011a), surprisingly little is known about the retention of learned information. The retention of learned predator recognition varies widely among prey fishes (Ferrari et al. 2010a). For example, following a single conditioning event, HR rainbow trout conditioned to recognize a novel predator will retain a detectable response for up to 21 days (G. E. Brown and Smith 1998), though the intensity of the response wanes after approximately 10 days (Mirza and Chivers 2000). Conversely, after a single conditioning, fathead minnows retained their learned response to a novel predator cue for at least 2 months with little evidence of a decrease in response intensity (Chivers and Smith 1994). Similar studies have shown that learned foraging preferences also vary within and between populations (Mackney and Hughes 1995).

Recently, Ferrari et al. (2010a) proposed a model of "adaptive forgetting," suggesting that the retention (how long prey will exhibit an observable response) to learned information is flexible and dependent on the certainty of this information. Under natural conditions, prey must balance the need to detect and avoid predation threats and to maximize foraging and reproduction (Lima and Dill 1990). The ability to balance these trade-offs depends on the availability of accurate and reliable information regarding risk associated with potential predators (Dall et al. 2005). In turn, the reliability of learned information should impact the duration of its retention (Ferrari et al. 2010a). For example, prey may outgrow gape limits of potential predators, reducing the value of learned recognition. Exhibiting an increased predator avoidance response toward this previously learned cue would represent a cost in the form of lost energy intake. However, if the prey were still at risk to the predator, failure to respond might result in death.

Ferrari et al. (2010a) suggested a number of intrinsic (i.e., prey growth rate, behavioral tactics) and extrinsic (i.e., predictability of predation threats, predator risk level) factors that would be expected to influence the retention of learned information. This model is particularly relevant to the issue of prestocking predator recognition training because hatchery selection may influence the very factors that shape the retention of learned information. Next, we will discuss several relevant examples from our recent work.

RETENTION AND THE EFFECTS OF HATCHERY SELECTION

Personality and Retention

A growing body of literature demonstrates consistent behavioral tactics, often referred to as "shy" vs. "bold" phenotypes, in a wide range of fishes (including salmonids; Budaev and Brown 2011). Generally speaking, individuals with bold phenotypes are more likely to continue foraging under the risk of predation, return to foraging sooner following an attack from a predator, and spend more time away from shelter compared to shy conspecifics (Budaev and Brown 2011). According to the framework of adaptive forgetting (Ferrari et al. 2010a), we might expect bold individuals to retain learned predator recognition less effectively than shy conspecifics due to the reduced value placed on predator avoidance (Tymchuk et al. 2007). This is relevant to the prestocking paradigm, because hatchery-reared fish generally exhibit bolder behavioral tactics (i.e., brown trout, *Salmo trutta*; Sundström et al. 2004) and attenuated stress responses than do wild-caught conspecifics (Lepage et al. 2000), leading to potentially maladaptive behavior patterns.

Recently, we directly tested this prediction with HR juvenile rainbow trout. Juvenile trout were classified as shy vs. bold based on their latency to escape from an opaque chamber into a large test arena (a reliable method of assessing behavioral tactics; C. Brown et al. 2005; Wilson and McLaughlin 2007) and conditioned to recognize a novel predator cue (pumpkinseed odor). When tested for recognition of the conditioned cue 24 h later, there was no difference in the intensity of the learned antipredator response (Figure 1). However, when tested 9 days postconditioning, we found that bold trout no longer exhibited any evidence of retention of the learned response. Shy trout exhibited strong responses, similar to those of the day 2 testing (Figure 1). These data suggest that though it is possible to condition HR fish to recognize predators, they simply may not retain the information long enough to gain a functional benefit due to their bold behavioral phenotypes (G. E. Brown et al. in press).

Growth Rates and Retention

Another common trait within hatchery settings is increased growth rates associated with both the reliable availability of food and the relaxation of competitive pressures (C. Brown and Laland 2002; Saikkonen et al. 2011). Ferrari et al. (2010a) suggested that increased growth rates should reduce the rela-

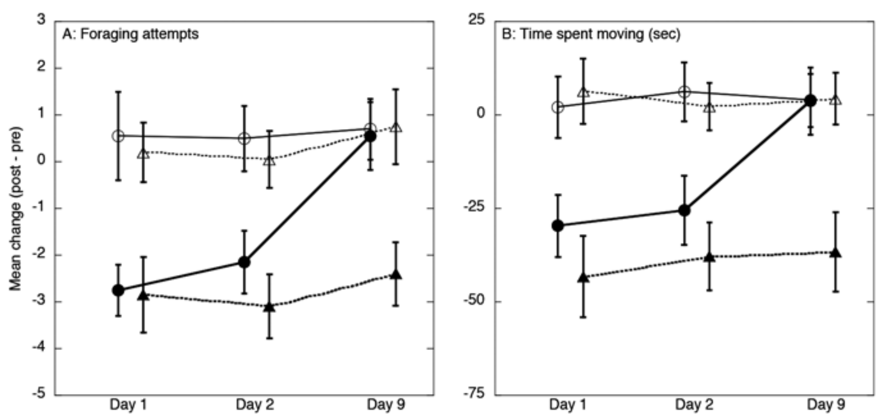

Figure 1. Mean (±SE) change in foraging attempts (A) and time moving (B) for shy (solid triangles) vs. bold (solid circles) rainbow trout conditioned to recognize pumpkinseed as a predation threat on day 1 and subsequently tested for recognition of pumpkinseed odor alone on day 2 and day 9. Shy phenotype trout exhibited significantly longer retention when compare to bold phenotype trout. Open symbols represent pseudoconditioned controls. Modified from G. E. Brown et al. (in press).

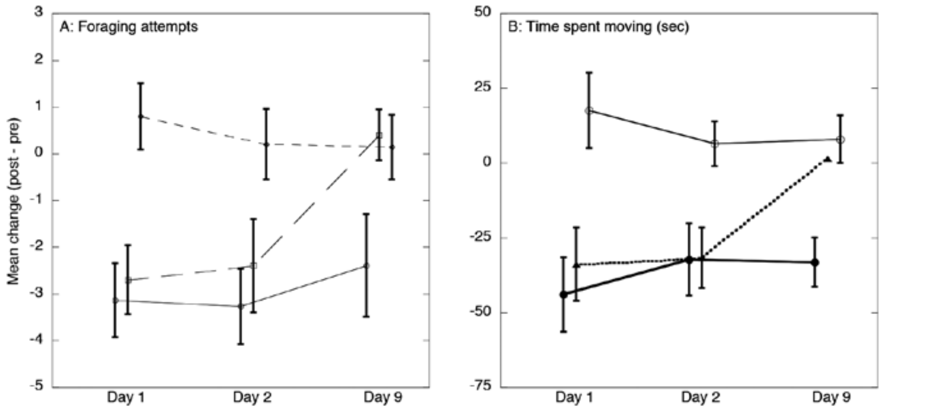

Figure 2. Mean (±SE) change in foraging attempts for juvenile rainbow trout conditioned to recognize pumpkinseed odor as a predation threat (circles) or pseudoconditioned (control; triangles) and subsequently exposed to pumpkinseed odor either 24 h postconditioning (day 2) or 8 days postconditioning (day 9). Panel A depicts results where groups of trout of similar initial mass were fed a high food (5% mbw day−1) or a low food (1% mbw day−1) ration the duration of the study. Panel B depicts results where trout of different initial masses were fed the same food ration (1% mbw day−1). Modified from G. E. Brown et al. (2011c).

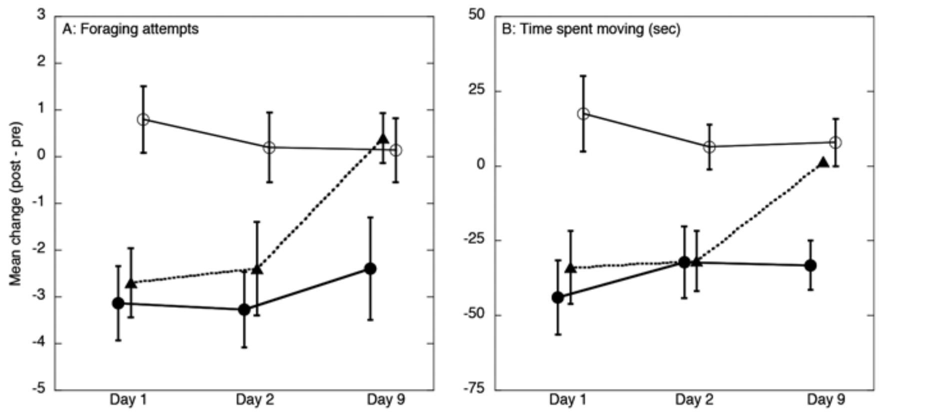

Figure 3. Mean (±SE) change in foraging attempts (A) and time moving (B) for juvenile rainbow trout conditioned with a high risk cue (circles), a low risk cue (triangles) or pseudoconditioned (squares) to recognize pumpkinseed odor as a predator cue. Modified from Ferrari et al. (2010b).

tive value of learned information. G. E. Brown et al. (2011b) tested this hypothesis under laboratory conditions with HR rainbow trout. Juvenile trout, matched for size, were reared on 1% or 5% mbw day^{-1} diets of standard trout chow for 7 days and then conditioned (or pseudoconditioned) to recognize a novel pumpkinseed predator. They were then either tested 24 h postconditioning (day 2) or held on the same 1% or 5% diet for an additional 8 days and then tested for recognition. The results suggest that though there was no difference in the intensity of the learned response between high and low food rations on day 2, only trout reared on the low food ration (low growth rate) showed any evidence of retention when tested on day 9. The observation that response intensity among conditioned trout on day 2 did not differ precludes the possibility that the observed differences on day 9 were due to hunger levels. Trout reared on the high growth rate ration were not different from pseudoconditioned controls (Figure 2A). These results were further supported by a companion study in which small (~0.6 g) and larger (~1.8 g) trout were fed the same 1% mbw day^{-1} rations and tested as above (Brown et al. 2011b). Despite a threefold difference in size, retention was similar between small and large trout (Figure 2B). Combined, these results demonstrate that growth rate at the time of conditioning influences the value of the learned information, leading to differential retention times.

Strength of Initial Conditioning

Several authors have shown that the strength of the initial conditioning event influences the overall intensity of learned predator recognition (Vilhunen and Hirvonen 2003; Ferrari et al. 2005; Zhao et al. 2006). For example, fathead minnows exhibit concentration dependent response intensities to conspecific alarm cues. Ferrari et al. (2005) found that the learned response to novel predator odors matched the intensity of the response during the initial conditioning event. More recently, Ferrari et al. (2010b) found that HR rainbow trout exhibited threat-sensitive retention of learned predator cues. Trout were conditioned to a high or low concentration of conspecific alarm cues (simulating high- vs. low-risk conditions) paired with the odor of pumpkinseeds (or pseudoconditioned) and tested for recognition. When tested for recognition 24 h postconditioning, they found that conditioned trout exhibited learned responses toward the predator cue but the intensity of response did not differ between those conditioned to high vs. low risk cues. However, when tested 8 days postconditioning, those initially exposed to the low risk cue did not retain the learned response (Figure 3).

Ontogenetic Constraints on Learning

Thought it has not been directly tested, it is possible that ontogenetic stage may also play an important role in the retention of learned predator recognition. As mentioned above, Hawkins et al. (2008) and Hutchison et al. (2012) have demonstrated age-specific propensities for chemically mediated learning in juvenile Atlantic salmon and Murray cod. Moreover, as salmonids undergo smoltification, they incur considerable physiological stress (Järvi 1990). This, combined with increased standard metabolic rates in smolts vs. nonsmolting conspecifics (Seppänen et al. 2010), might lead to a reduction in the value of learned predator recognition in favor of increased foraging demands. Several studies (Damsgård and Arnesen 1998; Skilbrei and Hansen 2004) showed a short-term reduction in growth rate and foraging during the smoltification phase but this is typically followed by an extended period of rapid growth. Such a shift in the value of predator avoidance vs. foraging benefits could lead to a reduction in retention (Ferrari et al. 2010a, 2010b).

However, size (ontogeny) has been shown to significantly influence risk-taking tactics in juvenile coho salmon (*Onchorhynchus kisutch*). Reinhardt and Healey (1999) compared the latency to resume foraging (as a measure of antipredator response intensity) among small (~1.5 g) vs. large (~3.5 g) coho salmon reared on similar food rations. Given that maximum potential growth rate is size dependent, larger fish will be capable of realizing a higher percentage of potential growth compared to smaller conspecifics during peak growing seasons (Reinhardt and Healey 1999). Reinhardt and Healey (1999) found that among the small-sized cohort, prior growth rate had a significant positive relationship with the latency to resume foraging following exposure to a standardized predation threat, suggesting that those with lower realized potential growth were more willing to accept increased risk in order to continue foraging in accordance with the asset protection model (Clark 1994). However, they found no effect of prior growth on the risk-taking tactics of the larger cohort. According to Ferrari et al. (2010c), prey that are more willing to accept risk in order to continue foraging (i.e., bold) should show reduced retention periods compared to more risk averse individuals. Thus, potential for growth influencing risk-taking tactics (asset protection) rather than actual growth (G. E. Brown et al. 2011b) may also shape retention.

Photo 1. Behavioral observations of juvenile Atlantic salmon in the Catamaran Brook, New Brunswick. The orange markers (upper left) indicate foraging territories of individual salmon. Photo Credit: G. E. Brown.

Photo 2. Mesh enclosures anchored in the Catamaran Brook, New Brunswick. Enclosures can be stocked with tagged salmon and allow for long-term studies of behavior under natural conditions. Photo Credit: C. K. Elvidge.

Implications for Prestocking Conditioning

Taken together, we see that the mechanism of chemically mediated predator recognition learning is an incredibly complex and sophisticated system, allowing for the acquisition of complex, context-specific behavioral response patterns within a wide variety of aquatic prey species. Moreover, an emerging field of research suggests that the question of how long to retain learned information is just as important to prey species as is the question of what to learn. Clearly, both learning and retention are highly plastic processes, shaped by environmental variability. If predator recognition learning is to result in increased poststocking survival, as suggested by a variety of authors (Suboski and Templeton 1989; C. Brown and Laland 2001; Fernö et al. 2011), we should revisit the design of prestocking conditioning paradigms in light of the results presented above. Next, we suggest a number of possible avenues for future studies. Many of the topics discussed below have previously been considered in the context of hatchery practices with an aim to enhance growth, quality, and survival, as well as the effectiveness of hatchery practices as a conservation tool (i.e., Sharma et al. 2005; Paquet et al. 2011). Thus, we limit our discussion to the relevance toward life skills training. Any findings must be considered in light of current best practices within the hatchery setting.

POSSIBLE AVENUES FOR FUTURE RESEARCH

One possibility to overcome this potential retention issue associated with prestocking conditioning would be to increase the strength of the initial conditioning event. Increasing the number of conditioning events may strengthen the initial learning and hence extend the retention of prestocking conditioning. Vilhunen (2006) found that HR Arctic charr exposed to four sequential conditioning events exhibited stronger learned responses than those conditioned a single time. Moreover, multiple conditioning events enhanced survival during staged encounters with predators. Typically, prestocking training studies have actively conditioned HR salmonids once or twice. It is possible that multiple conditioning events would extend the duration of retention, allowing for increased poststocking benefits. Likewise, based on the findings of Ferrari et al. (2010a), increased concentrations of alarm cues, indicating higher risks, should increase the strength of the initial conditioning. A recent study by Ferrari et al. (2012) demonstrated that woodfrog tadpoles (*Rana sylvatica*) that have been conditioned to recognize a novel predator odor four times retained their learned response longer than those conditioned once. This could combine with the potential benefits of social learning (C. Brown et al. 2003; Vilhunen et al. 2005).

A potential difficulty associated with repeated conditioning might be that HR fish may habituate to the predator odor. Though Vilhunen (2006) found that repeated conditionings enhanced the strength of learning, Berejikian et al. (2003) suggested that HR Chinook salmon may habituate to repeated exposures to the predator odor. There are, however, several differences between these two studies, the most relevant of which include the fact that Berijikian et al. (2003) tested Chinook salmon that were roughly twice the size as the Arctic charr tested by Vilhunen (2006). The observed differences could be related to species-specific differences in learning abilities or ontogenetic effects. Additional work is needed to examine the potential limitations associated with habituation.

A second potential avenue would be to reduce the latency between conditioning and stocking. In-stream or near-shore enclosures could be used to hold stocked fish prior to release. Such enclosures would expose HR salmonids to natural flow and drift regimes and would allow for acclimation prior to release. Large groups could then be conditioned and released. Recent work by Olson et al. (2012) suggested that mass conditioning may allow for the effective prestocking conditioning of HR fishes. Enclosure conditioning could also take advantage of potential social learning (C. Brown et al. 2003; Vilhunen et al. 2005; D'Anna et al. 2012). Vihunen et al. (2005) demonstrated that the effectiveness of social predator recognition learning is greatest when a relatively small number of experienced prey are housed with naïve prey.

Third, as described above, growth rate at the time of conditioning appears to influence retention of acquired predator recognition in at least one HR salmonid. Studies are needed to determine the potential effectiveness of placing HR salmonids on a restricted food ration prior to stocking. For example, HR stocks fed with on-demand feeders could be switched to fixed-ration feeders. Limiting the available foraging opportunities for a short time frame (a few days) may have an impact on retention without increasing stress or competition among stock populations (Ashley 2007).

Fourth, a limited number of studies examining the potential benefits of prestocking conditioning on postrelease survival have been conducted on smolts. Additional studies focused on presmolt life history stages are needed. Though it is clear that under laboratory conditions, smolts can indeed acquire recognition of novel predators (i.e., Berejikian et al. 1999), the increased physiological stress associated with smoltification and migration (Järvi 1990) may function to reduce the value of learned information. It is possible that young-of-the-year fry would exhibit longer retention periods, allowing for potential poststocking survival benefits.

Fifth, as mentioned earlier, HR fish may exhibit maladaptive or poorly developed foraging behavior in addition to impaired predator recognition. Several authors (i.e., Brown and Laland 2002; Rodewald et al. 2011) have successfully employed social learning and/or environmental enrichment to encourage context-appropriate foraging behavior in HR fishes prior to stocking. Under natural conditions, prey must balance the need to forage and avoid predators (Lima and Dill 1990). As such, there is a strong interaction between the two suites of behaviors. Combining context-appropriate foraging and predator recognition into an overall life skills training approach (C. Brown and Laland 2001) may further enhance the poststocking survival of HR fishes. In addition, as described above, prey can be conditioned to recognize multiple predators simultaneously (i.e., Darwish et al. 2005) and can generalize learned recognition across predators (i.e., G. E. Brown et al. 2011c). Learning multiple predators' cues at the same time or generalizing across ecologically relevant predators would further increase the ability of HR fishes to balance foraging—predator-avoidance tradeoffs—and may enhance poststocking survival.

The final issue that needs careful consideration is the habitat characteristics of both the conditioning environment and the place where the fish are to be released. Interactions between habitat characteristic and learning are at their infancy, but there are a few noteworthy studies that should provide us with issues to consider. For example, Gazdewich and Chivers (2002) conditioned minnows to recognize yellow perch as a predator and then staged encounters in two different habitat types. There was a clear effect of the predator training on prey survival, but this was only evident when the encounters were staged in one habitat type. Considering the pre- and postconditioning environment may be crucial for the success of training programs. In another study, Smith et al. (2008) conditioned rainbow trout to recognize a novel predator odor at either pH 6.0 or 7.0. A week later, the fish that were tested for recognition of the odor at the pH used during conditioning displayed antipredator responses, whereas those tested at the other pH did not. This study points to the need to consider the water quality parameters of the water body in which the fish are released. A simple change in pH may render learning ineffective and the training programs a waste of valuable resources.

Taken together, the research described in our review suggests that more research is needed to investigate the potential benefits associated with prestocking predator recognition training. The behavioral ecology literature suggests that learning is an adaptive phenotype that confers significant benefits under conditions of variable predation risk. Moreover, this literature suggests that the question of how long learned information is retained is equally as important as what information is learned.

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W.F. Thompson Award for Best Student Paper Published in 2011

Nominations are open for the W.F. Thompson Award, which will be given by the American Institute of Fishery Research Biologists (AIFRB) to recognize the best student paper in fisheries science published during 2011. The award will consist of a check for $1000, a certificate, and a one-year membership in AIFRB at an appropriate level. The requirements for eligibility are as follows:

(1) the paper must be based on research performed while the student was a candidate for a Bachelor's, Master's, or Ph.D degree at a college or university in the Western Hemisphere;

(2) the results of the research must have been submitted to the recognized scientific journal in which it was eventually published, or to the editor of the book in which it was eventually published, within three (3) years of termination of student status;

(3) papers that are considered for the award must be concerned with freshwater or marine biological resources;

(4) the paper must be in English; and

(5) the student must be the senior author of the paper.

Nominations may be submitted by professors or other mentors, associates of the students, or by the students themselves.

The deadline for receipt of nominations is January 31, 2013. The nominations should be sent to the Chairman of the W.F. Thompson Award Committee, Dr. Frank M. Panek, USGS-Leetown Science Center, 11649 Leetown Rd, Kearneysville, WV 25430 (email: fpanek@usgs.gov).

Each nomination must be accompanied by a copy of the paper (unless it is easily available on the internet) and a résumé.

The papers will be judged by knowledgeable subject matter reviewers selected by the Chairman and members of the Committee on the basis of contribution to fisheries science, originality, and presentation.

The National Ecological Observatory Network: An Observatory Poised to Expand Spatiotemporal Scales of Inquiry in Aquatic and Fisheries Science

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ABSTRACT: *Large spatiotemporal-scale fisheries research amid pervasive environmental change requires scientific resources beyond the capabilities of individual laboratories. Here we introduce the aquatics program within a novel institution, the National Ecological Observatory Network (NEON), poised to substantially advance spatiotemporal scales of inquiry in fisheries research. NEON will collect high-quality data from sites distributed throughout the United States, including Alaska, Hawaii, and Puerto Rico, for 30 years. Data products will include hundreds of metrics that comprehensively quantify the biological, chemical, and hydrogeomorphic attributes of streams, lakes, and rivers in the observatory network. Coupling observations from NEON terrestrial, atmospheric, and airborne programs will facilitate unique inquiries in ecohydrology. All NEON-generated data will be rigorously quality controlled and posted to an entirely open-access web portal. Proposals that expand the observatory scope through additional observations, sites, or experiments are encouraged. Thus, NEON represents an unprecedented and dynamic resource for fisheries researchers in the coming decades.*

La red del Observatorio Ecológico Nacional: un sistema listo para expandir la escala espacio-temporal de la investigación en la ciencia acuática y pesquera

RESUMEN: La investigación pesquera en grandes escalas espacio-temporales, dentro de un ambiente cambiante, requiere de recursos científicos que van más allá de las capacidades de laboratorios individuales. En la presente contribución se introduce el programa "aquatics" concebido en el seno de una institución de reciente formación, el Observatorio Ecológico Nacional (NEON) que fue diseñado para mejorar de forma sustancial la escala de investigación espacio-temporal de las ciencias pesqueras. NEON recolectará datos de alta calidad, dentro de un periodo de 30 años, de distintos sitios distribuidos a lo largo de los Estados Unidos de Norteamérica, incluyendo Alaska, Hawái y Puerto Rico. Los datos incluirán cientos de medidas que cuantifican los atributos biológicos, químicos e hidrogeomorfológicos de arroyos, lagos y ríos que abarca el observatorio. El acoplamiento de observaciones de los programas terrestres, atmosféricos y aéreos de NEON facilitará la investigación eco-hidrológica. Todos los datos generados por NEON pasarán por un riguroso control de calidad y serán puestos a disposición del público en general en un portal de internet. Se exhortan aquellas propuestas que, a través de la adición de observaciones, sitios o experimentos, estén encaminadas a expandir el ámbito del observatorio. Así, NEON representa un recurso, dinámico y sin precedentes, para los investigadores pesqueros en las próximas décadas.

INTRODUCTION

Understanding the multiscaled spatial and temporal processes that structure aquatic ecosystems is a fundamental challenge in fisheries management and conservation. For example, the suite of physical controls that shape habitat templates in rivers operate with observable signatures spanning approximately 15 orders of magnitude across time and space (Minshall 1988), whereas processes occurring among and within interacting populations of organisms exhibit an arguably equivalent degree of spatiotemporal heterogeneity (Fausch et al. 2002). Complicating matters further, freshwater and terrestrial ecosystems are inexorably linked through nutrient (Marcarelli et al. 2011), prey (Wipfli and Baxter 2010), and water subsidies also operating at variable spatiotemporal scales. Finite resources inevitably limit the spatial and temporal extent of virtually all ecological studies, resulting in a high likelihood of overlooking or mischaracterizing important patterns and processes (Cooper et al. 1998). Such knowledge gaps inevitably lead to uncertainties when developing science-informed management decisions.

Applying broad-scale spatiotemporal data often proves to be an effective means of addressing such challenges. For instance, long-term data sets from widely distributed locations have been recently used to highlight greater than expected phenological responses of plants to climate change (Wolkovich et al. 2012), demonstrate spatially pervasive trends of rising water temperatures in streams and rivers (Kaushal et al. 2010), and evaluate the current status of marine fisheries on a global spatial scale (Worm et al. 2009). Yet the information resources that led to such findings represent the exception in ecology, with the majority of collected data within the field remaining proprietary and inaccessible despite the clear need for openness in such a collaborative, interdisciplinary science (Reichman et al. 2011). Furthermore, even when data are freely available, poorly documented metadata, incomplete provenance, and/or inconsistent methodology can render comparability among locations or across time spans impossible (Peters 2010).

Fortunately, several recently initiated large-scale environmental observatories will soon expand scales of inquiry in disciplines with ties to fisheries science for all researchers. Such networks aim to freely provide multidecadal data records collected using standardized methodology to allow trend comparisons among widely dispersed sites. For instance, the National Science Foundation (NSF)-supported Ocean Observatory Initiative will begin publishing 25 years worth of open-access multivariate oceanographic data from a network of deepwater and coastal arrays dispersed throughout the western hemisphere starting in 2015 (Cowles et al. 2010). Another NSF-funded initiative, the Critical Zone Observatory (CZO; http://www.criticalzone.org), freely publishes hydrologic, chemical, and physical data from the vadose zones of seven locations throughout the United States and Puerto Rico (Anderson et al. 2008; Lin et al. 2011). Lake ecologists may access an unprecedented catalog of information amassed by the Global Lake Ecological Observatory Network (GLEON; gleon.org), a grassroots network of scientists integrating scalable environmental data from lakes around the world (Hanson 2008; Kratz et al. 2006).

Here we introduce an observatory poised to become a valuable resource for fisheries scientists: the National Ecological Observatory Network (NEON). The observatory is an NSF-funded project currently being constructed by an independent 501(3)(c) nonprofit corporation (NEON, Inc.; headquartered in Boulder, Colorado). The explicit mission of NEON is to enable continental-scale ecological forecasting (i.e., identifying broad-scale patterns across North America and using these to help predict future trends) by providing infrastructure and high-quality, standardized data collected throughout the United States, including Alaska, Hawaii, and Puerto Rico. Specifically, NEON was explicitly designed to address Grand Challenge questions in the environmental sciences put forth by the National Research Council (NRC 2001). NEON-generated data are thus strategically intended to provide standardized observations and experimental data to increase understanding of how (1) climate change, (2) land use change, and (3) invasive species interact to impact (1) biogeochemical cycles, (2) biodiversity, (3) ecohydrological processes, and (4) the spread of infectious diseases (Figure 1; NEON 2011).

During the scheduled 30 years of operation, NEON will archive and provide open access to more than 600 data products. Parameters will range from standard descriptive field measurements, such as indicators of water quality (e.g., NO_3 concentrations, total organic matter, and acid neutralizing capacity) to complex metrics derived from multiple variables (e.g., stream metabolism, fish biodiversity, NO_3 flux). Each measurement will be subjected to a rigorous quality assurance/quality control check. All observatory-generated data will be posted to an open-access web portal for research community and general public use. NEON will operate in 60 sites distributed among 20 ecoclimatic domains selected to maximize objective representation of

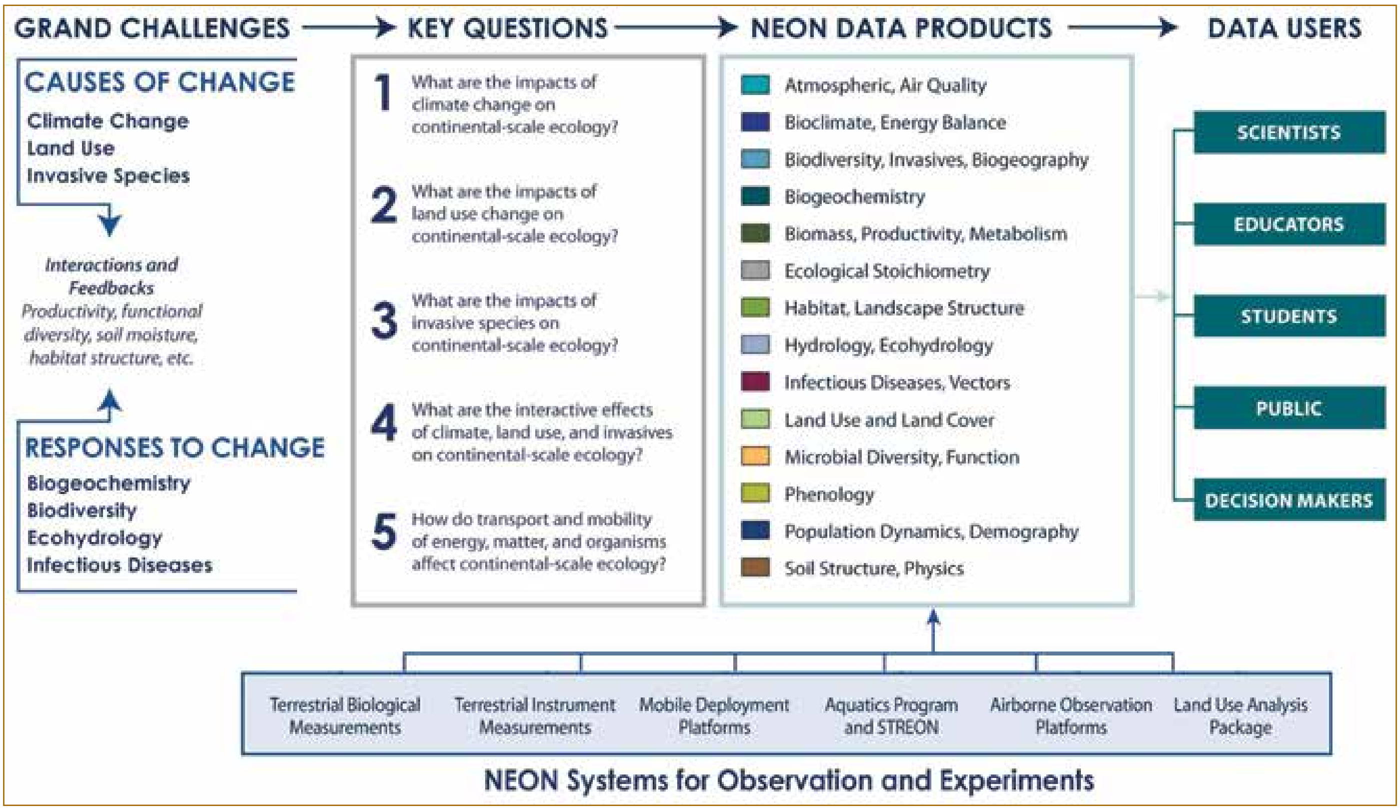

Figure 1. The theoretical basis of the NEON observatory. National Resource Council (NRC) Grand Challenges in environmental sciences have alluded to key questions that NEON data products are meant to help multiple communities address.

continental-scale environmental variability (Keller et al. 2008). The observatory is also a platform upon which researchers identifying an impetus for additional data or seeking to use NEON infrastructure for novel experiments are encouraged to apply for external funding to support their work.

Within NEON, an Aquatic Program will implement a sampling regime for 212 data products from 36 wadable streams, nonwadable rivers, and lakes throughout the United States. The Aquatic Program within NEON aims to address NRC-posited Grand Challenges in aquatic ecosystems with the exception of infectious disease dynamics. Aquatic data will include quantitative metrics characterizing diversity among multiple biological assemblages (fish, invertebrates, macrophytes, algae, and periphyton) and comprehensive biogeochemical, hydrologic, and geomorphic data. The following sections provide an overview of the data products to be derived by the NEON Aquatic Program and how they stand to benefit fisheries scientists. Because of the number of parameters to be collected, a comprehensive description of all planned data products would reach beyond the scope of this article. However, a full, descriptive list of planned data products may be freely accessed online (Keller 2010; Keller et al. 2010).

BIOLOGICAL DATA

Providing comprehensive data that enable the detection of long-term trends in biological assemblages among North American ecosystems represents a fundamental NEON goal. Data products derived from NEON biological collections in aquatic sites will include the diversity, richness, relative abundance, and spatial distribution of microbes, algae, aquatic plants, macroinvertebrates, and fishes. Individual weights and lengths of fishes will also be quantified, with the exception of sensitive species or populations that prohibit such handling. NEON field crews will collect microbial biofilm, algal, and benthic macroinvertebrate community samples two to three times per year and fish sampling will occur once per year in streams and lakes. Zooplankton samples will also be collected in all lakes. Sampling regimes for fish will consist of electrofishing, gill netting, and/or minnow traps depending on site characteristics. During the 30-year period of NEON operations, special attention will be paid to invasive species and data will denote when organisms are not native. Riparian vegetation surveys will be undertaken at each site once per year during peak leaf out. Finally, phenologically important dates associated with riparian vegetation (leaf out, fall, and senescence) that dictate patterns in evapotranspiration and associated trends in stream hydrology will be recorded at each site.

In addition to biological data collected using conventional methodology, NEON will help advance molecular techniques that catalog species and improve biomonitoring efforts. NEON will work with existing partners, including the United States Environmental Protection Agency and Barcode of Life Datasystems, to develop novel DNA barcode databases (Hajibabaei et al. 2007) for select aquatic and terrestrial taxonomic groups that are morphologically difficult to distinguish and speciose. In aquatic ecosystems, a subset of benthic macroinvertebrates will be targeted for DNA barcoding. Though the initial target aquatic taxa for DNA barcoding has yet to be determined, the group will likely possess difficult taxonomic attributes, a ubiquitous distribution and significant potential for biomonitoring applications, such as nonbiting midges (Chironomidae; Raunio et al. 2011).

CHEMICAL AND BIOGEOCHEMICAL DATA

Water quality in aquatic ecosystems is strongly integrated with surrounding terrestrial and atmospheric environments through multiple spatiotemporally heterogeneous processes (Williamson et al. 2008). Such relationships influence fish habitat, water quality, and ecosystem services, though fish may simultaneously shape water chemistry through nutrient transport, via ecosystem engineering (Moore 2006), and by creating biogeochemical hotspots (McIntyre et al. 2008). NEON will provide continuous and discrete chemical data of surface water (up to 35 parameters) at aquatic sites via in situ sensors and water samples collected up to 26 times per year. At lake sites, NEON water chemistry samples will span locations across lake surfaces and at multiple depths to quantify epilimnetic and hypolimnetic processes. These observations will help to define the seasonality of chemical parameters such as total and dissolved nutrients, cations, and anions. Isotopic ratios (i.e., δN^{15}, O^{18}, S^{34}, and C^{13}) in detritus, surface and subsurface water, particulate organic matter, and primary producer samples will also be collected to structure food webs and quantify links between chemical and biological processes and among environments. Because benthic zone sediments act as source, sink, or transformation centers of biogeochemical cycles, NEON will quantify sediment chemistry (up to 23 parameters including dissolved nutrients, cations, and anions) at least annually at all aquatic sites. Complementary metrics pertaining to grain size and structure will help determine sorption and oxygen depletion potentials. At sites where the likelihood of metal contamination is considered significant, NEON will measure sediment and water column metal concentrations. In addition to data derived from grab samples, continuous monitoring sensors will measure parameters such as turbidity, pH, conductivity, dissolved oxygen, temperature, and select nutrients, providing valuable real-time information on the chemical dynamics that affect aquatic organisms.

Aquatic chemistry parameters will also include in-house calculations of high-order biogeochemical metrics. NEON will produce measurements of whole-stream metabolism in wadable streams, which is a key indicator of processes that couple aquatic, terrestrial and atmospheric environments (Carpenter et al. 2005). Changes in land use and subsequent nutrient export from surrounding ecosystems can influence metabolism in receiving waters, ultimately impacting primary production and biological oxygen demand (Mulholland et al. 2001). In some cases, excessive nutrient inputs elevate primary productivity to rates that induce eutrophication, oxygen depletion, and fish kills (Dybas 2005). Given the value of metabolism as an integrator of environmental change, NEON will continuously quantify metabolism in wadable stream sites using a two-stage oxygen-depletion method. Associated data products will include relationships between discharge and stream reaeration rate coefficients, which will enable the calculation of continuous rates of gross primary production and ecosystem respiration per unit channel area and length. Other high-order biogeochemical metrics to be quantified by NEON include flux estimates for nitrogen, phosphorus, and carbon.

HYDROLOGIC, GEOMORPHIC, AND GROUNDWATER DATA

Climate models indicate that global changes in hydrologic cycles are imminent and will significantly affect aquatic ecosystems worldwide. In northeastern North America, heavy precipitation events are predicted to occur more frequently, whereas in the arid southwest precipitation is anticipated to decrease (Solomon et al. 2009). Severe precipitation events may induce water quality degradation in small streams and lakes, because greater fractions of water budgets could potentially be transmitted via overland flow. Such events impact the thermal attributes of aquatic ecosystems: groundwater infiltration is thermally consistent, whereas the temperature of water delivered during events as overland flow may be highly variable (Brown and Hannah 2008). Pulse- and press-dynamic changes in precipitation, water temperature fluctuations, and hydrology associated with climate change will impact the reproductive success of many fishes (Daufresne and Boët 2007). NEON will continuously record stream stage and calculate instantaneous discharge at all wadable stream sites. Additionally, aquatic sites (including lakes) will be instrumented with a network of up to eight riparian monitoring wells (≤30 m deep) to quantify local groundwater contributions at locations where such infrastructure is feasible. Sensors deployed in wells will provide near-continuous data on groundwater level, temperature, and conductivity. The well network will be spatially designed to capture coverage of influent–effluent groundwater chemistry, hydraulic gradients, and flow directions. Coupling NEON biological and biogeochemical attributes with sensor-derived groundwater well, in-stream surface water, and atmospheric/meteorological station data will allow researchers to conduct unprecedented analyses in ecohydrology.

Morphology surveys will be conducted annually to monitor changes in aquatic site physical attributes. At each stream and river site, NEON typically secures access to conduct research within a 1,000-m reach, and morphology surveys will cover this entire extent. Morphological data products in wadable stream systems will include channel attributes such as slope, sinuosity, and the relative linear extent of specific habitat types (i.e., pools, riffles, and runs). Features will be mapped with respect to fixed coordinate systems to assess questions such as whether and how channel attributes evolve over time. Additionally, the abundance, location, and mobility of large woody debris (fundamentally important to aquatic ecosystems; Gregory et al. 2003) will be quantified during morphology surveys. In lakes, detailed bathymetry surveys will be conducted using acoustic technology with high-precision differential Global Positioning Systems.

ATMOSPHERIC, TERRESTRIAL, AND REMOTELY SENSED DATA

NEON data collected outside of aquatic systems will likely also prove a valuable resource in many fisheries science applications. Terrestrial NEON data products consist of physical, chemical, and biological data, including soil metrics, evapotranspiration, phenological attributes (such as leaf senescence and emergence), and biochemical vegetation parameters. Such characteristics directly influence hydrologic cycles and water quality; thus, NEON data will enable investigative efforts relating terrestrial dynamics to hydrogeomorphic attributes in aquatic ecosystems. NEON will quantify stable isotope data signatures from multiple biotic and abiotic components of terrestrial and atmospheric environments. Consequently, stable isotope-based modeling of energy and material subsidies between terrestrial and aquatic food webs, an important phenomenon in both systems (Paetzold et al. 2005; Wipfli and Baxter 2010), will be possible across the network. NEON will collect a comprehensive suite of high-resolution data on atmospheric parameters from tower infrastructures, including total and photosynthetically active solar radiation, deposition, and wind speed/direction. These data may be used to quantify atmospheric controls on the physicochemical attributes of NEON aquatic ecosystems. Additionally, the NEON tower infrastructure will measure the chemical composition of dust and precipitation, thereby facilitating studies investigating deposition impacts on primary productivity in lake and marine ecosystems (Miller et al. 2007; Elser et al. 2009).

Data products will also include remotely sensed information derived from an Airborne Observation Platform (AOP). NEON will collect spectroscopic, photogrammetric, and light detection and ranging (LiDAR) data from flights deployed once annually over all sites in each domain. AOP observations will be converted to multiple high-order data products, such as land cover, canopy moisture, chemistry and structure, and disturbance metrics. These remotely sensed data are meant to bridge scales between satellite and terrestrially derived data. Integrating such information with aquatic and terrestrial observations should facilitate unprecedented analyses in watershed science.

STREON—THE FIRST NEON NETWORK EXPERIMENT

As mentioned above, NEON encourages proposals submitted by external scientists who use observatory facilities to conduct novel experiments. The first among these will be the Stream Experimental Observatory Network (STREON), an experimental program that will serve as a long-term assessment of stream ecosystem responses to drivers of environmental change (eutrophication and the extirpation of large-bodied organisms). STREON will consist of two treatments: (1) the nutrient most likely limiting local primary production (nitrogen or phosphorous) will be enriched by 5× ambient concentrations and (2) large-bodied organisms such as fish and amphibians will be electrically excluded from patches of benthic habitat (sediment baskets) during an annual 8- to 12-week period (Figure 2). Additionally, the likely nonlimiting nutrient (nitrogen or phosphorus) will be chronically added at an N:P ratio of 20:1. Nutrient enrichment treatments will be applied immediately downstream of the regular aquatic NEON reach in 10 sites (Table 1, Figure 2), and consumer exclusion apparatuses (and control replicates) will be deployed in both reaches. Data associated with STREON will include all standard NEON aquatic site measurements collected in both reaches. Additionally, sediment baskets linked to the consumer exclusion treatment will be incubated in closed recirculation chambers to quantify benthic metabolism and nutrient uptake.

Past chronic nutrient enrichment experiments have demonstrated distinct temporal thresholds of whole-ecosystem effects and elevated fish growth rates in treatment reaches (Benstead et al. 2007), and studies similar to the consumer exclusion component have revealed how fishes and other large-bodied organisms induce trophic cascades and/or serve as ecosystem engineers (Greathouse et al. 2006). What renders STREON unique from past efforts is the scope: the experiment will run over a 10-year period in 10 geoclimatically distinct streams across the continent. STREON will operate using standardized data quality assurance procedures to ensure that the experiment is as consistent as possible among sites. As with all NEON-generated information, STREON data will be open access, quality assured/quality controlled and available to the public via a web portal.

Metric and Protocol Development

The metrics to be collected and posted by NEON were specifically selected to help address NRC Grand Challenges in the environmental sciences and were identified during the planning and design phases of NEON development. From 2005 to 2011, NEON held multiple workshops and meetings intended to solicit recommendations on metric selection from external researchers in various subdisciplines of ecology. The resulting comprehensive suite of data products to be collected may be found in Keller (2010) and Keller et al. (2010). However, the NEON suite of data products will not necessarily remain static during the 30 years of operations: researchers may apply for funding (through agencies external to NEON) to expand the scope of data products that NEON collects (explained further in The NEON Structure: Current and Future section below).

For each NEON-generated data product, including all described in the preceding sections, specific protocols defining field and laboratory procedures will be written by NEON staff ecologists and peer-reviewed by active members in the research community. Protocol methodology will attempt to outline the best-known sampling practices for NEON field technicians. Preliminary protocol drafts are distributed to a voluntary working group of scientists external to NEON for review. Working group members possess the expertise required to assess such protocols and include scientists from academia, government agencies, and nonprofit organizations. For example, the aquatics technical working group reviews all aquatics program protocols and is comprised of 18 aquatic ecologists from nine universities or colleges, three federal agencies, and two nonprofit research institutions (currently active members of all working groups are listed on the NEON website). Finalized protocols will be made available to the community as open-access online resources so that researchers wishing to apply NEON methodology to maximize the comparability of data they collect may do so.

Protocols are developed to maximize data comparability among sites. Wherever possible, NEON personnel will apply identical methodology across sites. Procedures applied will represent those most appropriate for the setting where local environmental conditions significantly affect the efficacy of a certain method. For instance, when sampling benthic macroinvertebrates, Surber samplers will be used in mid- to high-gradient streams with hard substrates, whereas sites with sandy or silty substrates will be sam-

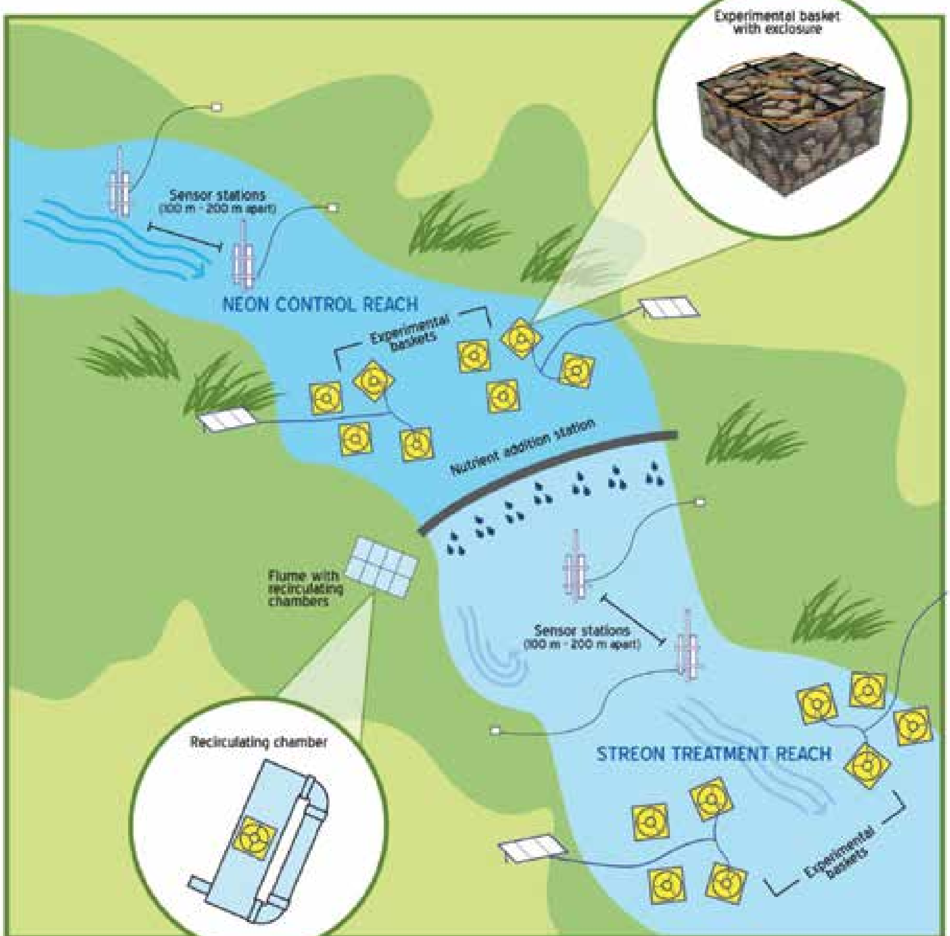

Figure 2. Experimental design of the STREON program at a typical site.

TABLE 1. NEON candidate aquatic sites and examples of fish species found in these water bodies. Sites listed are pending land use agreements (for site updates visit the NEON website). Numbers in the first column correspond to those illustrated in Figure 4. Italicized stream names denote sites in the STREON program.

Site	Name, State	Watershed area (km2; lotic systems) or surface area (ha; lakes)	Fish community attributes at site
1	West Branch Bigelow Creek, MA	0.3	No fishes present
2	Sawmill Brook, MA	4.0	No fishes present
3	*Baisman Run, MD*	1.7	Six species including brook trout (Salvelinus fontinalis), rosyside dace (Clinostomus funduloides), and longnose dace (Rhinichthys cataractae)
4	Posey Creek, VA	2.2	Currently unknown, but likely mottled sculpin (Cottus bairdi), creek chub (Semotilus atromaculatus), and blacknose dace (Rhinichthys atratulus)
5	Suggs Lake, FL	31.5	Fourteen recorded species, including spotted gar (Lepisosteus oculatus), bowfin (Amia calva), and warmouth (Lepomis gulosus)
6	Barco Lake, FL	10.1	Warmouth, largemouth bass (Micropterus salmoides), and bluegill (Lepomis macrochirus)
7	Ichawaynochaway Creek, GA	2,683.2	Fifty recorded species including goldstripe darter (Etheostoma parvipinne), shoal bass (Micropterus cataractae), and spotted bullhead (Ameiurus serracanthus)
8	*Río Cupeyes, PR*	11.3	American eel (Anguilla rostrada), mountain mullet (Angonostomus monticola), and bigmouth sleeper (Gobiomorus dormitor)
9	Río Guillarte, PR	11.9	Currently unknown; likely similar to Río Cupeyes
10	Lake Clara, WI	27.4	At least five species characteristic of north-temperate lakes, including yellow perch (Perca flavescens), largemouth bass, and northern pike (Esox lucius)
11	Pickerel Creek, WI	34.9	Currently unknown
12	*Kings Creek, KS*	12.4	Twenty recorded species including orangethroat darter (Etheostoma spectabile), orangespotted sunfish (Lepomis humilis), and shorthead redhorse (Moxostoma macrolepidotum)
13	McDowell Creek, KS	214.4	Thirty-six recorded species, including carmine shiner (Notropis percobromus), southern redbelly dace (Phoxinus erythrogaster), and longnose gar (Lepisosteus osseus)
14	LeConte Creek, TN	9.1	Brook trout and mottled sculpin (Cottus bairdi)
15	*Walker Branch, TN*	0.4	Creek chub and western blacknose dace (Rhinichthys obtusus)
16	Black Warrior River, AL	15,159.3	One hundred twenty-six recorded species including Tuskaloosa darter (Etheostoma douglasi), redeye bass (Micropterus coosae), and black redhorse (Moxostoma duquesnei)
17	Lower Tombigbee River, AL	47,102.4	One hundred twenty-one recorded species, including paddlefish (Polyodon spathula), river redhorse (Moxostoma carinatum), and crystal darter (Ammocrypta asprella)
18	*Mayfield Creek, AL*	17.0	Currently unknown, but could include >25 species. Supports populations of Tombigbee darter (Etheostoma lachneri), least brook lamprey (Lampetra aepyptera), and bluehead chub (Nocomis leptochephalus)
19	Prairie Pothole, ND	11.0	Currently unknown; likely supports populations of brook stickleback (Culea inconstans) and black bullhead (Ameirus melas)
20	Prairie Lake, ND	30.0	Currently unknown; likely similar to Prairie Pothole lake
21	Arikaree River, CO	2,874.9	Nineteen species, including brassy minnow (Hybognathus hanksinsoni), northern plains killifish (Fundulus kansae), and orangethroat darter
22	South Pond, OK	0.8	No fishes present
23	Pringle Creek, TX	18.1	Currently unknown; likely supports populations of mimic shiner (Notropis volucellus), blackstripe topminnow (Fundulus notatus), and logperch (Percina caprodes)
24	Bozeman Creek, MT	48.7	Currently unknown
25	Blacktail Deer Creek, WY	38.9	Brook trout
26	Fool Creek, CO	2.4	Currently unknown
27	Como Creek, CO	4.8	Greenback cutthroat trout (Oncorhynchus clarki stomias)
28	*Sycamore Creek, AZ*	345.0	Longfin dace (Agosia chrysogaster) and desert sucker (Pantosteus clarki)
29	Red Butte Creek, UT	16.7	Bonneville cutthroat trout (O. clarki utah)
30	East Branch Planting Creek, OR	1.6	Currently unknown; likely supports populations of coastal cutthroat trout (O. clarki clarki)
31	*McRae Creek, OR*	5.2	Coastal cutthroat trout
32	Providence Creek, CA	1.3	No fishes present
33	*Convict Creek, CA*	52.1	Brook trout (Salvelinus fontinalis), brown trout (Salmo trutta), rainbow trout (Oncorhynchus mykiss)
34	Toolik Lake, AK	146.7	At least five species including lake trout (Salvelinus namaycush), Arctic grayling (Thymallus arcticus), and round whitefish (Prosopium cylindraceum)
35	*Oksrukuyik Creek, AK*	73.5	Arctic grayling and slimy sculpin (Cottus cognatus)
36	*Caribou Creek, AK*	30.7	Arctic grayling and slimy sculpin

pled using hand corers. Posted data will specify methodological approaches, and the open-access protocols used to collect the data will allow interested researchers to determine the rationale concerning methodological decisions. Sample collection timing will also be coordinated to maximize data comparability among sites. NEON will identify periods where maximum biological diversity is expected for each target assemblage using externally collected historical data from each domain.

NEON Site Selection Process and Aquatic Sites

Sites in the NEON network are chosen to simultaneously maximize representation among major North American ecosystems and allow researchers to address environmental questions of regional concern. To distribute sites throughout major ecological gradients of North America, NEON used multivariate geographic clustering (Hargrove and Hoffman 1999) to partition the continental United States, Alaska, Hawaii, and Puerto Rico into 20 ecoclimatic domains. All domains (excluding Hawaii) include one to three aquatic sites that fall into two categories: core sites, which will remain fixed in place during the entire 30 years of NEON operations, and relocatable sites, which are intended to move approximately every 5 years to capture variation within a domain and address regional questions of interest. Sites were selected to represent the greatest degree of characteristic ecological attributes of the corresponding domains. Core sites typically consist of ecosystems that are minimally impacted by anthropogenic stressors. Relocatable sites may be in areas impacted by anthropogenic stressors and are usually paired with either core sites or other relocatables to allow contrasting measurements between impacted and relatively intact ecosystems. The data collected from all sites may be used to extrapolate relationships that identify the driving causes of long-term ecological changes to areas not sampled but where partial, extensively sampled, or gridded information is available.

Currently, the candidate aquatic sites in the NEON network include 26 wadable streams, three nonwadable rivers, and seven lakes representing characteristic aquatic ecosystems among a majority of North American ecoregions (Table 1, Figures 3 and 4). Sites are considered as candidates until a land use agreement is obtained. NEON aquatic site selection is informed by external scientific input from those familiar with the respective domain and follows the same criteria of terrestrial and atmospheric site selection: core sites are situated in relatively intact watersheds, whereas relocatable sites may be anthropogenically impacted. Wherever possible, aquatic sites are located adjacent to (i.e., <5 km) NEON tower and terrestrial sites to help couple data among ecosystems. NEON lotic ecosystem sizes range from small, first-order, fishless streams to large rivers that support highly diverse fish communities. The network of sites in Domain 8, the Ozarks Complex, may prove particularly valuable for fisheries and aquatic ecosystem science because they consist of three sites with nested catchments of various sizes within a large river watershed. Domain 8 sites were specifically selected to span the river continuum (Vannote et al. 1980) of the Tombigbee River watershed and include reaches with more than 100 recorded fish species.

The NEON Structure: Current and Future

NEON is an NSF-funded project managed and maintained by an independent, nonprofit corporation (NEON, Inc.) implemented through the Large Facilities Office (LFO). Examples of well-known observatories managed under this program include the Arecibo and Gemini Satellite Observatories. Programs implemented through the LFO typically undergo a multiyear review process with incremental developmental steps prior to operations termed the major research equipment and facilities construction (MREFC) process. Construction funds were awarded in fiscal year 2011; a 5-year construction phase (where sites are fitted with sensors and data collection begins) followed by a 30-year operations phase is now set to ensue. Within each domain, NEON crews stationed in local offices will perform field operations. Central NEON headquarters is located in Boulder, Colorado.

All data will be posted on an open-access, NEON-maintained Internet portal. The portal system will include comprehensive search interfaces, filtering capabilities (e.g., searching within regional and/or date criteria), and decision-support functions to help investigators become fully aware of all available data pertinent to their inquiries. The data acquisition portal is currently under development and many design specifications have yet to be finalized. However, NEON will collaborate with several existing data management initiatives, such as the National Water Quality Monitoring Council and BioOne, to assist with portal development. External researchers will also be consulted to help maximize data portal functionality. Regardless of the final design, an open-source metadata structure and provenance process will ensure that users understand where and how all data are derived. All data will undergo stringent quality assurance/quality control product definition, statistical, and modeling analysis to ensure the identification of erroneous readings. Wherever possible, data will be cross-checked using related sensors or measurements among the NEON data streams. Researchers and the public will be able to access NEON-derived design and protocol documents using the web portal to ensure data comparability and methodological repeatability outside of the observatory. For instance, the standardized, peer-reviewed field protocol applied for fish sampling will be downloadable so that reliably comparable data may be collected elsewhere.

Educational resources and tools are being developed at NEON to ensure that observatory-generated information, including data, is accessible and usable for all interested users. In partnership with stakeholder communities, NEON will employ a variety of approaches to engage communities in the scientific process. Planned educational activities include social media applications, online learning modules, citizen science projects, student research and internship programs, short courses, and workshops to help individuals at all levels of professional development effectively use observatory-generated data. Graduate students from any institution will be able to participate in a competitive field and data analysis course to help familiarize themselves with NEON resources. The NEON web portal will be an interface to many educational resources, including online learning modules for students hoping to use NEON data. Citizen science programs will enable participants to collect, contribute, interpret, and visualize scientific data that may significantly contribute to scientific inquiry. Project Budburst, the first among such initiatives (comanaged by the Chicago Botanical Garden and NEON), provides an interface for amateur botanists to report the dates of phenological events such as leaf out and senescence at any location. Interested researchers may now access thousands of phenological event data recorded across the country over the past 4 years.

NEON aims to be a dynamic and valued resource by actively encouraging the scientific community to develop research projects that leverage NEON data, facilities, and infrastructure. Currently, the NSF Macrosystems Biology program, supporting research on biological systems at regional to continental scales, is a principal avenue for fostering scientific collaboration with NEON. Other NSF funding programs that have encouraged NEON collaboration to date include the Research Coordination Networks and Campus Cyberinfrastructure–Network Infrastructure and Engineering Program. New collaborative efforts that leverage NEON may also be funded by agencies other than NSF or nongovernmental institutions. Proposals that include the use or leveraging of NEON assets may be submitted by universities, nonprofit institutions, non-academic organizations, or federal agencies. Decisions regarding the use of NEON assets in novel work will be assessed for technical and logistical feasibility by NEON staff in accordance with policies and procedures currently in development and subject to NSF approval. Quantitative, interdisciplinary, and systems-oriented research on biological processes and their interactions with environmental change at continental scales will be particularly encouraged. Smaller scale initiatives, including new technology testing and implemention, will also be possible and promoted through collaborations with NEON scientists. Finally, collaborative research may be fostered through student internships with individuals mentored by both external and NEON scientists.

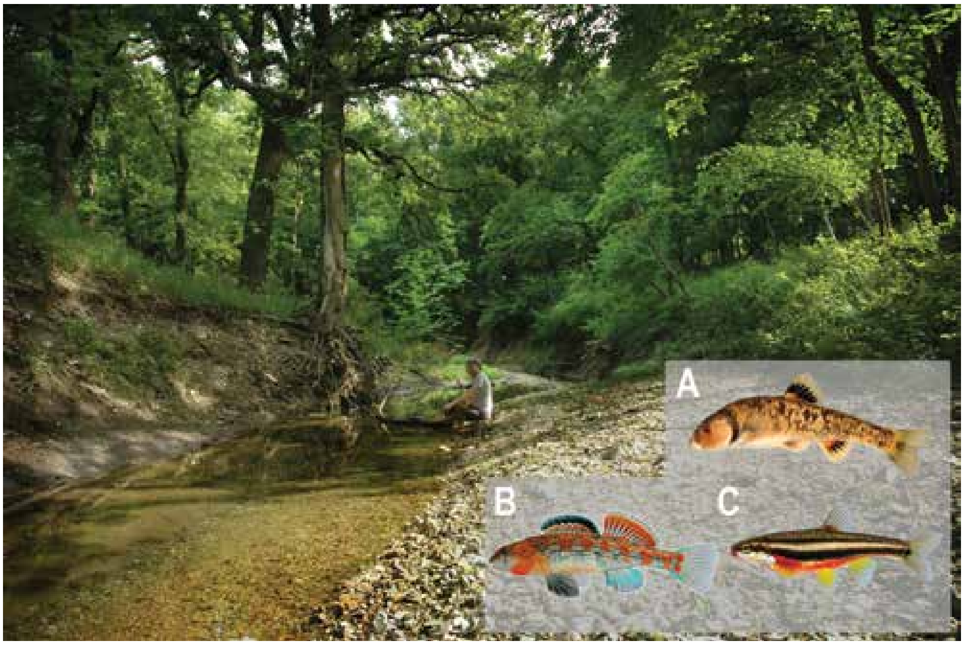

Figure 3. Kings Creek, a NEON candidate core aquatic and STREON site located within the Konza Prairie Biological Station near Manhattan, Kansas. NEON will collect population estimates of fishes, including (A) central stoneroller, (B) orangethroat darter, and (C) southern redbelly dace in Kings Creek for 30 years. Additionally, data from the STREON experiment will allow any interested researcher to explore how populations of these fishes respond to chronic nutrient enrichment and how their extirpation might impact ecological processes in the benthic zone.

Figure 4. Map of NEON North American domains and locations of aquatic sites in the observatory. Site numbers correspond to those listed in Table 1.

Successful analyses and forecasting in fisheries science at broad scales amid pervasive global environmental change will require unprecedented scientific resources. NEON aims to become a transformative tool in the ecological sciences by providing high-quality, nonproprietary, and comprehensive data across spatiotemporal scales beyond the capabilities of individual laboratories. The combined suite of aquatic, terrestrial, and atmospheric data generated by NEON will particularly enhance investigations of material and energy exchanges across apparent ecosystem boundaries, which are increasingly recognized as critically important in aquatic ecosystems (Lamberti et al.

2010). To learn more about NEON, including the observatory structure, data products, working group members, and construction updates, please visit the NEON website (neoninc.org).

ACKNOWLEDGMENTS

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SIUC Subunit Blends Research and Service in Pursuit of Professional Development

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Members of the Southern Illinois University Carbondale (SIUC) Subunit of the Illinois Chapter of the American Fisheries Society take a multi-faceted approach to promote the conservation of aquatic resources through personal, professional, and community development. From teaching youths about aquatic ecology and fish identification, to the development of the inaugural "Carp-A-Thon" for area anglers, the SIUC IL-AFS Subunit serves as an important community resource. This past year alone, members planned and participated in well over a dozen fisheries-related outreach events, including the Illinois Department of Natural Resources' Urban Fishing program, where members had the chance to introduce youngsters to the joys of angling and the importance and value of the great outdoors.

Opportunities abound for Subunit members to develop their fisheries and interpersonal skills by electrofishing area lakes, generating stock assessment reports, and presenting their findings to anglers and members of the community. This year, members experienced a unique opportunity to culture freshwater prawn as part of an SIUC-sponsored research project. At the end of the summer, the tasty crustaceans were harvested and sold to students and faculty of SIUC and greater Southern Illinois community as a fundraiser for the Subunit. Additionally, members gained pond-culture experience, learned about prawn biology, and collected data for a bioenergetics study.

The next few months are an exciting time for the SIUC IL-AFS Subunit, as members are currently developing monthly workshops to give new students out-of-the-classroom learning opportunities in electrofishing, lab and culture techniques, pond management, and boat maintenance, safety, and operation. These opportunities build professional skill sets, human and resource networks, and a sense of camaraderie among both new and old members of the fisheries community at SIUC. The SIUC Subunit also serves as an important means of mentoring undergraduate students by incorporating real field and lab experiences to supplement traditional classroom-style learning. Graduate students benefit from undergraduate assistance that is always available. This relationship is important to the growth of the program and describes the Subunit's mission. Encouraging academic excellence, robust research productivity, and community service are the focus of the SIUC IL-AFS Subunit. In addition to serving locally, the Subunit also has a history of helping the Illinois Chapter and AFS Sections at various levels. Through the Subunit, members feel a connection to our local cadre of fish-heads, as well as AFS and the broader fisheries community.

To learn more about the SIUC IL-AFS Subunit, please visit their website at http://fishstudent.rso.siu.edu. For more information on establishing a Student Subunit at your college or university, contact your state AFS Chapter.

(Left): SIUC IL-AFS member Jake Norman instructs beginning anglers on how to properly cast a rod and reel during the 2012 Illinois Department of Natural Resources' Urban Fishing program. Through this vital community resource, many children had the opportunity to catch their first fish, thus generating a newfound enthusiasm for fishing within the youngest members of the Southern Illinois community. (Center): From May through September 2012, SIUC IL-AFS members cultured freshwater prawn in SIUC-provided ponds. Members harvested the prawn in late September, and sold them by the pound as a fundraiser for the Subunit. Not only did Subunit members witness how tasty freshwater prawn are, but they also gained experience on data collection for a bioenergetics study and learned about prawn biology and pond culture techniques. Above, SIUC IL-AFS member and prawn fundraiser organizer Bonnie Mulligan holds a "blue claw" male prawn during the harvest. (Right): SIUC IL-AFS member and past-president John Bowzer holds a contestant's carp entry for the 1st annual Southern Illinois "Carp-A-Thon". The fishing tournament was sponsored in part by the SIUC IL-AFS, and served as both a platform to both raise awareness of the Bighead and Silver carp infiltration of local waterways and a fundraiser for the Subunit. Prizes were awarded to the anglers for "Biggest Carp" and "Top Ten Heaviest Fish."

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The **American Fisheries Society Student Writing Contest** recognizes students for excellence in the communication of fisheries research to the general public.

Undergraduate and graduate students are encouraged to submit a 500- to 700-word article explaining their own research or a research project in their lab or school. The article must be written in language understandable to the general public (i.e., journalistic style). The winning article will be published in ***Fisheries.***

Students may write about research that has been completed, is in progress, or is in the planning stages. The papers will be judged according to their quality and their ability to turn a scientific research topic into a paper for the general public and will be scored based upon a grading rubric. Check the AFS Web site (www.fisheries. org) awards page for the grading rubric.

American Fisheries Society Adopts New Policy, Encourages Efforts to Understand and Limit Effects of Lead in Sport Fishing Tackle on Fish and Wildlife

Jesse Trushenski and Paul Radomski

American Fisheries Society, Resource Policy Committee

In October of 2012, the American Fisheries Society (AFS) voted to adopt a new policy statement on "Lead in Sport Fishing Tackle." Like all AFS policies, this document represents the collective voice of the oldest, largest, and most influential professional organization dedicated to the fisheries sciences. The new policy draws attention to the negative effects of lead in the environment and encourages scientists, regulatory authorities, tackle manufacturers, the sport fishing community, and other stakeholders to work together to understand and limit any negative effects of lead-based tackle (e.g., sinkers, jigs) on fish and other organisms.

Lead is a naturally occurring but toxic element. Because of its negative effects on human and animal health, lead is banned in products such as gasoline, paint, and solder in many countries. However, lead is still commonly used in fishing tackle because it is readily available, dense, malleable, and inexpensive. Though lost fishing tackle can remain intact and relatively stable for decades or centuries in aquatic systems, if ingested by animals, the lead in these products becomes more biologically available and can result in lethal exposures. The effects of ingesting such tackle were established in waterbirds in the 1970s and 1980s, following lead poisoning events in localized populations of loons and swans. Although population-level effects have not been unequivocally demonstrated and lost tackle represents a relatively small fraction of the total amount of lead found in the environment (surface runoff, atmospheric deposition, and mining activities are more significant sources), given the likelihood of ingestion and the magnitude of organism-level effects of exposure following ingestion, it would seem prudent to assess, understand, and limit the negative effects of lead in sportfishing tackle on fish and other aquatic organisms.

This issue was reviewed by members of the AFS Resource Policy Committee (RPC), under the principal leadership of Paul Radomski, Tom Bigford, and Jesse Trushenski. In cooperation with a special committee established by then AFS President Wayne Hubert, Radomski and the other members of the RPC prepared a draft policy statement. Following review by the AFS RPC, governing board, and membership at large, the Society adopted the policy, calling for stakeholders to address the potential effects of lead in sportfishing tackle on fish populations.

Accordingly, the policy of the AFS, in regard to lead in sport fishing tackle, is to

1. Recognize that lead has been known for centuries to be toxic to biological organisms. Thus, the loss and subsequent ingestion of lead sinkers and jigheads by aquatic animals and the potential ramifications of lead ingestion is a natural resource management issue.
2. Understand that the impact of ingested lead on individuals of certain waterfowl species is generally accepted, but population-level impacts on fish and wildlife species are not well documented. Although conclusive scientific proof of these effects is not currently available, actions to inform, educate, and encourage sportfishing tackle manufacturers, users, and researchers to reduce future introductions of lead into aquatic ecosystems appears advisable. Accordingly, collaborate with fish and wildlife professionals, tackle manufacturers, anglers, policy makers. and the public to encourage the use of non-lead forms of small fishing sinkers and jigheads that are protective of potentially affected fish and wildlife populations.
3. Encourage scientifically rigorous research on lead tackle aimed at generating toxicological and environmental chemistry data including bioavailability assessments; support monitoring and modeling of exposure and effects on at-risk populations; encourage studies predicting consequences of exposure and long-term population-level effects of different tackle material; and encourage studies on reducing the economic and social barriers to nontoxic fishing tackle development and use.
4. Recognize that the hunting and angling communities can be important advocates and forces of change regarding natural resources issues and support educational efforts to promote greater public awareness and understanding of the consequences of lead exposure in wildlife species and the potential gains in environmental quality from use of lead-free fishing tackle.
5. Update policy language as focused research provides additional data on lead tackle-related impacts.

To read the full text of the new policy statement or any of the society's current policies, please visit the American Fisheries Society online at http://fisheries.org/policy_statements.

MISSION STATEMENT

Fisheries is the monthly peer-reviewed membership publication of the American Fisheries Society (AFS). Its goal is to provide timely, useful, and accurate information on fisheries science, management, and the fisheries profession for AFS members. Some types of articles which are suitable for *Fisheries* include fishery case histories, review or synthesis articles covering a specific issue, policy articles, perspective or opinion pieces, essays, teaching case studies, and current events or news features. We particularly encourage the submission of short-form (under 5 typeset pages) "mini-review" articles. Our goal is to move towards four science-based papers in each issue. We will waive page charges for even shorter articles (under 2 typeset pages) on such articles as current events in fisheries science, interviews with fisheries scientists, history pieces, informative how-to articles, etc. We also encourage articles that will expose our members to new or different fields, and that recognize the varied interests of our readers. Research articles may be considered if the work has broad implications or applications and the subject matter can be readily understood by professionals of a variety of backgrounds. *Fisheries* is the Society's flagship publication and is the mostly widely read fisheries science publication in the world. Accordingly, content submitted for consideration should appeal broadly to fisheries professionals and speak to the interests of the AFS membership. Lengthy, highly technical, or narrowly focused research articles are better suited to the AFS technical publications, and we encourage authors to consider the other AFS journals as venues for these works.

REVIEWED ARTICLES

***IMPORTANT**

The maximum length of articles accepted in *Fisheries* is 10 typeset pages (including photos, figures, tables, pull quotes, titles, translations, etc.). One full page of article text with absolutely no figures, tables, pull quotes, titles, headers, translations, or photos is approximately 880 words or 6100 characters including spaces. Please adhere to this standard, taking figures and other non-text content into consideration, when preparing manuscripts for submission to *Fisheries*.

Features, Perspectives, and Review Articles

We encourage submission of topical manuscripts of broad interest to our readership that address contemporary issues and problems in all aspects of fisheries science, management, and policy. Articles on fisheries ecology and aquatic resource management; biology of fishes, including physiology, culture, genetics, disease, and others; economics and social issues; educational/administrative concepts, controversies, techniques, philosophies, and developments; and other general interest, fisheries-oriented subjects will be considered. Policy and issue papers are welcome, particularly those focusing on current topics in fisheries policy. As noted above, we are particularly interested in mini-reviews, which should concisely but comprehensively summarize a topic under 5 typeset pages or less. Papers are judged on scientific and professional merit, relevance, and interest to fisheries professionals. Features and perspectives generally should not exceed 4,500 words (excluding references and tables) and should not cite more than 40 references. Please consult the managing editor PRIOR to submission for a length or reference limit exemption for review articles or articles of Society-wide significance.

Please submit your manuscript online using our manuscript tracking website at http://mc.manuscriptcentral.com/fisheries. If you cannot submit your manuscript online, please e-mail or phone the managing editor, Sarah Fox, for instructions: sgilbertfox@fisheries.org or 301-897-8616 x220 (for fastest response, please e-mail).

Essays

Essays are thought-provoking or opinion articles based upon sound science. Essays may cover a wide range of topics, including professional, conservation, research, AFS, political, management, and other issues. Essays may be submitted in conjunction with a full feature article on the same topic. Essays can be up to 2,000 words, may include photographs or illustrations, and should not cite more than eight references. However, essays should provide scientific documentation, unlike unreviewed opinion pieces (below). Essays are peer-reviewed based on the following criteria: contribution to the ongoing debate, logical opinion based on good science, persuasiveness, and clarity of writing. Reviewer agreement with the opinion of the views expressed is not a criterion. Essays do not have page charges or abstracts. Essays should be formatted and submitted online as described above.

Fisheries Education

Fisheries will consider publication of case studies and other articles specifically intended as teaching tools. These articles, including case studies or short topical summaries, should be formatted to be used for teaching aids for courses taught at the undergraduate level. Fisheries Education articles should be readily understood by undergraduate students with basic training in biological/ecological sciences, and include background information, discussion questions, teaching notes, and references. Peer review of teaching case studies and educational topics will be handled by a special committee of the AFS Education Section.

Materials to Submit

- Assemble manuscripts in this order: title page, abstract page, text, references, tables, figure captions. Tables may be included at the end of the article file or may be submitted as separate files. Figures should not be embedded in the article file and should be submitted separately.
- Authors are strongly encouraged to submit a word processing file in either Word or plain text format.
- Figures/images should be in TIF (preferred), JPG, or PDF formats, and tables should be in Excel or Word formats.
- Word count is extremely important. (See limits for article types above.)
- The cover letter should explain how your paper is innovative, provocative, timely, and of interest to a broad audience. It should also include a list of potential reviewers who can provide an unbiased, informed, and thorough assessment of the manuscript. The cover letter can also be used to provide further explanation, if part of the information has been published or presented previously.
- Also in the cover letter, please include:
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  2. A cover teaser: 4-5 words that will go onto the cover of the magazine.

General Instructions

- Consult current issues for additional guidance on format.
- Manuscripts should be double-spaced, including tables, references, and figure captions.

- Leave at least a 1-in margin on all sides. Indent all paragraphs. Number pages sequentially and use continuous line numbering,
- Use dictionary preference for hyphenation. Do not hyphenate a word at the end of a line. Use *Chicago Manual of Style, 14th edition* to answer grammar or usage questions.
- The first mention of a common name should be followed by the scientific name in parentheses. Our standard is C*ommon and Scientific Names of Fishes from the United States, Canada, and Mexico, 7th edition*.
- Define abbreviations the first time they are used in the text.
- Spell out one-digit numbers unless they are units of measure (e.g., four fishes, 3 mm, 35 sites). Use 1,000 instead of 1000; 0.13 instead of .13; % instead of percent.
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- Type the abstract as one paragraph. You can copy and paste this into the online form.
- Do not cite references or use abbreviations in the abstract.
- Ensure that the abstract concisely states (150 words maximum) why you did the study, what you did, what you found, and what your results mean.

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- See "General Instructions."
- Set all type at left. Boldface primary subheads and italicize secondary subheads.
- Insert tabs—not spaces—for paragraph indents.
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- Double-space everything, including the table title and column headings.
- Use single horizontal lines to separate column heads and to indicate the end of the table—other horizontal lines are not needed. Never use vertical lines.
- Use sentence-style captions for tables, not fragments.
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Illustrations

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- For review on the manuscript tracking system, we prefer digital photos (or scans). However, original film photos and slides can be used for final production. The managing editor or production editor will contact you after acceptance and let you know when to send original photos.
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All manuscripts will be reviewed by two or more outside experts in the subject of the manuscript and evaluated for publication by the science editors and senior editor. Authors may request anonymity during the review process and should structure their manuscripts accordingly.

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UNREVIEWED ARTICLES

Unit News and Other Departments

AFS members are encouraged to submit items for the Unit News, Member Happenings, Obituaries, Letters to the Editor, and Calendar departments. Dated material (calls for papers, meeting announcements, and nominations for awards) should be submitted as early as possible, but at least eight weeks before the requested month of publication. AFS Unit News and Letters should be kept under 400 words and may be edited for length or content. Obituaries for former or current AFS members may be up to 600 words long and a photo of the subject is welcome. Do NOT use the online manuscript tracking system to submit these items—the text and 300 dpi digital photos (TIF or JPG) for all departments except the Calendar should be e-mailed to the managing editor at sgilbertfox@fisheries.org, or mailed to the address below.

Calendar

Calendar items should include, in this order: the date, event title, location, and contact information (including a website, if there is one), and should be sent to the editor at sgilbertfox@fisheries.org.

Student Angle

For information about submitting a Students' Angle column, please contact Student Subsection President Jeff Fore at jdfore@mizzou.edu.

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Brief items for the Fisheries News section are encouraged. Typical items include conservation news, science news, new programs of significance, major policy or regulatory initiatives, and other items that would be of interest to Fisheries readers. News items for the section should be no more than a few paragraphs; please consult the managing editor about submitting longer news articles.

Fisheries Forum (formerly Guest Editorials)

Authors are encouraged to submit most opinion pieces about fisheries science or management as essays for peer review. Occasionally, editorials about professional or policy issues may be inherently unsuitable for a scientific review. Sometimes these pieces are submitted by a committee, agency, or organization. Editorials should be 750–1,500 words, may be edited for length or content, and referred for outside review or rebuttal if necessary. A disclaimer may accompany Fisheries Forum editorials stating that the opinion is that of the author and not the American Fisheries Society.

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Please contact Book Review Editor Francis Juanes at 413-545-2758, juanes@uvic.ca, if you want to be added to the list of potential book reviewers.

New books (preferably two copies) submitted for review should be sent to:

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The Four Fs of Fish: Communicating the Public Value of Fish and Fisheries

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"Fish? Why fish?!" This is a common question we are often asked by those outside our field upon learning our profession. They are curious as to why we devote our lives to the study, conservation, restoration, and propagation of fish and associated habitats. This question can come anywhere and at any time. Though it is a common inquiry, do we, as professionals and as a profession, have a good answer?

Effectively demonstrating the value of fish and the fisheries supply chain they create is as important for the future of our own profession as for the fish. This, however, is no easy task. The average American eats approximately 15.8 pounds of fish and shellfish per year (NOAA 2010) and less than 14% of adult Americans report that they participate in recreational fishing (USFWS 2012). So, in general, Americans have little to no direct interaction with fish. In spite of this, our role as fisheries professionals is to clearly articulate to the public and policy makers that fish are important and have value – locally, regionally, nationally, and internationally. Such demonstration of public value ensures that fish and fisheries are afforded appropriate consideration in decision making – from the dinner table to the United Nations general assembly floor. Fish are important; no, they are more than important. They are essential to the survival of mankind. Fish, after all, directly or indirectly contribute to subsistence, livelihoods, health, and prosperity for much of the world.

As fisheries professionals, we are all passionate about fish. This personal and professional passion emanates for many different reasons, as shown by the diversity of the American Fisheries Society sections and membership. However, our drive is often hard to explain to someone who doesn't share the same interest and wonder for fish, their habitats, and fisheries.

We [*the authors*] propose "The Four Fs of Fish": Food, Finances, Fun, and Function as a means to effectively communicate the public value of fish and fisheries. Surely, there are other values, but these four can start the discussion and hone our passion into something tangible to the public and policy makers.

FOOD

Perhaps the most direct argument to make in support of the importance of fish and their habitats is food. Capture fisheries are the last large-scale wild food resource in the world and aquaculture is a quickly growing sector. Both provide essential protein and nutrients to many across the globe. Fish directly provide more than 1.5 billion people with almost 20% of their animal protein and another 3.0 billion with at least 15% (FAO 2010). This equates to more than 40% of the world's human population.

Fish are also an important indirect source of protein for many others who generally do not realize it. Approximately 12.4% of global fishery production is reduced to fish meal and fish oil (FAO 2009), which is subsequently formulated into specialized feed for livestock and aquaculture operations. So, choosing between chicken and fish as meal options may, in fact, be choosing fish or reprocessed fish. We can do a better job of emphasizing the role of fish in other protein sources. For example, instead of asking "how's the chicken?" to someone enjoying a piece of fried chicken, ask "how's the fish?" By helping people understand the supply chain that leads to their meals, we will help them appreciate the importance of fish as a food source that provides healthy, nutritious meals for many at local and global scales.

FINANCES

People recognize the importance of economic impact or, as the old adage goes, money talks and employment walks. First-sale value of global capture fisheries production and aquaculture is approximately US$93.9 billion and US$98.4 billion, respectively, and US$192.3 billion, collectively (FAO 2010). Numbers that large can seem intangible, but the first-sale of value of fisheries basically equates to one-seventh of the U.S. Gross Domestic Product.

More than strict monetary value, fisheries are significant sources of employment, income, and livelihood. Globally, 44.9 million people are directly engaged in capture fisheries or in aquaculture (FAO 2010). So, fisheries employ over 20 times more people than Walmart, the world's largest private employer. Taking families and dependents into account, fisheries are an important source of income and livelihood for 8% of the world's population, around 540 million people (FAO 2010). And, these are just minimum estimates. These Food and Agriculture Organization of the United Nations (FAO) statistics are very likely a gross underestimate of their full value because obtaining accurate capture and employment statistics on small-scale fisheries, the bulk of the world's fisheries, is difficult as they are highly dispersed and underreported (Cochrane et al. 2011).

FUN

Fish, lest we forget, also provide fun. Recreational fishers, snorkelers, SCUBA divers, and hobby aquarists seek enjoyment and relaxation through interacting with fish and their habitats. Though we cannot over-emphasize the value of these experiences to the individuals who find fish fun, the financial value of recreation can be understood even by those choosing not to engage in these types of activities. In 2011, for example, American anglers spent $41.8 billion in support of fishing activities (e.g., trips, equipment, licenses; USFWS 2012). Even those who have never picked up a fishing rod or visited an aquarium can appreciate the employment and economic stimulus generated by recreational fishing and fish watching.

Fish are important components of most human systems. While some cultural values, like recreation and tourism, can be translated into economic impact, other religious, spiritual, or artistic values are more difficult to assess economically. Nonetheless, fish are symbolized in every major world religion and the natural beauty of aquatic ecosystems is commonly evoked in art.

FUNCTION

Without question, fishes are the most diverse, numerous group of vertebrates on the planet. The estimated 27,977 species of fishes make up more than half of the approximate 54,711 recognized living vertebrate species (Nelson 2006) and occupy almost all major aquatic habitats (Helfman et al. 2009). In this role, fishes are a particularly important taxa for biodiversity conservation and resilience of ecosystems to change (Naeem 2012). As such, they often serve as symbols of the health and integrity of their habitats. They are, for all practical purposes, the aquatic version of "canaries in a coal mine." Fish are critical links in aquatic systems – indicators of ecosystem health and a litmus test of what the potential impacts could be for humans.

For people who fish, eat fish, or recreate in aquatic environments, the value of fish and fisheries is an easy sell. They use and appreciate the resource and want to ensure that fish will be around for them and future generations to use. But, demonstrating the value of fish to those who have no direct contact with them can be daunting, especially when negotiating tradeoffs for water security, agriculture, power generation, and other sectoral interests. As a whole, we, as professionals can be better communicators. We need to be cognizant that others may not share our passion for fish and we must provide them with a clear rationale of why fish and their habitats should be important to them: Food, Finances, Fun, and Function. Our future and that of fishes depend on us to do just that – make fish meaningful and important to all!

Fast Stats

Food

- 3.0 billion people (>40% of global population) depend directly on fish as an important source of protein.

Finances

- 540 million people (8% of global population) depend upon fishery industries for livelihood and income.

Fun

- Anglers in the United States spend over $40 billion in support of fishing activities annually.

Function

- Fishes comprise more than half of all vertebrate species and occupy all major aquatic habitats.

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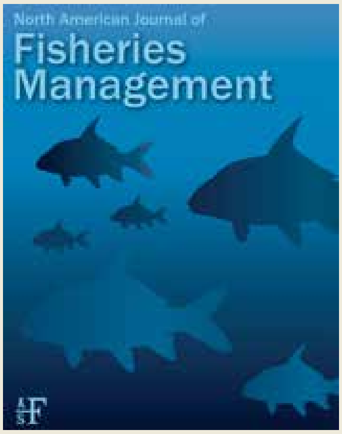
North American Journal of Fisheries Management, Volume 32, Number 6, December 2012



[Management Brief] A Prototype Splitter Apparatus for Dividing Large Catches of Small Fish. *Martin A. Stapanian and William H. Edwards. 32: 1033–1038.*

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registration fees to compensate the instructor and pay for the technology required to deliver the course effectively and add some funds to the AFS coffers.

No doubt, what I have prescribed for the Special Committee on Educational Requirements and the Continuing Education Committee is a lot of work for a set of volunteers and will likely take several years to accomplish. The tasks should probably become a matter of routine for the AFS, undertaken every 5–10 years to ensure that students and career professionals being trained in fisheries-related disciplines have the right educational foundation for meeting the challenges that lie ahead.

CALENDAR
Fisheries Events

To submit upcoming events for inclusion on the AFS web site calendar, send event name, dates, city, state/province, web address, and contact information to sgilbertfox@fisheries.org.

(If space is available, events will also be printed in Fisheries magazine.)

More events listed at www.fisheries.org

DATE	EVENT	LOCATION	WEBSITE
February 5–7, 2013	32nd International Kokanee Workshop	Fort Collins, CO	Jesse Lepak at Jesse.Lepak@state.co.us
February 7–8, 2013	Winter Fisheries Training for Acoustic Tag & Hydroacoustic Assessments	Seattle, WA	www.HTIsonar.com/at_short_course.htm
February 14–15, 2013	Using Hydroacoustics for Fisheries Assessment		www.HTIsonar.com/at_short_course.htm
February 21–25, 2013	AFS Fish Culture Section Mid-Year Business Meeting	Nashville, TN	www.was.org/WasMeetings/meetings/Default.aspx?code=AQ2013
February 21–25, 2013	AFS Aquaculture 2013	Nashville, TN	www.was.org/WasMeetings/meetings/Default.aspx?code=AQ2013
March 13–16, 2013	31st Annual Salmonid Restoration Conference	Fortuna, CA	http://www.calsalmon.org/salmonid-restoration-conference/31st-annual-salmonid-restoration-conference
March 26–29, 2013	Responses of Arctic Marine Ecosystems to Climate Change Symposium	Anchorage, AK	seagrant.uaf.edu/conferences/2013/wakefield-arctic-ecosystems/index.php
April 8–12, 2013	7th International Fisheries Observer and Monitoring Conference (7th IFOMC)	Viña del Mar, Chile	www.ifomc.com/
April 15–18, 2013	AFS Western Division of the AFS Annual Meeting	Boise, ID	www.idahoafs.org/meeting.php
April 25–26, 2013	NPAFC 3rd International Workshop on Migration and Survival Mechanisms of Juvenile Salmon and Steelhead in Ocean Ecosystems	Honolulu, HI	http://www.npafc.org/new/index.html
June 24–28, 2013	9th Indo-Pacific Fish Conference	Okinawa, Japan	http://www.fish-isj.jp/9ipfc
July 14–20, 2013	2nd International Conference on Fish Telemetry	Grahamstown, South Africa	Contact: Dr. Paul Cowley at tagfish@gmail.com
August 3–7, 2014	International Congress on the Biology of Fish	Edinburgh, United Kingdom	http://icbf2014.sls.hw.ac.uk

ANNOUNCEMENTS
January 2013 Jobs

Employers: to list a job opening on the AFS online job center submit a position description, job title, agency/company, city, state, responsibilities, qualifications, salary, closing date, and contact information (maximum 150 words) to jobs@fisheries.org. Online job announcements will be billed at $350 for 150 word increments. Please send billing information. Listings are free (150 words or less) for organizations with associate, official, and sustaining memberships, and for individual members, who are faculty members, hiring graduate assistants. if space is available, jobs may also be printed in *Fisheries* magazine, free of additional charge.

Modeler/Biometrician
Cramer Fish Sciences; Auburn, CA
Permanent

Salary: $5,265–$6,046 monthly, plus bonuses; excellent benefits

Closing: Until filled

Responsibilities: CFS seeks an individual with very strong quantitative and programming skills. Expertise in developing and analyzing individual/agent based models using NetLogo or other modeling platforms is highly desirable. Knowledge and experience with other statistical analyses, programming languages, and with ecology and resource management is a plus. Must be able to collaborate with biologists to develop simulation models and quantitative assessments for ecological data.

Qualifications: Ph.D. or M.S. with one or more years of experience with simulation modeling and statistics. Strong technical writing and advanced computer skills.Experience leading small to moderate sized projects. Highly-motivated, self-starter who can work independently and as part of a team. Speak and write English fluently.

Contact: E-mail cover letter and resume to below email Full job announcement at: www.fishsciences.net

Email: hr@fishsciences.net

Vice President of Conservation & Science
Monterey Bay Aquarium, CA
PhD

Salary: Competitive

Closing: Until filled

Responsibilities: The Vice President is responsible for overall leadership of the aquarium's Conservation and Science Division and is a member of the senior leadership team of the aquarium. The current activity areas in this division include Seafood Watch, ocean conservation policy and conservation research. For a full position description & details on how to apply please go to explorecompany.com.

Qualifications: Strong scientific background is required, particularly in the areas of ecology, marine biology, or conservation science. Ph.D. in Ecology, Biology, Natural Resources, Environmental Science or a closely related field desirable.

Email: resumes@explorecompany.com

Link: http://www.montereybayaquarium.org

Journal Editor
AFS, Bethesda, MD
Professional

Salary: Editors receive an honorarium, and support to attend the AFS Annual Meeting.

Closing: Until filled

Responsibilities: : AFS Seeks Journal Editor

The American Fisheries Society (AFS) seeks a scientist with a broad perspective on fisheries to serve as editor of North American Journal of Fisheries Management (NAJFM). Editor must be committed to fast-paced deadlines, and would be appointed for a five-year renewable term which begins January 2013.

Duties include:

1. Deciding on the suitability of contributed papers, and advising authors on what would be required to make contributions publishable, using advice of associate editors and reviewers. Reviewing papers for scientific accuracy as well as for clarity, readability, and interest to the broad fisheries community;

2. Soliciting manuscripts to ensure broad coverage;

3. Setting editorial standards for NAJFM in keeping with the objectives of the publication in accordance with AFS policies, and guidance provided by the Publications Overview Committee and the NAJFM editorial board;

4. Making recommendations to enhance the vitality and prestige of the Journal.

Qualifications: This position requires marine and estuarine fisheries expertise.

Contact: To be considered, send a current curriculum vitae along with a letter of interest explaining why you want to be the Journal editor to below email alerner@fisheries.org. To nominate a highly qualified colleague, send a letter of recommendation to the same e-mail address.

Email: alerner@fisheries.org

Regional Program Manager
WA State Dept of Fish & Wildlife
Permanent

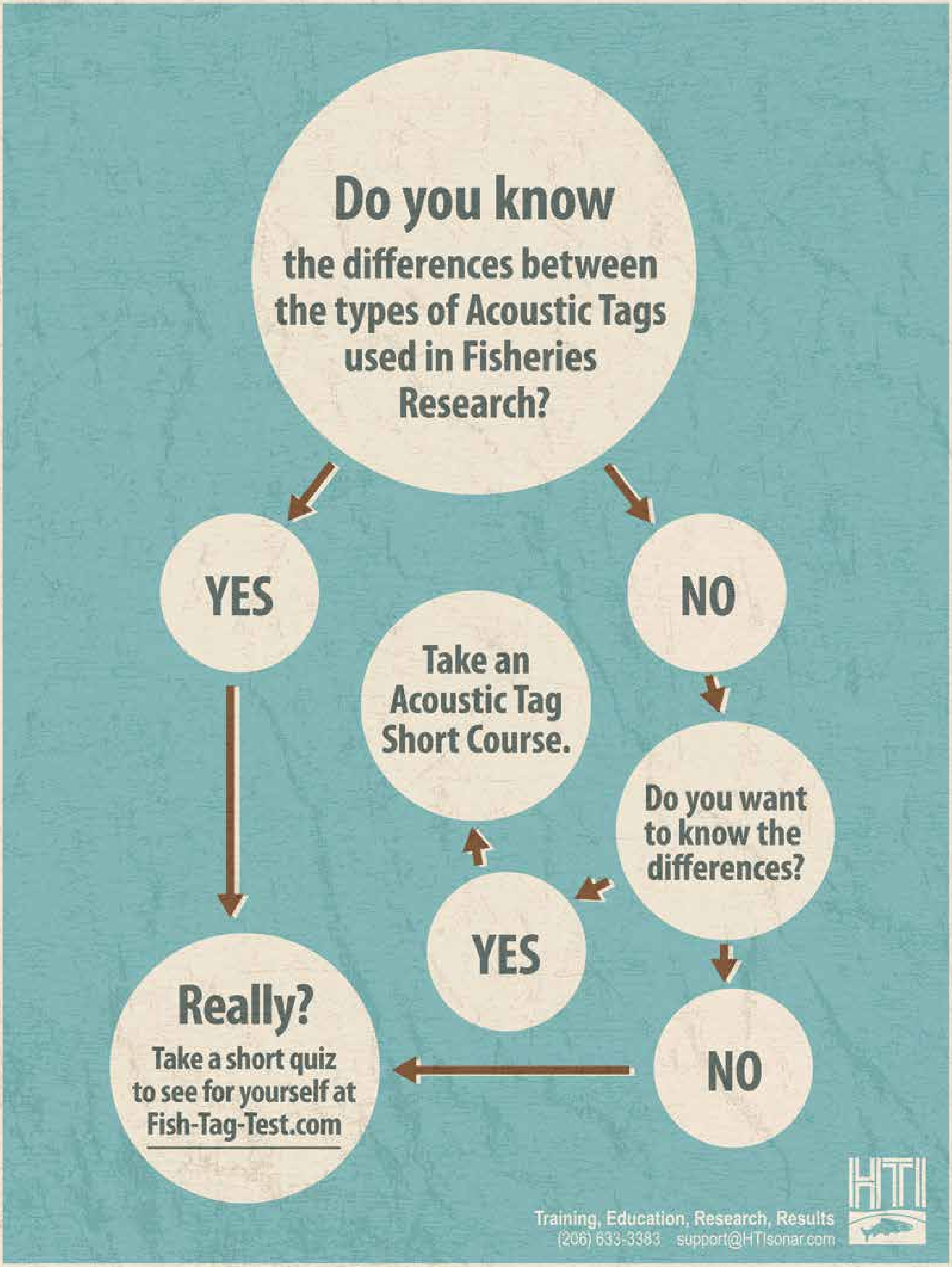
Salary: $5712.00–$7140.00

Closing: Until filled

Responsibilities: The official duty station is Vancouver, WA. This position reports to the Deputy Assistant Director for the Fish Program. This position leads, controls, and directs regional operations for the Fish Management and Hatcheries activities and project including: staff, budgets and programs in Region 5.

Contact: To Apply: For more information see the WDFW Employment Page for a complete listing at. This will explain job duties, minimum qualifications, competencies and desirable qualifications. If you have questions about this recruitment, you may contact Margaret Gordon, Recruitment Specialist at 360 902-2209.

Link: http://wdfw.wa.gov/employment/index.htm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The Costs of Fracking

The Price Tag of Dirty Drilling's Environmental Damage

ENVIRONMENT AMERICA
RESEARCH & POLICY CENTER

The Costs of Fracking

The Price Tag of Dirty Drilling's Environmental Damage

Environment America
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Tony Dutzik and Elizabeth Ridlington,
Frontier Group

John Rumpler,
Environment America
Research & Policy Center

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Infographic design: Jenna Leschuk

Executive Summary

Over the past decade, the oil and gas industry has fused two technologies—hydraulic fracturing and horizontal drilling—to unlock new supplies of fossil fuels in underground rock formations across the United States. "Fracking" has spread rapidly, leaving a trail of contaminated water, polluted air, and marred landscapes in its wake. In fact, a growing body of data indicates that fracking is an environmental and public health disaster in the making.

However, the true toll of fracking does not end there. Fracking's negative impacts on our environment and health come with heavy "dollars and cents" costs as well. In this report, we document those costs—ranging from cleaning up contaminated water to repairing ruined roads and beyond. Many of these costs are likely to be borne by the public, rather than the oil and gas industry. As with the damage done by previous extractive booms, the public may experience these costs for decades to come.

The case against fracking is compelling based on its damage to the environment and our health alone. To the extent that fracking does take place, the least the public can expect is for the oil and gas industry to be held accountable for the damage it causes. Such accountability must include up-front financial assurances sufficient to ensure that the harms caused by fracking are fully redressed.

Fracking damages the environment, threatens public health, and affects communities in ways that can impose a multitude of costs:

Drinking water contamination – Fracking brings with it the potential for spills, blowouts and well failures that contaminate groundwater supplies.

- Cleanup of drinking water contamination is so expensive that it is rarely even attempted. In Dimock, Pennsylvania, Cabot Oil & Gas reported having spent $109,000 on systems to remove methane from well water for 14 local households, while in Colorado, cleanup of an underground gas seep has been ongoing for eight years at a likely cost of hundreds of thousands of dollars, if not more.

- The provision of temporary replacement water supplies is also expensive. Cabot Oil & Gas reported having spent at least $193,000 on replacement water for homes with contaminated water in Dimock, Pennsylvania.

- Fracking can also pollute drinking water sources for major municipal systems, increasing water treatment costs. If fracking were to degrade the New York City watershed with sediment or other pollution, construction of a filtration plant would cost approximately $6 billion.

Health problems – Toxic substances in fracking fluid and wastewater—as well as air pollution from trucks, equipment and the wells themselves—have been linked to a variety of negative health effects.

- The National Institute of Occupational Safety and Health recently warned that workers may be at elevated risk of contracting the lung disease silicosis from inhalation of silica dust at fracking sites. Silicosis is one of a family of dust-induced occupational ailments that imposed $50 million medical care costs in the United States in 2007.

- Residents living near fracking sites have long suffered from a range of health problems, including headaches, eye irritation, respiratory problems and nausea—potentially imposing economic costs ranging from health care costs to workplace absenteeism and reduced productivity.

- Fracking and associated activities also produce pollution that contributes to the formation of ozone smog and particulate soot. Air pollution from gas drilling in Arkansas' Fayetteville Shale region imposed estimated public health costs of more than $10 million in 2008.

Natural resources impacts – Fracking converts rural and natural areas into industrial zones, replacing forest and farm land with well pads, roads, pipelines and other infrastructure, and damaging precious natural resources.

- The clearance of forest land in Pennsylvania for fracking could lead to increased delivery of nutrient pollution to the Chesapeake Bay, which already suffers from a vast nutrient-generated dead zone. The cost of reducing the same amount of pollution as could be generated by fracking would be approximately $1.5 million to $4 million per year.

- Gas operations in Wyoming have fragmented key habitat for mule deer and pronghorn, which are important draws for the state's $340 million hunting and wildlife watching industries. The mule deer population in one area undergoing extensive gas extraction dropped by 56 percent between 2001 and 2010.

- Fracking also produces methane pollution that contributes to global warming. Emissions of methane during well completion from each uncontrolled fracking well impose approximately $130,000 in social costs related to global warming.

Impacts on public infrastructure and services – Fracking strains infrastructure and public services and imposes cleanup costs that can fall on taxpayers.

- The truck traffic needed to deliver water to a single fracking well causes as much damage to local roads as nearly 3.5 million car trips. The state of Texas has approved $40 million in funding for road repairs in the Barnett Shale region, while

Pennsylvania estimated in 2010 that $265 million would be needed to repair damaged roads in the Marcellus Shale region.

- The need for vast amounts of water for fracking is helping to drive demand for new water infrastructure in arid regions of the country. Texas' official State Water Plan calls for the expenditure of $400 million on projects to support the mining sector over the next 50 years, with fracking projected to account for 42 percent of mining water use by 2020.

- The oil and gas industry has left thousands of orphaned wells from previous fossil fuel booms. Taxpayers may wind up on the hook for the considerable expense of plugging and reclaiming orphaned wells—Cabot Oil & Gas claims to have spent $730,000 per well to cap three shale gas wells in Pennsylvania.

- Fracking brings with it increased demands for public services. A 2011 survey of eight Pennsylvania counties found that 911 calls had increased in seven of them, with the number of calls increasing in one county by 49 percent over three years.

Broader economic impacts – Fracking can undercut the long-term economic prospects of areas where it takes place. A 2008 study found that Western counties that have relied on fossil fuel extraction are doing worse economically compared with peer communities and are less well-prepared for growth in the future.

- Fracking can affect the value of nearby homes. A 2010 study in Texas concluded that houses valued at more than $250,000 and within 1,000 feet of a well site saw their values decrease by 3 to 14 percent.

- Fracking has several negative impacts on farms, including the loss of livestock due to exposure to spills of fracking wastewater, increased difficulty in obtaining water supplies for farming, and potential conflicts with organic agriculture. In Pennsylvania, the five counties with the heaviest Marcellus Shale drilling activity saw an 18.5 percent reduction in milk production between 2007 and 2010.

As with previous fossil fuel booms that left long-term impacts on the environment, there is every reason to believe that the public will be stuck with the bill for many of the impacts of fracking.

Defining "Fracking"

In this report, when we refer to the impacts of "fracking," we include impacts resulting from all of the activities needed to bring a well into production using hydraulic fracturing, to operate that well, and to deliver the gas or oil produced from that well to market. The oil and gas industry often uses a more restrictive definition of "fracking" that includes only the actual moment in the extraction process when rock is fractured—a definition that obscures the broad changes to environmental, health and community conditions that result from the use of fracking in oil and gas extraction.

- Existing legal rules are inadequate to protect the public from the costs imposed by fracking. Current bonding requirements fail to assure that sufficient funds will be available for the proper closure and reclamation of well sites, and do nothing at all to ensure that money is available to fix other environmental problems or compensate victims. Further, weak bonding requirements fail to provide an adequate incentive for drillers to take steps to prevent pollution before it occurs.

- Current law also does little to protect against impacts that emerge over a long period of time, have diffuse impacts over a wide area, or affect health in ways that are difficult to prove with the high standard of certainty required in legal proceedings.

The environmental, health and community impacts of fracking are severe and unacceptable. Yet the dirty drilling practice continues at thousands of sites across the nation. Wherever fracking does occur, local, state and federal governments should at least:

- **Comprehensively restrict and regulate** fracking to reduce its environmental, health and community impacts as much as possible.

- Ensure **up-front financial accountability** by requiring oil and gas companies to post dramatically higher bonds that reflect the true costs of fracking.

Introduction

In Appalachia, more than 7,500 miles of streams are polluted with acid mine drainage—the legacy of coal mining. Many of those streams still run orange-colored and lifeless decades after mining ended. The ultimate cost of cleaning up acid mine drainage in Pennsylvania alone has been estimated at $5 billion.[1]

Texas has more than 7,800 orphaned oil and gas wells—wells that were never properly closed and whose owners, in many cases, no longer exist as functioning business entities.[2] These wells pose a continual threat of groundwater pollution and have cost the state of Texas more than $247 million to plug.[3]

In the western United States, uranium mining and milling have contaminated both water and land. The cost to taxpayers of cleaning up the uranium mills has been estimated at $2.3 billion, while the cost of cleaning up abandoned mines has been estimated at $14 million per mine.[4]

Over and over again, throughout American history, short-term resource extraction booms have left a dirty long-term legacy, imposing continuing costs on people and the environment years or decades after those who profited from the boom have left the scene.

Today, America is in the midst of a new resource extraction boom, one driven by a process colloquially known as "fracking." In just over a decade, fracking has spread across the country, unlocking vast supplies of previously inaccessible oil and gas from underground rock formations.

The costs of fracking—in environmental degradation, in illness, and in impacts on infrastructure and communities—are only just now beginning to be understood and tallied. It is also now becoming clear that the nation's current system of safeguards is incapable of protecting the public from having to shoulder those sizable costs in the years and decades to come.

The burdens imposed by fracking are significant, and the dangers posed to the environment and public health are great. If fracking is to continue, the least the American people should expect is for our laws to ensure that those who reap the benefits also bear its full costs.

The landscapes of Appalachia, Texas and the American West are living testaments to the need to hold industries accountable for cleaning up the damage they cause. As fracking unleashes yet another extractive boom, the time has come to ensure that this history does not repeat itself in the 21^{st} century.

Fracking: The Process and its Impacts

Over the past decade, the oil and gas industry has married two technologies—horizontal drilling and hydraulic fracturing—to create a potent new combination that is being used to tap fossil fuels locked in previously difficult-to-reach rock formations across the United States. This technology, known as high-volume horizontal hydraulic fracturing—or, colloquially, "fracking"—has broad implications for the environment and public health.

Defining "Fracking"

Public debates about fracking often descend into confusion and contradiction due to a lack of clarity about terms. To the oil and gas industry, which seeks to minimize the perceived impacts, "fracking" refers only to the actual moment in the extraction process where rock is fractured by pumping fluid at high pressure down the well bore. Limiting the definition of fracking in this way also allows the oil and gas industry to include its long history of using hydraulic fracturing in traditional, vertical wells—a process with fewer impacts than the technology being used in oil and gas fields today—to create a false narrative about the safety of fracking. It is only according to this carefully constructed definition that ExxonMobil CEO Rex Tillerson could say, as he did in a Congressional hearing in 2011, that "[t]here have been over a million wells hydraulically fractured in the history of the industry, and there is not one, not one, reported case of a freshwater aquifer having ever been contaminated from hydraulic fracturing."[5]

Just as only a small portion of an iceberg is visible above the water, only a small portion of the impacts of fracking are the direct result of fracturing rock. Each step in the process of extracting oil or gas from a fracked well has impacts on the environment, public health and communities. Thus, any reasonable assessment of fracking ***must*** include the full cycle of extraction operations before and after the moment where rock is cracked open with fluid under high pressure.

In this report, when we refer to the impacts of "fracking," we include impacts resulting from all of the activities needed to bring a well into production using hy-

Fracking imposes a range of environmental, health and community impacts. Above, a fracking well site is built in a forested area of Wetzel County, W.Va. Credit: Robert Donnan

draulic fracturing, to operate that well, and to deliver the gas or oil extracted from that well to market.

The Fracking Process

Fracking is used to unlock gas or oil trapped in underground rock formations, allowing it to flow to the surface, where it can be captured and delivered to market. Fracking combines hydraulic fracturing, which uses a high-pressure mixture of water, sand and chemicals to break up underground rock formations, with horizontal drilling, which enables drillers to fracture large amounts of rock from a single well.

The combination of hydraulic fracturing with horizontal drilling has magnified the environmental impacts of oil and gas extraction. Whereas traditional, low-volume hydraulic fracturing used tens of thousands of gallons of water per well, today's high-volume hydraulic fracturing operations use millions of gallons of water, along with a different combination of sand and chemical additives, to extract gas or oil.

A vast amount of activity—much of it with impacts on the environment and nearby communities—is necessary to bring a fracking well into production and to deliver the gas extracted from that well to market. Among those steps are the following:

Well Site Preparation and Road Construction

Before drilling can begin, several acres of land must be cleared of vegetation and leveled to accommodate drilling equipment, gas collection and processing equipment, and vehicles. Additional land must be cleared for roads to the well site, as well as for any pipelines needed to deliver gas to market.

Materials Assembly

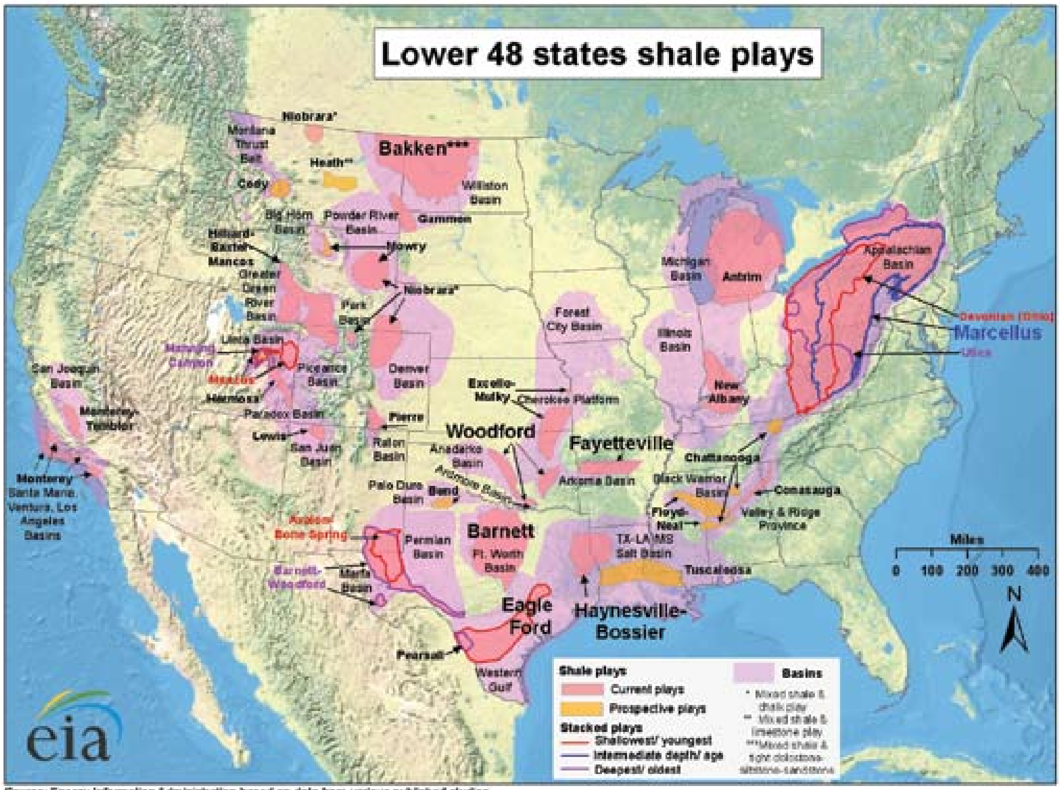
Hydraulic fracturing requires massive amounts of water, sand and chemicals—all of which must be obtained and delivered to the well site. Water for fracking comes either from surface waterways, groundwater or recycled wastewater from previous fracking activities, with millions of gallons of water required for each well. The special grade of sand used in fracking must be extracted from the ground—often from silica mines in the upper Midwest—and transported to the well site. Water, sand and other materials must be carried to well sites in trucks, tearing up local roads, creating congestion, and producing local level air pollution.

Drilling and Hydraulic Fracturing

Once the necessary machinery and materials are assembled at the drilling site, drilling can begin. The well is drilled to the depth of the formation that is being targeted. In horizontally drilled wells, the well bore is turned roughly 90 degrees to extend along the length of the formation. Steel "casing" pipes are inserted to stabilize and contain the well, and the casing is cemented into place. A mix of water, sand and chemicals is then injected at high pressure—the pressure causes the rock formation to crack, with the sand propping open the gaps in the rock. Some of the injected water then flows back out of the well when the pressure is released ("flowback" water), followed by gas and water from the formation ("produced water").

Equipment is put in place in preparation for hydraulic fracturing at a well site in Troy, Pa. In hydraulic fracturing, a combination of water, sand and chemicals is injected at high pressure to fracture oil or gas-bearing rock formations deep underground. Credit: New York Department of Environmental Conservation

Figure 1. Shale Gas and Oil Plays[6]



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Gas Processing and Delivery

As natural gas flows from the fracked well, it must be collected, purified and compressed for injection into pipelines and delivery to market.

Wastewater Management and Disposal

Flowback and produced water must be collected and disposed of safely. Wastewater from fracking wells is often stored onsite temporarily in retention ponds or tanks. From there, the fluid may be disposed of in an underground injection well or an industrial wastewater treatment plant, or it may be treated and re-used in another fracking job.

Plugging and Reclamation

To prevent future damage to the environment and drinking water supplies, wells must be properly plugged and the land around them restored to something approaching its original vegetated condition. This involves plugging the well with cement, removing all unnecessary structures from the well pad, and replanting the area.

Fracking and the New Gas/Oil Rush

From its beginnings in the Barnett Shale region of Texas at the turn of the 21st century, the use of fracking has spread across the United States with breathtaking speed. A decade later, the combination of high-volume hydraulic fracturing with horizontal drilling has been used in thousands of oil and gas wells across the country—despite persistent questions about the impact of the technology and supporting activities on the environment, public health and communities.

Roughy half of U.S. states, stretching from New York to California, sit atop shale or other rock formations with the potential to produce oil or gas using fracking. As fracking has made oil and gas extraction viable in more of these formations, it is bringing drilling closer to greater numbers of people as well as precious natural resources.

- Between 2003 and 2010, more than 11,000 wells were drilled in the Fort Worth basin of Texas' Barnett Shale formation.[7] The Barnett Shale underlies one of the most populous regions of the state—the Dallas-Fort Worth Metroplex—and drilling has taken place in urban and suburban neighborhoods of the region.

- In Pennsylvania's Marcellus Shale, more than 6,300 shale gas wells have been drilled since 2000; permits have been issued that would allow for more than 2,400 additional wells to be drilled.[8] A 2011 analysis by PennEnvironment Research & Policy Center found that 104 day care centers and 14 schools in Pennsylvania were located within a mile of a shale gas well; that figure is certainly higher today.[9]

- In Colorado, fracking has taken off in the oil-producing Niobrara Shale formation. Weld County, Colorado, located just north of Denver and just east of Fort Collins, has seen the permitting of more than 1,300 horizontal wells since the beginning of 2010.[10]

Oil and gas companies are aggressively seeking to expand fracking to places where more people live (including the city of Dallas) and to treasured natural areas (including the Delaware River Basin, which provides drinking water for 15 million people). Wherever this new gas rush is allowed, it will impose significant impacts on the environment, public health and communities. To add insult to injury, these impacts also come with heavy price tags that will all too often be borne by individual residents and their communities. The following section of this report provides a breakdown of fracking impacts along with examples of the real-life costs already being imposed on America's environment and our communities.

The Costs of Fracking

A great deal of public attention has been focused on the immediate impacts of fracking on the environment, public health and communities. Images of flaming water from faucets, stories of sickened families, and incidents of blowouts, spills and other mishaps have dramatically illustrated the threats posed by fracking.

Less dramatic, but just as important, are the long-term implications of fracking—including the economic burdens imposed on individuals and communities. In this paper, we outline the many economic costs imposed by fracking and show that, absent greatly enhanced mechanisms of financial assurance, individuals, communities and states will be left to bear many of those costs.

Residents of Dimock, Pennsylvania, are among those who have reported drinking water contamination in the wake of nearby fracking activity. Here, discolored water from local wells illustrates the change in water quality following fracking. Photo: Hudson Riverkeeper

Drinking Water Contamination

Fracking can pollute both groundwater and surface waterways such as rivers, lakes and streams. In rural areas, where the bulk of fracking takes place, residents may rely on groundwater for household and agricultural use. Alternative sources of water—such as municipal water supplies—may be unavailable or prohibitively expensive.

Fracking has polluted drinking water sources in a variety of ways.

- Spills and well blowouts have released fracking chemicals and flowback or produced water to groundwater and surface water. In Colorado and New Mexico, an estimated 1.2 to 1.8 percent of all gas drilling projects result in groundwater contamination.[11]

- Waste pits containing flowback and produced water have frequently failed. In New Mexico, substances from oil and gas pits have contaminated groundwater at least 421 times.[12]

- Faulty well construction has caused methane and other substances to find their way into groundwater.[13]

Recent studies have suggested that fracking may also pose a longer-term threat of groundwater contamination. One study used computer modeling to conclude that natural faults and fractures in the Marcellus Shale region could accelerate the movement of fracking chemicals—possibly bringing these contaminants into contact with groundwater in a matter of years.[14] In addition, a recent study by researchers at Duke University found evidence for the existence of underground pathways between the deep underground formations tapped by Marcellus Shale fracking and groundwater supplies closer to the surface.[15] The potential for longer-term groundwater contamination from fracking is particularly concerning, as it raises the possibility that contamination will become apparent only long after the drillers responsible have left the scene.

Among the costs that result from drinking water contamination are the following:

Groundwater Cleanup

Groundwater is a precious and often limited natural resource. Once contaminated, it can take years, decades or even centuries for groundwater sources to clean themselves naturally.[16] As a result, the oil and gas industry must be held responsible for restoring groundwater supplies to their natural condition.

Methane contamination of well water poses a risk of explosion and is often addressed by removing it from water at the point of use. In Dimock, Pennsylvania, Cabot Oil & Gas reported having spent $109,000 on methane removal systems for 14 local households in the wake of drilling-related methane contamination of local groundwater supplies. In addition, the company spent $10,000 on new or extended vent stacks to prevent the build-up of methane gas in residents' homes.[17] Such measures do not remove methane from groundwater supplies, but merely eliminate the immediate threat to residents' homes.

"In Dimock, Pennsylvania, Cabot Oil & Gas reported having spent $109,000 on methane removal systems for 14 households."

Removing other toxic contaminants from groundwater is so costly that it it rarely attempted, with costs of hundreds of thousands of dollars or more.

In 2004, improper cementing of a fracking well in Garfield County, Colorado, caused natural gas to vent for 55 days into a fault terminating in a surface waterway, West Divide Creek.[18] In response to the leak, the company responsible for drilling the well, Encana, engaged in regular testing of nearby wells and installed equipment that injects air into the groundwater, enabling chemical contaminants in the water to become volatile and be removed from the water, using a process known as air sparging. These activities began in 2004 and were still ongoing as of mid-2012.[19]

The cost of groundwater remediation in the Garfield County case is unknown, but likely runs into the hundreds of thousands of dollars, if not more. A 2004 Environmental Protection Agency (EPA) document, referring to the work of a federal roundtable on environmental cleanup technologies, estimated the cost of air sparging at $150,000 to $350,000 per acre.[20] Adjusting for inflation, and assuming that the extent of the seep was correctly estimated by Encana at 1.3 acres, one could estimate the cost of the sparging operation in 2012 dollars at $248,000 to $579,000.[21] In addition, as of May 2012, Encana and its contractors had collected more than 1,300 water samples since the seep began.[22] Again, the cost of this sampling and testing is unknown, but could be conservatively estimated to be in the tens of thousands of dollars. Cabot Oil & Gas, for example, incurred $700,000 in water testing expenses in the wake of concerns about groundwater contamination from a fracking well in Dimock, Pennsylvania.[23]

The Colorado example shows that the process of cleaning up contaminated groundwater can take years to complete, underscoring the need for protections to ensure that drillers have the financial wherewithal to fulfill their obligations to clean up pollution.

Water Replacement

As noted above, the process of cleaning up contaminated groundwater can take years. In the meantime, residents must be provided with clean, temporary sources of drinking water.

"Cabot Oil & Gas provided at least $193,000 worth of water to homes affected by contamination."

The Colorado and Pennsylvania examples above demonstrate the high cost of supplying replacement water to households dependent on contaminated wells. In Colorado, Encana offered "complete water systems and potable water delivery" to homes within a two-mile area of the West Divide Creek gas seep, at an estimated cost of $350,000.[24] These deliveries continued into 2006. In Pennsylvania, Cabot Oil & Gas provided at least $193,000 worth of water to homes affected by contamination there.[25] A permanent solution to water issues in Dimock—the extension of municipal water to the neighborhood—was estimated to cost $11.8 million.[26]

Water Treatment Costs Due to Surface Water Contamination

Fracking and related activities may reduce the quality of rivers and streams to the point where municipalities must invest in additional water treatment in order to make water safe to drink.

"Should gas drilling require drinking water to undergo additional treatment, New York would be required to build one of the world's largest filtration plants at an estimated cost of $6 billion."

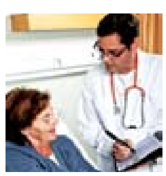
The most significant impacts of fracking on rivers and streams used for drinking water come not from individual spills, blowouts or other accidents, but rather from the effects of fracking many wells in a given area at the same time. Widespread fracking can damage waterways through water withdrawals from river basins, the dumping of fracking wastewater into rivers, or increased sedimentation resulting from land clearance for well pads, pipelines and other natural gas infrastructure.

Damage from widespread fracking may require water utilities to invest in expensive additional treatment. New York City's water supply, for example, comes from upstate New York watersheds that are sufficiently pristine that water filtration is not required. Should gas drilling—or any other polluting activity—require additional treatment, New York would be required to build one

The disposal of fracking wastewater in open pits contributes to air pollution, while leakage from improperly lined pits has contaminated groundwater and surface water. Chemicals present in fracking wastewater have been linked to serious health problems, including cancer. Credit: Mark Schmerling

of the world's largest water filtration plants. New York has already had to take this step for one major source of drinking water, spending $3 billion to build a filtration plant for the part of the watershed east of the Hudson River.[27] The cost of doing the same for areas west of the Hudson, which sit atop the Marcellus Shale formation, was estimated in 2000 to be as much as $6 billion.[28]

Health Problems



Fracking produces pollution that affects the health of workers, nearby residents and even people living far away. Toxic substances in fracking chemicals and produced water, as well as pollution from trucks and compressor stations, have been linked to a variety of negative health effects. Chemical components of fracking fluids, for example, have been linked to cancer, endocrine disruption, and neurological and immune system problems.[29]

The legal system often offers little relief for those whose health is impacted by chemically tainted air or water. In order to prevail in court, an individual affected by exposure to toxic chemicals must prove that he or she has been exposed to a specific toxic chemical linked to the health effects that they are experiencing *and* that the exposure was caused by the defendant (as opposed to the many other sources of possible exposure to toxic chemicals that most people experience every day).[30] Meeting that high legal standard of proof is costly—usually requiring extensive medical and environmental testing and expert testimony—and difficult, given corporate attorneys' track record of exploiting gaps in scientific knowledge to cast doubt on claims of harm from toxic chemical exposures. As a result, many citizens whose health has been affected by fracking may be discouraged from taking their complaints to court.

Individuals and taxpayers, therefore—rather than polluters—may bear much of the financial burden for health costs resulting from fracking.

Nearby Residents Getting Sick

Emissions from fracking wellsites contain numerous substances that make people sick.

In Texas, monitoring by the Texas Department of Environmental Quality detected levels of benzene—a known cancer-causing chemical—in the air that were high enough to cause immediate human health concern at two sites in the Barnett Shale region, and at levels that pose long-term health concern at an additional 19 sites. Several chemicals were also found at levels that can cause foul odors.[31] Less extensive testing conducted by the Pennsylvania Department of Environmental Protection detected components of natural gas, particularly methane, in the air near Marcellus Shale drilling operations.[32] Air monitoring in Arkansas has also found elevated levels of volatile organic compounds (VOCs)—some of which are also hazardous air pollutants—at the perimeter of hydraulic fracturing sites.[33]

"Residents living near fracking sites have long suffered from a range of health problems, including headaches, eye irritation, respiratory problems and nausea—imposing economic costs ranging from health care costs to workplace absenteeism and reduced productivity."

Residents living near fracking sites have long suffered from a range of health problems, including headaches, eye irritation, respiratory problems and nausea.[34] In western Pennsylvania, for example, residents living near one fracking well site have complained of rashes, blisters and other health effects that they attribute to a wastewater impoundment.[35] An investigation by the investigative journalism website ProPublica uncovered numerous similar reports of illness in western states.[36]

A recent study by researchers at the Colorado School of Public Health found that residents living within a half-mile of natural gas wells in one area of Colorado were exposed to air pollutants that increased their risk of illness.[37] The report noted that "health effects, such as headaches and throat and eye irritation reported by residents during well completion activities occurring in Garfield County, are consistent with known health effects of many of the hydrocarbons evaluated in this analysis."[38]

These health impacts are unacceptable regardless of the economic cost. But they also have significant economic impacts, including:

- Health care costs, including inpatient, outpatient and prescription drug costs;
- Workplace absenteeism;
- "Presenteeism," or reduced productivity at work.[39]

Major health problems such as cancer are obviously costly. The average case of cancer in the United States in 2003 imposed costs in treatment and lost productivity of approximately $30,000.[40]

The economic impacts of less severe problems such as headaches and respiratory symptoms can also add up quickly. Each day of reduced activity costs the economy roughly $50 while a missed day of work costs approximately $105.[41] The economic value to individuals of avoiding one exposure to hydrocarbon odors per week is approximately $26 to $36 per household.[42] As fracking continues to spread, particularly in areas close to population centers, the number of residents affected by these health problems—already substantial—is likely to increase.

Worker Injury, Illness, and Death

Fracking is dangerous business for workers. Nationally, oil and gas workers are seven times more likely to die on the job than other workers, with traffic accidents, death from falling objects, and explosions the leading causes of death. Between 2003 and 2008, 648 oil and gas workers nationwide died from on-the-job injuries.[43] Workers at fracking well sites are vulnerable to many of these same dangers, as well as one that is specific to fracking: inhalation of silica sand.

Silica sand is used to prop open the cracks formed in underground rock formations during fracking. As silica is moved from trucks to the well site, silica dust can become airborne. Without adequate protection, workers who breathe in silica dust can develop an elevated risk of contracting silicosis, which causes swelling in the lungs, leading to the development of chronic

"The National Institute of Occupational Safety and Health recently warned that workers at fracking sites may be at risk of contracting the lung disease silicosis from inhalation of silica dust. Silicosis is one of a family of dust-induced occupational ailments that imposed $50 million in medical care costs in 2007."

Fracking can be a dangerous business for workers. The National Institute for Occupational Safety and Health recently found dangerous levels of airborne silica at fracking sites in several states, while workers also risk injury from traffic accidents, falling objects, explosions and other hazards. Workers, their families and the public often bear much of the costs of workplace illness and injury. Credit: Mark Schmerling cough and breathing difficulty.[44] Silica exposure can also cause lung cancer.[45]

A recent investigation by the National Institute for Occupational Safety and Health (NIOSH) found that workers at some fracking sites may be at risk of lung disease as a result of inhaling silica dust. The NIOSH investigation reviewed 116 air samples at 11 fracking sites in Arkansas, Colorado, North Dakota, Pennsylvania and Texas. Nearly half (47 percent) of the samples had levels of silica that exceeded the Occupational Safety and Health Administration's (OSHA) legal limit for workplace exposure, while 78 percent exceeded OSHA's recommended limits. Nearly one out of 10 (9%) of the samples exceeded the legal limit for silica by a factor of 10, exceeding the threshold at which half-face respirators can effectively protect workers.[46]

Silicosis is one of a family of dust-induced occupational ailments (including asbestosis and black lung disease) that have long threatened the health of industrial workers. A recent study estimated that this category of occupational disease imposed costs in medical care alone of $50 million in 2007.[47]

Workers, their families and taxpayers are often forced to pick up much of the cost of workplace illnesses and injuries. A 2012 study by researchers at the University of California, Davis, estimated that workers compensation insurance covers only about 20 percent of the total costs of workplace illness and injury, with government programs such as Medicaid and Medicare, as well as workers and their families, bearing much of the burden in health care costs and lost productivity.[48]

Air Pollution Far from the Wellhead

Air pollution from fracking also threatens the health of people living far from the wellhead—especially children, the elderly and those with respiratory disease.

Fracking produces a variety of pollutants that contribute to regional air pollution problems. VOCs in natural gas formations contribute to the formation of ozone "smog," which reduces lung function among healthy people, triggers asthma attacks, and has been linked to increases in school absences, hospital visits and premature death.[49] Some VOCs are also considered "hazardous air pollutants," which have been linked to cancer and other serious health effects. Emissions from trucks carrying water and materials to well sites, as well as from compressor stations and other fossil fuel-fired machinery, also contribute to the formation of smog and soot that threatens public health.

"Air pollution from drilling in Arkansas' Fayetteville Shale in 2008 likely imposed public health costs greater than $10 million in 2008."

Fracking is a significant source of air pollution in areas experiencing large amounts of drilling. A 2009 study in five Dallas-Fort Worth-area counties experiencing heavy Barnett Shale drilling activity found that oil and gas production was a larger source of smog-forming emissions than cars and trucks.[50] Completion of a single uncontrolled natural gas well produces approximately 22.7 tons of volatile organic compounds (VOC) per well—equivalent to the annual VOC emissions of about 7,000 cars—as well as 1.7 tons of hazardous air pollutants and approximately 156 tons of methane, which contributes to global warming.[51]

Well operations, storage of natural gas liquids, and other activities related to fracking add to the pollution toll, playing a significant part in regional air pollution problems. In Arkansas, for example, gas production in the Fayetteville Shale region was estimated to be responsible for

2.6 percent of the state's total emissions of nitrogen oxides (NO_x).[52] An analysis conducted for New York State's revised draft environmental impact statement on Marcellus Shale drilling posited that, in a worst case scenario of widespread drilling and lax emission controls, shale gas production could add 3.7 percent to state NO_x emissions and 1.3 percent to statewide VOC emissions compared with 2002 emissions levels.[53]

The public health costs of pollution from fracking are significant. The financial impact of ozone smog on public health has been estimated at $1,648 per ton of NO_x and VOCs.[54] Applying those costs to emissions in five counties of the Dallas-Fort Worth region with significant Barnett Shale drilling, the average public health cost of those emissions would be more than $270,000 *per day* during the summer ozone season.[55] In Arkansas, the nearly 6,000 tons of NO_x and VOCs emitted in 2008 would impose an annual public health cost of roughly $9.8 million.[56]

Various aspects of fracking also create particulate—or soot—pollution. A 2004 EPA regulatory impact analysis for new standards for stationary internal combustion engines often used on natural gas pipelines and in oil and gas production, for example, estimated the benefit of reducing one ton of particulates under 10 microns in diameter (PM_{10}) at $8,028 per ton.[57] Using this figure, the economic benefit of eliminating PM_{10} emissions from Arkansas' Fayetteville Shale would be roughly $5.4 million per year.

Air pollution from drilling in Arkansas' Fayetteville Shale in 2008, therefore, likely imposed public health costs greater than $10 million in 2008, with additional, unquantified costs imposed in the form of lost agricultural production and lower visibility.

Damage to Natural Resources

Fracking threatens valuable natural resources all across the country. Fracking converts rural and natural areas into industrialized zones, with forests and agricultural land replaced by well pads, roads, pipelines and natural gas infrastructure. The effects of this development are more than just aesthetic, as economists have increasingly come to recognize the value of the services that natural systems provide to people and the economy.

Threats to Our Rivers and Streams

Damage to aquatic ecosystems has a direct, negative impact on the economy. The loss of a recreational or commercial fishery due to spills, excessive withdrawals of water, or changes in water quality caused by the cumulative effects of fracking in an area can have devastating impacts on local businesses.

"The clearance of forest land in Pennsylvania for fracking could lead to increased delivery of nutrient pollution to the Chesapeake Bay, which suffers from a nutrient-generated dead zone. The cost of reducing an amount of pollution equivalent to that produced by fracking would be approximately $1.5 million to $4 million per year."

In Pennsylvania, for example, fishing had an estimated economic impact of $1.6 billion in 2001.[58] Allocating that impact to the roughly 13.4 million fishing trips taken in Pennsylvania each year (as of the late 1990s) would result in an estimated impact of $119 per trip.[59]

The Monongahela River, shown here at Rices Landing, Pa., has been affected by discharges of fracking wastewater and by water withdrawals for fracking. A 2011 Army Corps of Engineers report concluded that "the quantity of water withdrawn from streams [in the Monongahela watershed] is largely unregulated and is beginning to show negative consequences." Credit: Jonathan Dawson

Spills, blowouts and other accidents related to fracking have caused numerous fish kills in Pennsylvania. In 2009, a pipe containing freshwater and flowback water ruptured in Washington County, Pennsylvania, triggering a fish kill in a tributary of Brush Run, which is part of a high-quality watershed.[60] That same year, in the same county, another pipe rupture at a well drilled in a public park killed fish and other aquatic life along a three-quarter-mile length of a local stream.[61]

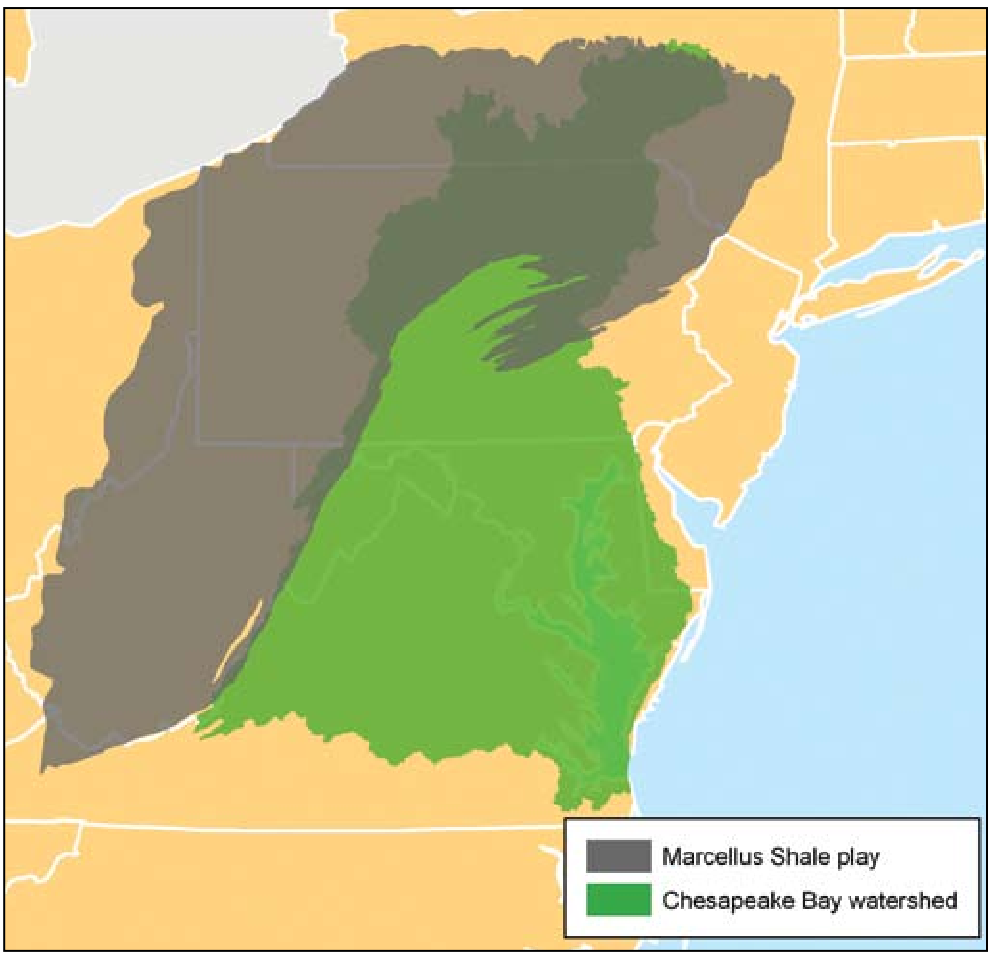
The clearing of land for well pads, roads and pipelines can increase sedimentation of nearby waterways and degrade the ability of natural landscapes to retain nutrients. A recent preliminary study by the Academy of Natural Sciences of Drexel University found an association between increased density of natural gas drilling activity and degradation of ecologically important headwaters streams.[62]

Excessive water withdrawals also play havoc with the ecology of rivers and streams. In Pennsylvania, water has been illegally withdrawn for fracking numerous times, to the extent of streams being sucked dry. Two streams in southwestern Pennsylvania—Sugarcamp Run and Cross Creek—were reportedly drained for water withdrawals, triggering fish kills.[63]

Water withdrawals also concentrate pollutants, reducing water quality. A 2011 U.S. Army Corps of Engineers study of the Monongahela River basin of Pennsylvania and West Virginia concluded that, "The quantity of water withdrawn from streams is largely unregulated and is beginning to show negative consequences."[64] The Corps report noted that water is increasingly being diverted from the relatively clean streams that flow into Corps-maintained reservoirs, limiting the ability of the Corps to release clean water to help dilute pollution during low-flow periods.[65] It described the water supply in the Monongahela basin as "fully tapped."[66]

On a broader scale, the clearance of forested land for well pads, roads and pipelines reduces the ability of the land to prevent pollution from running off into rivers and streams. Among the waterways most affected by runoff pollution is the Chesapeake Bay, where excessive runoff of nutrients such as nitrogen and phosphorus causes the formation of a "dead zone" that spans as much as a third of the bay in the summertime.[67] The Chesapeake Bay watershed overlaps with some of the most intensive Marcellus Shale fracking activity, creating the potential for additional pollution that will make the bay's pollution reduction goals more difficult to meet.

A rapid expansion of shale gas drilling could contribute an additional 30,000 to 80,000 pounds per year of nitrogen and 15,000 to 40,000 pounds per year of phosphorus to the bay, depending on the amount of forest lost.[68] While this additional pollution represents a small fraction of the total pollution currently reaching the bay, it is pollution that would need to be offset by reductions elsewhere in order to ensure that the Chesapeake Bay meets pol-



Many waterways in the Marcellus Shale region drain into the Chesapeake Bay. The loss of forests to natural gas development could add to pollution levels in the bay, threatening the success of state and federal efforts to prevent the "dead zone" that affects the bay each summer. Sources: Skytruth, U.S. Energy Information Administration, Chesapeake Bay Program

Pronghorn antelope are among the species that have been affected by intense natural gas development in Wyoming. Credit: Christian Dionne

lution reduction targets designed to restore the bay to health.[69] Based on an estimate of the cost per pound of nitrogen reductions from a recent analysis of potential nutrient trading options in the Chesapeake Bay watershed,[70] the cost of reducing nitrogen pollution elsewhere to compensate for the increase from natural gas development would run to approximately $1.5 million to $4 million per year.

Habitat Loss and Fragmentation

Extensive natural gas development requires the construction of a vast infrastructure of roads, well pads and pipelines, often through remote and previously undisturbed wild lands. The disruption and fragmentation of natural habitat can put species at risk.

Hunting and other forms of outdoor recreation are economic mainstays in several states in which fracking is taking place. In Wyoming, for example, non-resident hunters and wildlife watchers pumped $340 million into the state's economy in 2006.[73] Fracking, however, is degrading the habitat of several species that are important attractions for hunters and wildlife viewers.[74]

A 2006 study found that the construction of well pads drove away female mule deer in the Pinedale Mesa area of Wyoming, which was opened to fracking in 2000, and that the deer stayed away from areas near well pads over time. The study suggested that natural gas development in the area was shifting mule deer from higher quality to lower quality habitat.[75] The mule deer population in the area dropped by 56 percent between 2001 and 2010 as fracking in the area continued and accelerated.[76]

Concerns have also been raised about the impact of natural gas development on pronghorn antelope. A study by the Wildlife Conservation Society documented an 82 percent reduction in high-quality pronghorn habitat in Wyoming's natural gas fields, which have historically been key wintering grounds.[77]

The Wyoming Game & Fish Department assigns "restitution values" for animals illegally killed in the state, with pronghorn valued at $3,000 per animal and mule deer at $4,000 per animal.[78] The decline of approximately 2,910 mule deer estimated to have occurred in the Pinedale Mesa between 2001 and 2010, using this valuation, would represent lost value of more than $11.6 million, although there is no way to determine the share of the decline attributable to natural gas development alone.[79]

"The decline of approximately 2,910 mule deer in the Pinedale Mesa, using this valuation, would represent lost value of more than $11.6 million."

The impact of fracking on wildlife-based recreation is, of course, only one of many ways in which harm to species translates into lasting economic damage. Wildlife provides many important ecosystem goods and services. (See next page.) Birds, for example, may keep insect and rodent populations in check, help to distribute seeds, and play other roles in

Loss of Ecosystem Services

Forests and other natural areas provide important services—they clean our air, purify our water, provide homes to wildlife, and supply scenic beauty and recreational opportunities. Many of these services would be costly to replicate—for example, as noted on page 14, the natural filtration provided by the forests of upstate New York has thus far enabled New York City to avoid the $6 billion expense of building a water filtration plant to purify the city's drinking water.

In recent years, economists have worked to quantify the value of the ecosystem services provided by various types of natural land. The annual value of ecosystem services provided by deciduous and evergreen forests, for example, has been estimated at $300 per acre per year.[71] Researchers with The Nature Conservancy and various Pennsylvania conservation groups have projected that 38,000 to 90,000 acres of Pennsylvania forest could be cleared for Marcellus shale development by 2030. The value of the ecosystem services provided by this area of forest, therefore, ranges from $11.4 million to $27 million per year.[72] Widespread land clearance for fracking jeopardizes the ability of the forest to continue to provide these valuable services.

Other natural features affected by fracking—including groundwater, rivers and streams, and agricultural land—provide similar natural services. The value of all of those services—and the risk that an ecosystem's ability to deliver them will be lost—must be considered when tallying the cost of fracking.

Oil and gas development fragments valuable natural habitat. Above, the Jonah gas field in Wyoming.
Credit: Bruce Gordon

the maintenance of healthy ecosystems. Adding these impacts to the impacts on hunters, anglers and wildlife-watchers magnifies the potential long-term costs of fracking from ecosystem damage.

Contribution to Global Warming

Global warming is the most profound challenge of our time, threatening the survival of key species, the health and welfare of human populations, and the quality of our air and water. Fracking produces pollution that contributes to the warming of the planet in greater quantities than conventional natural gas extraction.

"Emissions of methane during well completion from each uncontrolled fracking well impose approximately $139,000 in social costs related to global warming."

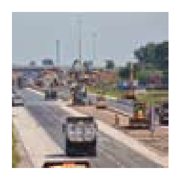
Fracking's primary impact on the climate is through the release of methane, which is a far more potent contributor to global warming than carbon dioxide. Over a 100-year timeframe, a pound of methane has 21 times the heat-trapping effect of a pound of carbon dioxide.[80] Methane is even more potent relative to carbon dioxide at shorter timescales.

Leaks during the extraction, transmission and distribution of natural gas release substantial amounts of methane to the atmosphere. Recent air monitoring near a natural gas field in Colorado led researchers at the National Oceanic and Atmospheric Administration and the University of Colorado, Boulder, to conclude that about 4 percent of the extracted gas was lost to the atmosphere, not counting the further losses that occur in transportation.[81]

Research by experts at Cornell University suggests that fracking is even worse for the climate than conventional gas production. Their study finds that methane leakage from fracking wells is at least 30 percent greater than, and perhaps double, leakage from conventional natural gas wells.[82]

Global warming threatens costly disruption to the environment, health and infrastructure. Economists have invested significant energy into attempting to quantify the "social cost" of emissions of global warming pollutants—that is, the negative impact on society per ton of emissions. A 2011 EPA study estimated the social cost of methane as lying within a range of $370 to $2,000 per ton. Each uncontrolled fracking well produces approximately 156 tons of methane emissions.[83] At a modest discount rate (3 percent) the social cost was $895 per ton in 2010.[84] Emissions of methane during well completion from a single uncontrolled fracking well, therefore, would impose $139,620 in social costs related to global warming.[85] This figure does not include emissions from other aspects of natural gas extraction, transmission and distribution, such as pipeline and compressor station leaks. Leakage from those sources further increases the impact of fracking on the climate—imposing impacts that may not be fully realized for decades or generations.

Impacts on Public Infrastructure and Services



Fracking imposes both immediate and long-term burdens on taxpayers through its heavy use of public infrastructure and heavy demand for public services.

Road Damage

Fracking requires the transportation of massive amounts of water, sand and fracking chemicals to and from well sites, damaging roads. In the northern tier of Pennsylvania,

Fracking requires millions of gallons of water and large quantities of sand and chemicals, all of which must be transported to well sites, inflicting damage on local roads. Above, a well site in Washington County, Pa. Credit: Robert Donnan

each fracking well requires approximately 400 truck trips for the transport of water and up to 25 rail cars' worth of sand.[86] The process of delivering water to a single fracking well causes as much damage to local roads as nearly 3.5 million car trips.[87]

"The state of Texas has convened a task force to review the impact of drilling activity on local roads and has approved $40 million in funding for road repairs in the Barnett Shale region."

Added up across dozens of well sites in a given area, these transportation demands are enough to lead to a noticeable increase in traffic—as well as strains on local roads. Between 2007 and 2010, for example, the amount of truck traffic on three major northern Pennsylvania highways increased by 125 percent, according to a regional transportation study. The study concluded that state and local governments will have to repave many roads every 7 to 8 years instead of every 15 years.[88]

The state of Texas has convened a task force to review the impact of drilling activity on local roads and has approved $40 million in funding for road repairs in the Barnett Shale region.[89] A 2010 Pennsylvania Department of Transportation document estimated that $265 million would be required for repair of roads affected by Marcellus Shale drilling.[90] Pennsylvania has negotiated bonding requirements with natural gas companies to cover the cost of repairs to local roads and some other states have done the same, but these requirements may not cover the full impact of fracking on roads, including impacts on major highways and the costs of traffic delays and vehicle repairs caused by congested or temporarily degraded roads.

Increased Demand for Water

The millions of gallons of water required for hydraulic fracturing come from aquifers, surface waterways, or water "recycled" from previous frack jobs.

In some areas, fracking makes up a significant share of overall water demand. In 2010, for example, fracking in the Barnett Shale region consumed an amount of water equivalent to 9 percent of the city of Dallas' annual water use.[91] An official at the Texas Water Development Board estimated that one county in the Eagle Ford Shale region will see the share of water consumption devoted to fracking and similar activities increase from zero a few years ago to 40 percent by 2020.[92] Unlike other uses, water used in fracking is lost to the water cycle forever, as it either remains in the well, is "recycled" (used in the fracking of new wells), or is disposed of in deep injection wells, where it is unavailable to recharge aquifers.

"Texas adopted a State Water Plan in 2012 that calls for $53 billion in investments in the state water system, including $400 million to address unmet needs in the mining sector (which includes hydraulic fracturing)."

Water withdrawals for fracking can harm local waterways (see page 20) and increase costs for agricultural and municipal water consumers (see page 31). They may also lead to calls for increased public investment in water infrastructure. Texas, for example, adopted a State Water Plan in 2012 that calls for $53 billion in investments in the state water system, including $400 million to address unmet needs in the mining sector (which includes hydraulic fracturing) by 2060.[93] Fracking is projected to account for 42 percent of water use in the Texas mining sector by 2020.[94]

Earthquakes

Fracking also has the potential to affect public infrastructure through induced earthquakes resulting from underground disposal of fracking wastewater. A recent report by the National Research Council identified eight cases in which seismic events were linked to wastewater disposal wells (not necessarily all for fracking wastes) in Ohio, Arkansas and Colorado.[95] In Ohio, which has become a popular location for the disposal of wastewater from Marcellus shale drilling, more than 500 million gallons of fracking wastewater were disposed of in underground wells in 2011.[96] That same year, the Youngstown, Ohio, area experienced a series of earthquakes, prompting Ohio officials to investigate potential links between the earthquakes and a nearby injection well. While the study did not determine a conclusive link between the injection well and the earthquakes, it did find that "[a] number of coincidental circumstances appear to make a compelling argument for the recent Youngstown-area seismic events to have been induced (by the injection well)."[97]

"The earthquakes raise concerns about the potential for damage to public infrastructure as well as private property."

The earthquakes that have occurred thus far have not caused significant damage, but they raise concerns about the potential for damage to public infrastructure (such as water and sewer lines) as well as private property.

Cleanup of Orphaned Wells

Gas and oil companies face a legal responsibility to plug wells properly when they cease to be productive and to "reclaim" well sites by restoring them to something approaching their original vegetated condition. The oil and gas industry, however, has a long track record of failing to clean up the messes it has made—leaving the public to pick up the tab.

Pennsylvania alone has more than 8,000 orphaned wells drilled over the last century and a half, and the Pennsylvania Department of Environmental Protection is unaware of the location or status of an additional 184,000 wells.[98]

Orphaned wells are not a problem of the past; newer wells can be orphaned by their operators, too, and left to taxpayers to clean up. Nearly 12,000 coal-bed methane wells in Wyoming were idle as of 2011, neither producing nor plugged.[99] Wyoming officials are concerned that several companies that operate coal-bed methane wells may file for bankruptcy if natural gas prices do not rebound or if the companies cannot sell off some assets to raise capital to comply with state environmental protections. If that were to happen, the state could be forced to plug and remediate the idled wells.

"A 2011 study of a Marcellus Shale well by researchers with the University of Pittsburgh estimated the cost of site reclamation (including reclamation of retention ponds and repairs to public roads) at $500,000 to $800,000 per well site."

Another way in which the public may face exposure to costs is when a well plug fails, requiring attention years later. Chemical, mechanical or thermal stress can cause the cement to

Volunteer firefighters respond to a fire in a wastewater pit at an Atlas Energy Resources well site in Washington County, Pa., in March 2010. Fracking places increased demands on emergency responders, creating new dangers that require additional training, and increasing demands for response to traffic accidents involving heavy trucks. Credit: Robert Donnan crack or loosen and allow contamination from saline aquifers or gas-bearing layers to reach freshwater aquifers. The risk of plug failure increases over time.[100] In some states, such as Pennsylvania, plugging and reclamation bonds are released one year after a well is plugged, leaving the state with no way to hold drillers accountable for the cost of plugging wells that fail later.

The Pennsylvania Department of Environmental Protection estimates that plugging a 3,000 foot-deep oil or gas well and reclaiming the drill site costs an average of $60,000.[101] However, some well reclamation costs have exceeded $100,000.[102] And Cabot Oil & Gas Corporation claims to have spent $730,000 per well to cap three shale gas wells in Pennsylvania.[103] A 2011 study of a Marcellus Shale well by researchers with the University of Pittsburgh estimated the cost of site reclamation (including reclamation of retention ponds and repairs to public roads) at $500,000 to $800,000 per well site.[104]

While estimates of the costs of plugging and remediation of fracked wells vary, those costs almost always exceed a state's bonding requirements. Pennsylvania's recently revised bonding requirements, for example, require drillers to post maximum bonds of only $4,000 per well for wells less than 6,000 feet in depth and $10,000 per well for wells deeper than 6,000 feet, creating the potential for the public to be saddled with tens or hundreds of thousands of dollars in liability for plugging and reclamation of abandoned wells whose owners have gone bankrupt or walked away from their responsibilities.[105] The experience of previous resource extraction booms and busts suggests that the full bill for cleaning up orphaned wells may not come due for decades.

In parts of the country, fracking takes place in close proximity to homes, schools and hospitals, creating the potential for conflict. A Texas study has found that some homes near fracking well sites have lost value. Above, a natural gas flare near homes in Hickory, Pa. Credit: Robert Donnan

Emergency Response Needs

Increasing traffic—especially heavy truck traffic—has contributed to an increase in traffic accidents and fatalities in some areas in which fracking has unleashed a drilling boom, as well as an increase in demands for emergency response. In the Bakken Shale oil region of North Dakota for example, the number of highway crashes increased by 68 percent between 2006 and 2010, with the share of crashes involving heavy trucks also increasing over that period. The estimated cost of those crashes increased by $31 million.[106]

"A 2011 survey in eight Pennsylvania counties found that 911 calls had increased in seven of them, with the number of calls increasing in one county by 49 percent over three years, largely due to an increase in incidents involving heavy trucks."

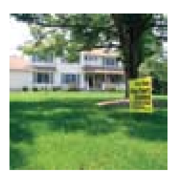
The need to address traffic accidents is one driver of increased need for emergency response in communities experiencing fracking. A 2011 survey by StateImpact Pennsylvania in eight counties found that 911 calls had increased in seven of them, with the number of calls increasing in one county by 49 percent over three years, largely due to an increase in incidents involving heavy trucks.[107]

Social Dislocation and Social Service Costs

The influx of temporary workers that often accompanies fracking also puts a squeeze on housing supplies, creating social dislocation that, in some cases, creates new demand for government social services. Rental prices have doubled or tripled in communities experiencing a boom in Marcellus Shale drilling.[108] Overheated local housing markets have driven lower income renters into substandard housing or homelessness. Elderly residents have faced a shortage of subsidized housing.[109] Requests for assistance from social service agencies have increased.[110] In Bradford County, Pa., the local children and youth services agency increased its spending on housing subsidies by 50 percent or $10,000 per year.[111] In the same county, a government agency purchased and distributed tents for use as temporary housing.[112] In Greene County, in southwestern Pennsylvania, the documented number of homeless jumped from zero to 40 in a single year.[113] Children of families that lose permanent housing may be at risk of being separated from their families and placed into foster care. A 2010 survey of Pennsylvania local governments in municipalities experiencing Marcellus Shale drilling activity found that more governments reported an increase in municipal expenditures since the onset of fracking than reported an increase in revenues.[114]

"In Greene County, in southwestern Pennsylvania, the documented number of homeless jumped from zero to 40 in a single year."

Broader Economic Impacts



Fracking imposes damage on the environment, public health and public infrastructure, with significant economic costs. But poorly thought-out resource extraction also has a legacy of undercutting the long-term economic prospects of the very "boomtowns" it creates.

A 2008 study by the firm Headwaters

Economics found that Western counties that have relied on fossil fuel extraction are doing worse economically compared with peer communities and are less well-prepared for growth in the future, due to a less-diversified economy, a less-educated workforce, and greater disparities in income.[115]

In addition, fracking can undermine local economies in many ways, including through its impacts on housing and agriculture.

Value of Residents' Homes at Risk

Fracking can reduce the value of nearby properties as a result of both actual pollution and the stigma that may come from proximity to industrial operations and the potential for future impacts. A 2010 study in Texas concluded that homes valued at more than $250,000 and within 1,000 feet of a well site saw their values decrease by 3 to 14 percent—there was no discernible impact on property values beyond that distance or for lower-priced houses.[116] A 2001 study of property values in La Plata County, Colorado, found that properties with a coalbed methane well had seen their sales value decrease by 22 percent.[117] Even where impacts on sales values are difficult to establish, chronic conditions caused by fracking—such as odor, traffic, noise, concerns about pollution of the air and water, earthquake concerns and visual impacts—may adversely affect residents' use and enjoyment of their homes.

"A 2010 study in Texas concluded that homes valued at more than $250,000 and within 1,000 feet of a well site saw their values decrease by 3 to 14 percent."

Properties on and near locations where fracking is taking place may also be more difficult to finance and insure, potentially affecting their value. Mortgage lenders and insurers have recently taken steps to protect themselves from fracking-related risks. Several mortgage lenders have begun to require extensive buffer zones around homes on land with gas leases before issuing a new mortgage or to refuse to issue new mortgages on land with natural gas leases.[118] For example, Brian and Amy Smith live across the street from a gas drilling site in Daisytown, Pa. In the spring of 2012, Quicken Loans denied their mortgage application, stating that "Unfortunately, we are unable to move forward with this loan. It is located across the street from a gas drilling site." The Smiths were also rejected by two other national lenders.[125]

In addition, in July 2012, Nationwide Insurance issued a statement clarifying that its policies do not cover damages related to fracking, noting that "the exposures presented by hydraulic fracturing are too great to ignore."[119] Nationwide's announcement drew attention to the fact that standard homeowners' insurance policies do not cover damage related to fracking.

Farms in Jeopardy

Fracking largely takes place in rural areas. Several aspects of fracking have the potential to harm farmers.

Direct exposure to fracking wastewater can harm livestock. Researchers at Cornell University have identified multiple instances of harm to animals associated with natural gas operations in Colorado, Louisiana, New York, Ohio, Pennsylvania and Texas. In one case examined by the researchers, 140 cows were exposed when the liner of a wastewater impoundment was slit, enabling wastewater to flow onto a pasture and into a pond the cattle used as a water supply. Of those 140 cows, approximately 70 died. Assuming an average cost per cow of $1,600[120], the loss of

"The loss of 70 cows from a single incident would have an impact of at least $112,000."

70 cows from a single incident would have an impact of at least $112,000. In addition to this direct replacement cost, exposure of livestock to contaminants from fracking is likely to cost farmers in other ways, for example, by impeding the ability of animals to reproduce or reducing the ability of a farmer to market his or her livestock.

Researchers at Penn State University have identified a link between increased drilling activity in the Marcellus Shale and decreased production at dairy farms in counties where drilling is taking place. The five counties in which drilling activity was the heaviest experienced an 18.5 percent reduction in milk production between 2007 and 2010.[121] The researchers did not reach a conclusion as to the cause of the decline. But another review of the community implications of fracking suggested that rising transportation costs caused by workforce competition with gas drilling has added a new economic challenge for dairy farmers.[122] The demise of farming in a community threatens to also bring down stores and industries that were built to support farmers, eroding a community's economic base.

In arid western states, some farmers face higher costs for water as a result of competing demands from fracking. A 2012 auction of unallocated water conducted by the Northern Water Conservation District saw natural gas industry firms submit high bids, with the average price of water sold in the auction increasing from $22 per acre-foot in 2010 to $28 per acre-foot in the first part of 2012.[123] For the 25,000 acre-feet of water auctioned, this would amount to an added cost of $700,000.

Fracking poses threats to farming, both directly through the potential loss of livestock due to exposure to toxic contaminants, and indirectly by increasing farmers' costs of doing business during the "boom" portion of the boom-bust cycle of development. Here, cows graze in Erie, Colorado, which has experienced fracking activity. Credit: Jill/Blue Moonbeam Studio.

Finally, farmers engaged in organic agriculture have raised concerns that fracking could make it more difficult for them to sell their products to health-conscious consumers. One New York City food co-op, for example, has already stated that they may stop purchasing agricultural products from New York state farms in areas where fracking takes place.[124]

Who Pays the Costs of Fracking?

The oil and gas industry is unlikely ever to be held accountable for many of the costs of fracking documented in this report—at least under current law.

Time and again in the history of the oil and gas industry, legal safeguards have proven inadequate to protect the environment and communities from exposure to long-term costs. The public can be exposed to many different and significant costs from fracking for several reasons:

- **Inadequate financial assurance.** The boom-bust cycle typical of the oil and gas industry means that many firms (or their subcontractors) may be unable or unwilling to fulfill their financial obligations to properly plug wells, reclaim land, remediate environmental problems, and compensate those harmed by their activities. State bonding requirements are intended to protect the public by ensuring that financial resources exist to cover the cost of well plugging and reclamation, but the amounts of those bonds are generally too low to pay for proper well closure, and state laws generally do not require drillers to obtain bonds to cover the cost of off-site environmental remediation or compensation to victims.

- **Delayed appearance of harm.** Some damages from fracking are apparent right away—for example, the appearance of tainted well water immediately after fracking of a nearby well. But other damages—especially ecosystem and health damages—may not appear for years or even decades, making it likely that the individuals and companies responsible will be long gone from the scene by the time the scope of the damage becomes apparent. This is particularly worrisome given concerns about the potential long-term impact of fracking and wastewater disposal on precious groundwater supplies.

- **Diffuse, regional impacts.** Some impacts of fracking only appear when many wells are drilled in a concentrated geographic area. For example, the erosion caused by clearance of a single well pad may not be enough to harm wildlife in a local stream, but the clearance of land for dozens of wells in the same area may have a harmful cumulative impact. In these cases, assigning legal responsibility for the damage to any single well may prove difficult or impossible.

- **Inability to access legal remedies.** Those who are harmed by fracking can face an uphill battle in the legal system. Litigation is frequently a lengthy, expensive, time-consuming and difficult road for citizens to pursue in seeking to resolve claims of damage from environmental conditions. This is particularly true with regard to health impacts. It is extraordinarily difficult, for example, to meet the legal standards of proof that an individual's illness was caused by exposure to a particular toxic chemical at a particular time. Even where property damage is concerned, such litigation typically requires expert analysis and testimony to prove causation and diminished value of the affected property.

As a result, many of the costs of fracking are often borne not by the companies that benefit, but by nearby residents, taxpayers, those whose enjoyment of clean air, clean water and abundant wildlife is impacted by fracking, and even by future generations.

Infographic design: Jenna Leschuk

Accounting for the True Costs of Fracking: Conclusion and Recommendations

Fracking harms the environment, public health and our communities in many ways.

If fracking is to continue, the minimum that citizens should expect is the enforcement of tough rules to reduce fracking damage and up-front financial assurances that guarantee that the oil and gas industry cleans up the damage it does cause and compensates any victims. Current laws, however, are inadequate to ensure that even this basic standard of protection is met. Failing to hold the oil and gas industry accountable not only leaves the public exposed to many types of costs, but it also creates a disincentive for the industry to take action to prevent accidents and environmental contamination.

Federal, state and local governments should **hold the oil and gas industry accountable for the costs of fracking** using a variety of financial tools, including:

- **Bonding** – Oil and gas companies should be required to post bonds (or other forms of financial assurance) sufficient to plug wells and reclaim well sites, pay for road repairs and other physical damage caused by fracking, remediate environmental contamination, fully compensate anyone harmed by activities at well sites, and address other costs imposed by fracking. Requiring drilling companies to post bonds for these expenses ensures that the oil and gas industry will be able to take care of its responsibilities to the public and the environment even amid the "boom-bust" cycles typical of the oil and gas industry.

- **Fees, taxes and other charges** – Bonding may not be the best solution for recouping every cost imposed by fracking. For example, natural gas companies could not be required to take out bonds to cover expenses related to a single well's contribution to global warming—the effect of which might be felt half a world away. While strong regulation should be used to limit the broader environmental, public health and community impacts of fracking, fees and other charges can also recoup for the public some of the costs imposed by fracking and create an economic incentive for the oil and gas industry to reduce its impact.

The mounting evidence of fracking's impact on our environment, health and communities is enough to spur reconsideration of when and under what circumstances it is permitted to take place. If fracking is permitted to continue, Americans deserve to know that the oil and gas industry—not the public at large—will pick up the tab.

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Summary

At hundreds of thousands of hazardous waste sites across the country, groundwater contamination remains in place at levels above cleanup goals. The most problematic sites are those with potentially persistent contaminants including chlorinated solvents recalcitrant to biodegradation, and with hydrogeologic conditions characterized by large spatial heterogeneity or the presence of fractures. While there have been success stories over the past 30 years, the majority of hazardous waste sites that have been closed were relatively simple compared to the remaining caseload. In 2004, the U.S. Environmental Protection Agency (EPA) estimated that more than $209 billion would be needed to mitigate these hazards over the next 30 years—likely an underestimate because this number did not include sites where remediation was already underway or where remediation had transitioned to long-term management.

The Department of Defense (DoD) exemplifies a responsible party that has made large financial investments (over $30 billion) in hazardous waste remediation to address past legacies of their industrial operations. Although many hazardous waste sites at military facilities have been closed with no further action required, meeting goals like drinking water standards in contaminated groundwater has rarely occurred at many complex DoD sites. It is probable that these sites will require significantly longer remediation times than originally predicted, and thus, continued financial demands for monitoring, maintenance, and reporting.

In this context, the Water Science and Technology Board, under the auspices of the National Research Council (NRC), convened a committee to assess the future of the nation's groundwater remediation efforts focusing on the technical, economic, and institutional challenges facing the Army and other responsible parties as they pursue site closure. Previous NRC reports concluded that complete restoration of contaminated groundwater is unlikely to be achieved for many decades for a substantial number of sites, in spite of the fact that technologies for removing contaminants from groundwater have continued to evolve and improve. Since the most recent NRC report in 2005, better understanding of technical issues and barriers to achieving site closure have become evident. The following questions comprised the statement of task for this Committee, which considered both public and private hazardous waste sites.

Size of the Problem. At how many sites does residual contamination remain such that site closure is not yet possible? At what percentage of these sites does residual contamination in groundwater threaten public water systems?

Current Capabilities to Remove Contamination. What is technically feasible in terms of removing a certain percentage of the total contaminant mass? What percent removal would be needed to reach unrestricted use or to be able to extract and treat groundwater for potable reuse? What should be the definition of "to the extent practicable" when discussing contaminant mass removal?

Correlating Source Removal with Risks. How can progress of source remediation be measured to best correlate with site-specific risks? Recognizing the long-term nature of many problems, what near-term endpoints for remediation might be established? Are there regulatory barriers that make it impossible to close sites even when the site-specific risk is negligible and can they be overcome?

The Future of Treatment Technologies. The intractable nature of subsurface contamination suggests the need to discourage future contaminant releases, encourage the use of innovative and multiple technologies, modify remedies when new information becomes available, and clean up sites sustainably. What progress has been made in these areas and what additional research is needed?

Better Decision Making. Can adaptive site management lead to better decisions about how to spend limited resources while taking into consideration the concerns of stakeholders? Should life cycle assessment become a standard component of the decision process? How can a greater understanding of the limited current (but not necessarily future) potential to restore groundwater be communicated to the public?

MAGNITUDE OF THE PROBLEM

Chapter 2 presents information on the major federal and state regulatory programs under which hazardous waste is cleaned up to determine the size and scope of these programs. The Committee sought to determine (1) the number of sites that have not yet reached closure, (2) principal chemicals of concern, (3) remediation costs expended to date, (4) cost estimates for reaching closure, and (5) the number of sites affecting local water supplies. Information was gathered for sites in the EPA's Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), Resource Conservation and Recovery Act (RCRA), and Underground Storage Tank (UST) programs; sites managed by the DoD, the Department of Energy (DOE) and other federal agencies; and sites under state purview (e.g., state Superfund, voluntary cleanup programs, and Brownfields programs). The metrics and milestones across all these programs differ, making comparisons and the elimination of overlap difficult. Nonetheless, the Committee used these data to estimate the number of complex sites, the likelihood that sites affect a drinking water supply, and the remaining costs associated with remediation.

At least 126,000 sites across the country have been documented that have residual contamination at levels preventing them from reaching closure. This number is likely to be an underestimate of the extent of contamination in the United States for many reasons. For example, the CERCLA and RCRA programs report the number of facilities, which are likely to have multiple sites. The total does not include DoD sites that have reached *remedy-in-place* or *response complete*, although some such sites may indeed contain residual contamination. Although there is overlap between some of the categories, in the Committee's opinion it is not significant enough to dismiss the conclusion that the total number of 126,000 is an underestimate.

No information is available on the total number of sites with contamination in place above levels allowing for unlimited use and unrestricted exposure, although the total is certainly greater than 126,000. For the CERCLA program, many facilities have been delisted with contamination remaining in place at levels above unlimited use and unrestricted exposure. Depending on state closure requirements, USTs are often closed with contamination remaining due to the biodegradability of petroleum hydrocarbons. Most of the DOE sites, including those labeled as "completed," contain recalcitrant contamination that in some cases could take hundreds of years to reach levels below those allowing for unlimited use and unrestricted exposure.

A small percentage (about 12,000 or less than 10 percent) of the 126,000 sites are estimated by the Committee to be complex from a hydrogeological and contaminant perspective. This total represents the sum of the remaining DoD, CERCLA, RCRA, and DOE sites and facilities, based on the assumption that many of the simpler sites in these programs have already been dealt with.

Approximately ten percent of CERCLA facilities affect or significantly threaten public water supply systems, but similar information from other programs is largely unavailable. Surveys of groundwater quality report that 0.34 to 1 percent of raw water samples from wells used for drinking water (including public supply and private wells) contain mean volatile organic compound (VOC) concentrations greater than the applicable drinking water standard, although there are no data linking these exceedances to specific hazardous waste sites. The percentage of drinking water wells with samples containing low-level VOC concentrations is likely to be higher for areas in close proximity to contaminated sites, for urban rather than rural areas, and in shallow unconfined sandy aquifers.

Information on cleanup costs incurred to date and estimates of future costs are highly uncertain. Despite this uncertainty, the estimated "cost to complete" of $110-127 billion is likely to be an underestimate of future liabilities. Remaining sites include some of the most difficult to remediate sites, for which the effectiveness of planned remediation remains uncertain given their complex site conditions. Furthermore, many of the estimated costs do not fully consider the cost of long-term management of sites that will have contamination remaining in place at levels above those allowing for unlimited use and unrestricted exposure for the foreseeable future.

The nomenclature for the phases of site cleanup and cleanup progress are inconsistent between federal agencies, between the states and federal government, and in the private sector. Partly because of these inconsistencies, members of the public and other stakeholders can and have confused the concept of "site closure" with achieving unlimited use and unrestricted exposure goals for the site, such that no further monitoring or oversight is needed. In fact, many sites thought of as "closed" and considered as "successes" will require oversight and funding for decades and in some cases hundreds of years in order to be protective. CERCLA and other programs have reduced public health risk from groundwater contamination by preventing unacceptable exposures in water or air, but not necessarily by reducing contamination levels to drinking water standards throughout the affected aquifers.

REMEDIAL OBJECTIVES, REMEDY SELECTION, AND SITE CLOSURE

Chapter 3 focuses on the remedial objectives dictated by the common regulatory frameworks under which groundwater cleanup generally occurs because such objectives are often a substantial source of controversy. This is particularly true for complex sites, where the remedial objectives are drinking water standards (denoted as maximum contaminant levels or MCLs) and hence are typically difficult, if not impossible, to attain for many decades. Faced with shrinking budgets and a backlog of sites that include an increasing percentage of complex sites, some states (e.g., California) have proposed closing large numbers of petroleum underground storage tank sites deemed to present a low threat to the public, despite the affected groundwater not meeting remedial goals at the time of closure. Other states (New Jersey and Massachusetts) have sought to privatize parts of the remediation process in order to unburden state and local regulatory agencies.

EPA's current remediation guidance provides substantial flexibility to the remedy selection process in a number of ways, although there are legal and practical limits to this flexibility. There are several alternatives to traditional cleanup goals, like technical impracticability waivers, that can allow sites with intractable contamination to move more expeditiously through the phases of cleanup while still minimizing risks to human health and the environment. The chapter also discusses sustainability concepts, which have become goals for some stakeholders and could impact the remedy selection process. The following conclusions and recommendations discuss the value of exploring goals and remedies based on site-specific risk, sustainability, and other factors.

By design (and necessity), the CERCLA process is flexible in (a) determining the beneficial uses of groundwater; (b) deciding whether a regulatory requirement is an applicable or relevant and appropriate requirement (ARAR) at a site; (c) using site-specific risk assessment to help select the remedy; (d) using at least some sustainability factors to help select the remedy; (e) determining what is a reasonable timeframe to reach remedial goals; (f) choosing the point of compliance for monitoring; and (g) utilizing alternate concentration limits, among others. **These flexible approaches to setting remedial objectives and selecting remedies should be explored more fully by state and federal regulators, and EPA should take administrative steps to ensure that existing guidance is used in the appropriate circumstances.**

To fully account for risks that may change over time, **risk assessment at contaminated groundwater sites should compare the risks from taking "no action" to the risks associated with the implementation of each remedial alternative over the life of the remedy.** Risk assessment at complicated groundwater sites is often construed relatively narrowly, with an emphasis on risks from drinking water consumption and on the MCL. Risk assessments should include additional consideration of (a) short-term risks that are a consequence of remediation; (b) the change in residual risk over time; (c) the potential change in risk caused by future changes in land use; and (d) both individual and population risks.

Progress has been made in developing criteria and guidance concerning how to consider sustainability in remedy selection. However, in the absence of statutory changes, remedy selection at private sites regulated under CERCLA cannot consider the social factors, and may not include the other economic factors, that fall under the definition of sustainability. At federal facility sites, the federal government can choose, as a matter of policy, to embrace sustainability concepts more comprehensively. Similarly, private companies may adopt their own sustainable remediation policies in deciding which remedial alternatives to support at their sites. **New guidance is needed from EPA and DoD detailing how to consider sustainability in the remediation process to the extent supported by existing laws, including measures that regulators can take to provide incentives to companies to adopt more sustainable measures voluntarily.**

CURRENT CAPABILITIES TO REMOVE/CONTAIN CONTAMINATION

Chapter 4 updates the 2005 NRC report on source removal by providing brief reviews of the major remedial technologies that can be applied to complex hazardous waste sites, particularly those with source zones containing dense nonaqueous phase liquids like chlorinated solvents and/or large down-gradient dissolved plumes. This includes surfactant flushing, cosolvent flushing, *in situ* chemical oxidation, pump and treat for hydraulic containment, physical containment, *in situ* bioremediation, permeable reactive barriers, and monitored natural attenuation. Well-established technologies including excavation, soil vapor extraction/air sparging, and solidification/stabilization are not discussed because they have been presented in prior publications and minimal advancements in these technologies have occurred over the past five to ten years. To address what is technically feasible in terms of removing a certain percentage of the total contaminant mass from the subsurface, the sections discuss current knowledge regarding performance and limitations of the technologies, identify remaining gaps in knowledge, and provide case studies supporting these assessments. The following conclusions and recommendations arise from this chapter.

Significant limitations with currently available remedial technologies persist that make achievement of MCLs throughout the aquifer unlikely at most complex groundwater sites in a time frame of 50-100 years. Furthermore, future improvements in these technologies are likely to be incremental, such that long-term monitoring and stewardship at sites with groundwater contamination should be expected.

The Committee could identify only limited data upon which to base a scientifically supportable comparison of remedial technology performance for the technologies reviewed in Chapter 4. There have been a few well-studied demonstration projects and lab-scale research studies, but adequate performance documentation generated throughout the remedial history at sites either is not available or does not exist for the majority of completed remediation efforts. Furthermore, poor design, poor application, and/or poor post-application monitoring at typical (i.e., non-research or demonstration) sites makes determination of the best practicably achievable performance difficult.

There is a clear need for publically accessible databases that could be used to compare the performance of remedial technologies at complex sites (performance data could be concentration reduction, mass discharge reduction, cost, time to attain drinking water standards, etc.). To ensure that data from different sites can be pooled to increase the statistical power of the database, a standardized technical protocol would be needed, although it goes beyond the scope of this report to provide the details of such a protocol.

Additional independent reviews of source zone technologies are needed to summarize their performance under a wide range of site characteristics. Since NRC (2005), only thermal and *in situ* chemical oxidation technologies have undergone a thorough, independent review. Other source zone technologies should also be reviewed by an independent scientific group. Such reviews should include a description of the state of the practice, performance metrics, and sustainability information of each type of remedial technology so that there is a trusted source of information for use in the remedial investigation/feasibility study process and optimization evaluations.

IMPLICATIONS OF CONTAMINATION REMAINING IN PLACE

Chapter 5 discusses the potential technical, legal, economic, and other practical implications of the finding that groundwater at complex sites is unlikely to attain unlimited use and unrestricted exposure levels for many decades. First, the failure of hydraulic or physical containment systems, as well as the failure of institutional controls, could create new exposures. Second, toxicity information is regularly updated, which can alter drinking water standards, and contaminants that were previously unregulated may become so. In addition, pathways of exposure that were not previously considered can be found to be important, such as the vapor intrusion pathway. Third, treating contaminated groundwater for drinking water purposes is costly and, for some contaminants, technically challenging. Finally, leaving contamination in the subsurface may expose the landowner, property manager, or original disposer to complications that would not exist in the absence of the contamination, such as natural resource damages, trespass, and changes in land values. Thus, the risks and the technical, economic, and legal complications associated with residual contamination need to be compared to the time, cost, and feasibility involved in removing contamination outright. The following conclusions and recommendations are made.

Implementing institutional controls at complex sites is likely to be difficult. Although EPA has developed a number of measures to improve the reliability, enforceability, and funding of institutional controls, their long-term efficacy has yet to be determined. Regulators and federal responsible parties should incorporate a more significant role for local citizens in the long-term oversight of institutional controls. **A national, searchable, geo-referenced institutional control database covering as many regulatory programs as practical as well as all federal sites would help ensure that the public is notified of institutional controls.**

New toxicological understanding and revisions to dose-response relationships will continue to be developed for existing chemicals, such as trichloroethene and tetrachloroethene, and for new chemicals of concern, such as perchlorate and perfluorinated chemicals. The implications of such evolving understanding include identification of new or revised ARARs (either more or less restrictive than existing ones), potentially leading to a determination that the existing remedy at some hazardous waste sites is no longer protective of human health and the environment. **Modification of EPA's existing CERCLA five-year review guidance would allow for more expeditious assessment of the protectiveness of the remedy based on any changes in EPA toxicity factors, drinking water standards, or other risk-based standards.**

Careful consideration of the vapor intrusion pathway is needed at all sites where VOCs are present in the soil or groundwater aquifer. Although it has been recognized for more than a decade that vapor intrusion is a potential exposure pathway of concern, a full understanding of the risks over time and appropriate methods for characterizing them are still evolving. Mitigation strategies such as subslab depressurization can prevent vapor intrusion exposure. As a precautionary measure, vapor mitigation could be built into all new construction on or near known VOC groundwater plumes. Vapor mitigation systems require monitoring over the long-term to ensure that they are operating properly.

TECHNOLOGY DEVELOPMENT TO SUPPORT LONG-TERM MANAGEMENT

Despite years of characterization and implementation of remedial technologies, many complex federal and private industrial facilities with contaminated groundwater will require long-term management that could extend for decades or longer. Chapter 6 discusses technological developments that can aid in the transition from active remediation to more passive strategies and provide more cost-effective and protective long-term management of complex sites. In particular, transitioning to and improving long-term management can be achieved through (1) better understanding of the spatial distribution of contaminants, exposure pathways, and processes controlling contaminant mass flux and attenuation along exposure pathways; (2) improved spatio-temporal monitoring of groundwater contamination through better application of conventional monitoring techniques, the use of proxy measurements, and development of sensors; and (3) application of emerging diagnostic and modeling tools. The chapter also explores emerging remediation technologies that have yet to receive extensive field testing and evaluation, and it reviews the state of federal funding for relevant research and development. The following conclusions and recommendations are offered.

Long-term management of complex sites requires an appropriately detailed understanding of geologic complexity and the potential distribution of contaminants among the aqueous, vapor, sorbed, and NAPL phases, as well as the unique biogeochemical dynamics associated with both the source area and downgradient plume. Recent improvements to the understanding of subsurface biogeochemical processes have not been accompanied by cost-effective site characterization methods capable of fully distinguishing between different contaminant compartments. Management of residual contamination to reduce the exposure risks via the vapor intrusion pathway is challenged by the highly variable nature of exposure, as well as uncertain interactions between subsurface sources and indoor background contamination.

Existing protocols for assessing monitored natural attenuation and other remediation technologies should be expanded to integrate compound-specific isotope analysis and molecular biological methods with more conventional biogeochemical characterization and groundwater dating methods. The development of molecular and isotopic diagnostic tools has significantly enhanced the ability to evaluate the performance of degradation technologies and monitored natural attenuation at complex sites.

Although the Committee did not attempt a comprehensive assessment of research needs, research in the following areas would help address technical challenges associated with long-term management at complex contaminated sites (see Chapter 6 for a more complete list):

- **Remediation Technology Development**. Additional work is needed to advance the development of emerging and novel remediation technologies, improve their performance, and understand any potential broader environmental impacts. A few developing remediation techniques could provide more cost-effective remediation for particular combinations of contaminants and site conditions at complex sites, but they are in the early stages of development.

- **Tools to Assess Vapor Intrusion**. Further research and development should identify, test, and demonstrate tools and paradigms that are practicable for assessing the significance of vapor intrusion, especially for multi-building sites and preferably through short-term diagnostic tests. Development of real-time unobtrusive and low-cost air quality sensors would allow verification of those short-term results over longer times at buildings not needing immediate mitigation.

- **Modeling**. Additional targeted modeling research and software development that will benefit the transition of sites from active remediation to long-term management should be initiated. Particular needs include concepts and algorithms for including the processes of back-diffusion and desorption in screening and plume models, and the development of a larger suite of intermediate-complexity modeling tools to support engineering design for source remediation.

Overall research and development have been unable to keep pace with the needs of practitioners trying to conduct remediation on complex sites. Currently, a national strategy for technology development to support long-term management of complex sites is lacking. It is not clear that the pertinent federal agencies will be capable of providing the funding and other support for the fundamental research and development that is necessary to meet the challenges facing complex sites. A comprehensive assessment of future research needs, undertaken at the federal level and involving coordination between federal agencies, would allow research funding to be allocated in an efficient and targeted manner.

BETTER DECISION MAKING DURING THE LONG-TERM MANAGEMENT OF COMPLEX GROUNDWATER CONTAMINATION SITES

The fact that at most complex groundwater sites drinking water standards will not be attained for decades should be more fully reflected in the decision making process of existing cleanup programs. Thus, Chapter 7 provides a series of recommendations that will accelerate the transition of sites to one of three possible end states: (1) *closure* in which unlimited use and unrestricted exposure levels have been attained; (2) *long-term passive management* (e.g., using natural attenuation with or without monitoring, physical containment, permeable reactive barriers, and/or institutional controls), and (3) *long-term active management* (e.g., indefinite hydraulic containment using pump and treat). The acceleration of this transition to one of three end states is premised on using remedies that are fully protective of human health and the environment in combination with more rapid acceptance of alternative end states other than clean closure.

An alternative approach for better decision making at complex sites is shown in Figure 7-2. It includes the processes currently followed at all CERCLA facilities and at many complex sites regulated under other federal or state programs (RCRA or state Superfund), but it provides more detailed guidance for sites where recalcitrant contamination remains in place at levels above those allowing for unlimited use and unrestricted exposure. This alternative approach diverges from the status quo by requiring the explicit charting of risk reduction (as indicated by, e.g., contaminant concentration reduction) over time. Specifically, if data indicate that contaminant concentrations are approaching an asymptote, resulting in exponential increases in the unit cost of the remedy, then there is limited benefit in its continued operation. At this point of diminishing returns, it is appropriate to assess whether to take additional remedial action (if legally possible) or whether to transition to more passive long-term management.

If asymptotic conditions have occurred, a *transition assessment* is performed. The transition assessment evaluates each of the relevant alternatives (remedy modification or replacement, passive or active long-term management) based on the statutory and regulatory remedy selection criteria. This includes consideration of the risk from residual contamination in subsurface zones, life-cycle costs and the incremental costs compared to the level of risk reduction achieved, and the likely reaction of stakeholders. The following conclusions and recommendations about this alternative approach are made.

At many complex sites, contaminant concentrations in the plume remain stalled at levels above cleanup goals despite continued operation of remedial systems. There is no clear path forward to a final end state embodied in the current cleanup programs, such that money continues to be spent, with no concomitant reduction in risks. **If the effectiveness of site remediation reaches a point of diminishing returns prior to reaching cleanup goals and optimization has been exhausted, the transition to monitored natural attenuation or some other active or passive management should be considered using a formal evaluation.** This transition assessment would determine whether a new remedy is warranted at the site or whether long-term management is appropriate.

Five-year reviews are an extremely valuable source of field data for evaluating the performance of remedial strategies that have been implemented at CERCLA facilities and could be improved. To increase transparency and allow EPA, the public, and other researchers to assess lessons learned, more should be done, on a national basis, to analyze the results of five-year reviews in order to evaluate the current performance of implemented technologies. **EPA's technical guidance for five-year reviews should be updated to provide a uniform protocol for analyzing the data collected during the reviews, reporting their results, and improving their quality.**

Public involvement tends to diminish once remedies at a site or facility are in place. No agency has a clear policy for sustaining public involvement during long-term management. Regulators and federal responsible parties should work with members of existing advisory groups and technical assistance recipients to devise models for ongoing public oversight once remedies are in place. Such mechanisms may include annual meetings, Internet communications, or the shifting of the locus of public involvement to permanent local institutions such as public health departments.

Although the cost of new remedial actions may decrease at complex sites if more of them undergo a transition to passive long-term management, there will still be substantial long-term funding obligations. Failure to fund adequately the long-term management of complex sites may result in unacceptable risks to the public due to unintended exposure to site contaminants.

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Preface

Despite nearly 40 years of intensive efforts in the United States as well as in other industrialized countries worldwide, restoration of groundwater contaminated by releases of anthropogenic chemicals to a condition allowing for unrestricted use and unlimited exposure (UU/UE) remains a significant technical and institutional challenge. Recent (2004) estimates by EPA indicate that expenditures for soil and groundwater cleanup at over 300,000 sites through 2033 may exceed $200 billion (not adjusted for inflation), and many of these sites have experienced groundwater impacts.

One dominant attribute of the nation's efforts on subsurface remediation efforts has been lengthy delays between discovery of the problem and its resolution. Reasons for these extended timeframes are now well known: ineffective subsurface investigations, difficulties in characterizing the nature and extent of the problem in highly heterogeneous subsurface environments, remedial technologies that have not been capable of achieving restoration in many of these geologic settings, continued improvements in analytical detection limits leading to discovery of additional chemicals of concern, evolution of more stringent drinking water standards, and the realization that other exposure pathways, such as vapor intrusion, pose unacceptable health risks. A variety of administrative and policy factors also result in extensive delays, including, but not limited to, high regulatory personnel turnover, the difficulty in determining cost-effective remedies to meet cleanup goals, and allocation of responsibility at multiparty sites.

Over the past decade, however, remedial technologies have shown increased effectiveness in removing contaminants from groundwater, and the use of more precise characterization tools and other diagnostic technologies have improved our ability to achieve site-specific remedial action objectives within a reasonable time frame at an increasing number of sites. For example, of the over 1,700 National Priority List sites, the U.S Environmental Protection Agency (EPA) has deleted over 360 sites (as of March, 2012), including some that have reported achieving restoration goals for groundwater, usually defined as drinking water standards. Other regulatory programs at both the federal and state level report closures of many sites with contaminated groundwater, although "closure" is often defined by site-specific conditions, such as the need for long-term institutional controls. Such trends and financial pressures have prompted the DoD to set very aggressive goals for significantly reducing the expenditures for the Installation Restoration Program within the next few years.

There is general agreement among practicing remediation professionals, however, that there is a substantial population of sites, where, due to inherent geologic complexities, restoration within the next 50-100 years is likely not achievable. Reaching agreement on which sites should be included in this category, and what should be done with such sites, however, has proven to be difficult. EPA recently summarized the agency's recommended decision guidance

(July, 2011) for these more complex sites, presenting a Road Map for groundwater restoration that targets both Superfund and RCRA Corrective Action sites. A key decision in that Road Map is determining whether or not restoration of groundwater is "likely." If not, alternative strategies must be evaluated to achieve the remedial action objectives, including possible modification of these objectives or the points of compliance. The National Research Council (NRC) has also addressed the issue of complex and difficult sites. Since 1987, there have been at least six NRC studies to evaluate barriers to achieving the goal of groundwater restoration. These reports addressed both technical and institutional barriers to restoration, but in general, the reports have concluded that some fraction of sites will require containment and long-term management and the number of such sites could be in the thousands. Other organizations have also undertaken in-depth assessments of barriers to restoration at more complex sites including the Interstate Technology Regulatory Commission (ITRC).

In this context, the U.S. Army Environmental Command (AEC) agreed to support a NRC study to address the technical and management issues arising from barriers to restoration of contaminated groundwater at these complex sites. In particular, the AEC was concerned that delays in decision making on the final remedies at many of their more complex sites could diminish their ability to achieve DoD goals for the IRP. For the Army, one significant goal is achieving the RIP or RC milestones for 100 percent of their IRP sites at active installations by 2014. This study was established under the Water Science and Technology Board (WSTB) of the NRC with the title "Future Options for Management in the Nation's Subsurface Remediation Effort." The Committee included fifteen individuals representing expertise in all areas relevant to the SOT, including various scientific and technical disciplines, resource economics, environmental policy, risk assessment and public stakeholder issues. Seven meetings were held over the past two years, with presentations from a wide range of interested parties. I would like to thank the following individuals for giving presentations to the committee during one or more of its meetings: Laurie Haines-Eklund, Army Environmental Command; Jim Cummings, EPA Superfund Office; Adam Klinger, EPA Underground Storage Tank Office; Jeff Marquesee and Andrea Leeson, SERDP; Brian Looney, DOE Environmental Management; John Gillespie, Air Force Center for Environmental Excellence; Anna Willett, Interstate Technology and Regulatory Council; Alan Robeson, American Water Works Association; Jill Van Dyke, National Groundwater Association; Ira May, May Geoenvironmental Services; Roy Herndon, Orange County Water District; Milad Taghavi, LADWP; Carol Williams, San Gabriel Supply; Gil Borboa, City of Santa Monica; David Lazerwitz, Farella Braun + Martel, LLP; James Giannopoulos, California State Water Quality Control Board; Herb Levine, EPA Region 9; Alec Naugle, CA Region 2 Water Board; David Sweeney, New Jersey Department of Environmental Protection; Rula Deeb, Malcolm Pirnie; Amy Edwards, Holland & Knight LLP; Brian Lynch, Marsh Environmental Practice; Richard Davies, Chartis; Henry Schuver and Helen Dawson, EPA; Tushar Talele, Arcadis; Anura Jayasumana, Colorado School of Mines; Deborah Morefield, Office of the Deputy Undersecretary of Defense; Alana Lee, EPA Region 9; Betsy Southerland and Matt Charsky, EPA; Mike Truex, Pacific National Lab; and Jim Gillie, Versar/Joint Base Lewis McChord.

I wish to acknowledge the herculean efforts of Laura Ehlers and her colleagues at the WSTB for organizing our meetings, managing multiple tasks, and finally completing the editing of contributions from committee members, a task that requires both editing and substantial technical expertise and diplomacy in helping a diverse committee reach consensus. I am indebted to Laura for her efforts on completing this report. I also want to send special thanks to all the Committee members who so diligently participated in long sessions at our meetings, produced comprehensive summaries of the state of the science in subsurface remediation, and who wrestled with the complexities of addressing the challenges of better decision making. The contributions of those who worked on the final chapter are especially appreciated, and particularly those individuals who joined the committee later in deliberations to fill in for vacancies caused by unanticipated changes in the committee roster.

This report has been reviewed in draft form by individuals chosen for their diverse perspectives and technical expertise, in accordance with procedures approved by the National Research Council's Report Review Committee. The purpose of this independent review is to provide candid and critical comments that will assist the institution in making its published report as sound as possible and to ensure that the report meets institutional standards for objectivity, evidence, and responsiveness to the study charge. The review comments and draft manuscript remain confidential to protect the integrity of the deliberative process. We wish to thank the following individuals for their review of this report: Lisa Alvarez-Cohen, University of California, Berkeley; Linda Lee, Purdue University; Jacqueline MacDonald Gibson, University of North Carolina, Chapel Hill; David Nakles, Carnegie Mellon University; Stavros Papadopulos, S.S. Papadopulos & Associates, Inc.; Tom Sale, Colorado State University; Rosalind Schoof, Environ International Corporation; Hans Stroo, HydroGeoLogic, Inc.; and Marcia E. Williams, Gnarus Advisors, LLC.

Although the reviewers listed above have provided many constructive comments and suggestions, they were not asked to endorse the conclusions or recommendations nor did they see the final draft of the report before its release. The review of this report was overseen by Susan L. Brantley, Pennsylvania State University; and Mitchell Small, Carnegie Mellon University. Appointed by the National Research Council, they were responsible for making certain that an independent examination of this report was carried out in accordance with institutional procedures and that all review comments were carefully considered. Responsibility for the final content of this report rests entirely with the authoring committee and the institution.

Michael C. Kavanaugh, Chair
Committee on Future Options for Management in the Nation's Subsurface Remediation Efforts

Contents

June 29, 2011

Office of Groundwater and Drinking Water
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: Comments on Permitting Guidance for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels

Dear Sir or Madam:

Thank you for the opportunity to provide comments on the Environmental Protection Agency's ("EPA") development of UIC Class II permitting guidance for hydraulic fracturing activities that use diesel fuels in fracturing fluids.

The Natural Resources Defense Council ("NRDC") is a national, non-profit legal and scientific organization with 1.3 million members and activists worldwide. Since its founding in 1970, NRDC has been active on a wide range of environmental issues, including fossil fuel extraction and drinking water protection. NRDC is actively engaged in issues surrounding oil and gas development and hydraulic fracturing, particularly in the Rocky Mountain West and Marcellus Shale regions.

Earthjustice is a non-profit public interest law firm originally founded in 1971. Earthjustice works to protect natural resources and the environment, and to defend the right of all people to a healthy environment. Earthjustice is actively addressing threats to air, water, public health and wildlife from oil and gas development and hydraulic fracturing in the Marcellus Shale and Rocky Mountain regions.

Founded in 1892, the Sierra Club works to protect communities, wild places, and the planet itself. With 1.4 million members and activists worldwide, the Club works to provide healthy communities in which to live, smart energy solutions to combat global warming, and an enduring legacy of for America's wild places. The Sierra club is actively addressing the environmental threats to our land, water, air from natural gas extraction across the United States.

General Comments

We appreciate EPA's decision to issue permitting guidance for hydraulic fracturing using diesel fuel. While this practice is regulated under the currently existing UIC Class II regulations, hydraulic fracturing also poses unique risks to USDWs. For that reason, we believe that EPA must promulgate new regulations in addition to permitting guidance. The issuance of permitting guidance under Class II is an important stopgap, but only through regulation that specifically address hydraulic fracturing using diesel can USDWs be adequately protected.

UNPERMITTED INJECTION OF DIESEL FUELS THROUGH HYDRAULIC FRACTURING IS A VIOLATION OF THE SAFE DRINKING WATER ACT

As an initial matter, EPA should use its proposed guidance to reemphasize an important point: the use of diesel fuel injection for hydraulic fracturing is already subject to the requirements of the Safe Drinking Water Act ("SDWA"), whether or not it is specifically addressed by EPA guidance or state UIC programs.

The statutory definition of "underground injection" as "the subsurface emplacement of fluids by well injection" plainly encompasses hydraulic fracturing. 42 U.S.C. § 300h(d)(1); see, e.g., Legal Environmental Assistance Found. v. EPA, 118 F.3d 1467, 1475 (11th Cir. 1997) (holding that the statute requires EPA to regulate hydraulic fracturing operations). SDWA underscores this point by excluding hydraulic fracturing from the definition of "underground injection," except where diesel fuel is used. 42 U.S.C. § 300h(d)(1)(B)(ii). Such an exclusion would be unnecessary if hydraulic fracturing were not otherwise a form of SDWA-regulated underground injection.

Because it represents a form of underground injection, all hydraulic fracturing with diesel fuel violates SDWA unless a permit has been issued. 42 U.S.C. § 300h(b)(1)(A); 40 C.F.R. §§ 144.1(d)(6), (g), 144.11.

Because diesel fuel contains carcinogenic benzene, toluene, ethylene, and xlyene ("BTEX") compounds it poses a major concern.[1] Therefore, when Congress exempted some hydraulic fracturing injections from the Act, it explicitly limited that exemption to wells where fluids "other than diesel fuels" are used. 42 U.S.C. § 300h(d)(1)(B)(ii).[2] For those hydraulic fracturing injections using diesel fuel, the SDWA Class II well program applies. See 40 C.F.R. § 144.6(b).

Nevertheless, many companies have continued to use diesel fuel without obtaining a permit. The minority staff of the House Committee on Energy and Commerce determined that between 2005 and 2009 "oil and gas service companies injected 32.2 million gallons of diesel fuel or hydraulic fracturing fluids containing diesel fuel in wells in 19 states."[3] The investigators determined that "no oil and gas service companies have sought – and no state and federal regulators have issued – permits for diesel fuel use in hydraulic fracturing."[4]

In light of this noncompliance (and assertions of confusion on the part of hydraulic fracturing service companies), EPA should reaffirm that these injections were illegal, and future injections without a permit are also illegal.

EPA should further clarify that these injections were barred under SDWA whether or not they occurred in a state with primacy to enforce SDWA, and whether or not such states had rules on the books. This is so because the SDWA requires each state to prohibit unpermitted injections. 42 U.S.C. § 300h(b)(1)(A).

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[1] For example, EPA described diesel as the "additive of greatest concern" in hydraulic fracturing operations.US EPA, *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs* (June 2004) at ES-12.
[2] Of course, "[n]otwithstanding any other provision of [the SDWA]," including the hydraulic fracturing exemption, EPA retains its power to act against injection practices which "may present an imminent and substantial endangerment to the health of persons." 42 U.S.C. § 300i(a). EPA could also use this authority to address diesel injection.
[3] Letter from Reps. Waxman, Markey, and DeGette to EPA Administrator Lisa Jackson (Jan. 31, 2001) at 1.
[4] *Id.*; *see also* Dusty Horwitt, Environmental Working Group, *Drilling Around the Law* (2009) at 12-13 (documenting state and federal agency officials' failure to regulate these injections).

The statute leaves no room for states to simply ignore illegal injections to which the Act applies. Moreover, the SDWA regulations provide that each state program "must be administered in accordance" with various federal regulations, including 40 C.F.R. § 144.11, which prohibits "[a]ny underground injection, except into a well authorized by rule or except as authorized by permit." 40 C.F.R. § 145.11(a)(5). Thus, even if a state's rules do not explicitly address hydraulic fracturing injections with diesel fuel, the Class II permitting rules remain in place and govern all such injections.[5]

As the Congressional investigation demonstrates, oil and gas companies ignored these clear requirements.[6] In light of this apparently common failure to comply with the law, EPA would be well within its authority to ban diesel injection entirely. Diesel fuel injection is an inherent threat to safe drinking water. Cf. 42 U.S.C. § 300h(b)(1)(B) (applicants for permits must satisfactorily demonstrate that "the underground injection will not endanger drinking water sources"). Companies can and should be required to avoid using diesel fuel in their operations. But if EPA does not do so, it should at a minimum limit the threats it poses by issuing strong guidance and requiring permits to control injection practices.

Responses to EPA's Discussion Questions

WHAT SHOULD BE CONSIDERED AS "DIESEL FUELS?

The injection of any quantity of diesel fuels for hydraulic fracturing should be covered under EPA's UIC Class II regulations. This includes products derived from, containing, or mixed with diesel fuels or any fuel which could be used in a diesel engine.

At 40 CFR §80.2(x), "diesel fuel" is defined as:

Diesel fuel means any fuel sold in any State or Territory of the United States and suitable for use in diesel engines, and that is—

(1) A distillate fuel commonly or commercially known or sold as No. 1 diesel fuel or No. 2 diesel fuel;

(2) A non-distillate fuel other than residual fuel with comparable physical and chemical properties (e.g. , biodiesel fuel); or

(3) A mixture of fuels meeting the criteria of paragraphs (1) and (2) of this definition.

WHAT WELL CONSTRUCTION REQUIREMENTS SHOULD APPLY TO HF WELLS USING DIESEL FUELS?

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[5] States which do not enforce against scofflaw injectors risk their primacy, as EPA should make clear. *See* 42 U.S.C. § 300h(c) (providing that if EPA determines that "a state no longer meetings the requirements" of the SDWA, then EPA shall implement a federal program).

[6] Indeed, even diesel injection into wells permitted by rule is barred if the operator did not comply with the Class II regulations. These applicable rules include EPA's inventory requirements at 40 C.F.R. § 144.26, which trigger reporting of well location and operating status, and, for EPA-administered programs, reports on the "nature of injected fluids" and on the mechanical integrity of the well. *See* 40 C.F.R. § 144.22(prohibiting injection without inventory reporting). If operators inject into permitted-by-rule wells without complying with these and other applicable requirements, they further violate the SDWA.

Casing and Cement

Proper well construction is crucial to ensuring protection of USDWs. The first step to ensuring good well construction is ensuring proper well drilling techniques are used. This includes appropriate drilling fluid selection, to ensure that the wellbore will be properly conditioned and to minimize borehole breakouts and rugosity that may complicate casing and cementing operations. Geologic, engineering, and drilling data can provide indications of potential complications to achieving good well construction, such as highly porous or fractured intervals, lost circulation events, abnormally pressured zones, or drilling "kicks" or "shows." These must be accounted for in designing and implementing the casing and cementing program. Reviewing data from offset wellbores can be helpful in anticipating and mitigating potential drilling and construction problems. Additionally, proper wellbore cleaning and conditioning techniques must be used to remove drilling mud and ensure good cement placement.

Hydraulic fracturing requires fluid to be injected into the well at high pressure and therefore wells must be appropriately designed and constructed to withstand this pressure. The casing and cementing program must:

- Properly control formation pressures and fluids
- Prevent the direct or indirect release of fluids from any stratum to the surface
- Prevent communication between separate hydrocarbon-bearing strata
- Protect freshwater aquifers/useable water from contamination
- Support unconsolidated sediments
- Protect and/or isolate lost circulation zones, abnormally pressured zones, and any prospectively valuable mineral deposits

Casing must be designed to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; corrosion; erosion; and hydraulic fracturing pressure. The casing design must include safety measures that ensure well control during drilling and completion and safe operations during the life of the well.

UIC Class II rules require that injection wells be cased and cemented to prevent movement of fluids into or between underground sources of drinking water and that the casing and cement be designed for the life of the well [40 CFR §146.22(b)(1)]. Achieving and maintaining mechanical integrity are crucial to ensuring these requirements. Operators must demonstrate that wells will be designed and constructed to ensure both internal and external mechanical integrity. Internal mechanical integrity refers to the absence of leakage pathways through the casing; external mechanical integrity refers to the absence of leakage pathways outside the casing, primarily through the cement.

The components of a well that ensure the protection and isolation of USDWs are steel casing and cement. Multiple strings of casing are used in the construction of oil and gas wells, including: conductor casing, surface casing, production casing, and potentially intermediate casing. For all casing strings, the design and construction should be based on Good Engineering Practices (GEP), Best Available Technology (BAT), and local and regional engineering and geologic data. All well construction materials must be compatible with fluids with which they may come into contact and be resistant to corrosion, erosion, swelling, or degradation that may result from such contact.

Conductor Casing:

Conductor casing is typically the first piece of casing installed and provides structural integrity and a conduit for fluids to drill the next section of the well. Setting depth is based on local geologic and engineering factors but is generally relatively shallow, typically down to bedrock. Depending on local conditions, conductor casing can either be driven into the ground or a hole drilled and the casing lowered into the hole. In the case where a hole is excavated, the space between the casing and the wellbore – the annulus – should be fully cemented from the base, or "shoe," of the casing to the ground surface, a practice referred to as "cementing to surface." A cement pad should also be constructed around the conductor casing to prevent the downward migration of fluids and contaminants.

Surface Casing:

Surface casing is used to: isolate and protect groundwater from drilling fluids, hydrocarbons, formation fluids, and other contaminants; provide a stable foundation for blowout prevention equipment; and provide a conduit for drilling fluids to drill the next section of the well.

Surface casing setting depth must be based on relevant engineering and geologic factors, but generally should be:

1. Shallower than any pressurized hydrocarbon-bearing zones
2. 100 feet below the deepest USDW

Surface casing must be fully cemented to surface by the pump and plug method. If cement returns are not observed at the surface, remedial cementing must be performed to cement the casing from the top of cement to the ground surface. If shallow hydrocarbon-bearing zones are encountered when drilling the surface casing portion of the hole, operators must notify regulators and take appropriate steps to ensure protection of USDWs.

Intermediate Casing:

Depending on local geologic and engineering factors, one or more strings of intermediate casing may be required. This will depend on factors including but not limited to the depth of the well, the presence of hydrocarbon-or fluid-bearing formations, abnormally pressured zones, lost circulation zones, or other drilling hazards. When used, intermediate casing should be fully cemented from the shoe to the surface by the pump and plug method. Where this is not possible or practical, the cement must extend from the casing shoe to 600 feet above the top of the shallowest zone to be isolated (e.g. productive zone, abnormally pressured zone, etc). Where the distance between the casing shoe and shallowest zone to be isolated makes this technically infeasible, multi-stage cementing must be used to isolate any hydrocarbon- or fluid-bearing formations or abnormally pressured zones and prevent the movement of fluids.

Production Casing:

To be most protective, one long-string production casing (i.e. casing that extends from the total depth of the well to the surface) should be used. This is preferable to the use of a production liner – in which the casing does not extend to surface but is instead “hung” off an intermediate string of casing – as it provides an additional barrier to protect groundwater. The cementing requirements are the same as for intermediate casing.

Production Liner:
If production liner is used instead of long-string casing, the top of the liner must be hung at least 200 feet above previous casing shoe. The cementing requirements for production liners should be the same as for intermediate and production casing.

General:
For surface, intermediate, and production casing, a sufficient number of casing centralizers must be used to ensure that the casing is centered in the hole and in accordance with API Spec 10D (Specification for Bow-Spring Casing Centralizers) and API RP 10D-2 (Recommended Practice for Centralizer Placement and Stop Collar Testing). This is necessary to ensure that the cement is distributed evenly around the casing and is particularly important for directional and horizontal wells. In deviated wells, the casing will rest on the low side of the wellbore if not properly centralized, resulting in gaps in the cement sheath where the casing makes direct contact with the rock. Casing collars should have a minimum clearance of 0.5 inch on all sides to ensure a uniformly concentric cement sheath.

For any section of the well drilled through fresh water-bearing formations, drilling fluids must be limited to air, fresh water, or fresh water based mud and exclude the use of synthetic or oil-based mud or other chemicals. This typically applies to the surface casing and possibly conductor casing portions of the hole.

As recommended in API Guidance Document HF1: Hydraulic Fracturing Operations--Well Construction and Integrity Guidelines, all surface, intermediate, and production casing strings should be pressure tested. Drilling may not be resumed until a satisfactory pressure test is obtained. Casing must be pressure tested to a minimum of 0.22 psi/foot of casing string length or 1500 psi, whichever is greater, but not to exceed 70% of the minimum internal yield. If the pressure declines more than 10% in a 30-minute test or if there are other indications of a leak, corrective action must be taken.

Cement compressive strength tests must be performed on all surface, intermediate, and production casing strings. Casing must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi. The cement mixture must have a 72-hour compressive strength of at least 1200 psi. Additionally, the API free water separation must average no more than six milliliters per 250 milliliters of cement, tested in accordance with API RP 10B-2.

For cement mixtures without published compressive strength tests, the operator or service company must perform such tests in accordance with the current API RP 10B-6 and provide the results of these tests to regulators prior to the cementing operation. The test temperature must be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of cement. A better quality of cement may be required where local conditions make it necessary to prevent pollution or provide safer operating conditions.

As recommended in API Guidance Document HF1: Hydraulic Fracturing Operations--Well Construction and Integrity Guidelines, casing shoe tests should be performed immediately after drilling out of the surface or intermediate casing. These may include Formation Integrity Tests (FIT), Leak-Off Tests (LOT or XLOT), and pressure fall-off or pump tests. Casing shoe tests are used to ensure casing and cement integrity, determine whether the formations below the casing shoe can withstand the pressure to which they will be subjected while drilling the next section of the well, and gather data on rock mechanical properties. If any of the casing shoe tests fail, remedial action must be taken to ensure that no migrations pathways exist. Alternatively, the casing and cementing plan may need to be revised to include additional casing strings in order to properly manage pressure.

UIC Class II rules require that cement bond, temperature, or density logs be run after installing surface, intermediate, and production casing and cement [40 CFR §146.22(f)(2)(i)(B)]. Ideally, all three types of logs should be run. The term “cement bond log” refers to out-dated technology and the terms “cement evaluation logs,” “cement integrity logs” or “cement mapping logs” are preferable. Cement integrity and location must be verified using cement evaluation tools that can detect channeling in 360 degrees. A poor cement job, in which the cement contains air pockets or otherwise does not form a complete bond between the rock and casing or between casing strings, can allow fluids to move behind casing from the reservoir into USDWs. Verifying the integrity of the cement job is crucial to ensure no unintended migration of fluids. Traditional bond logs cannot detect the fine scale channeling which may allow fluids to slowly migrate over years or decades and therefore the use of more advanced cement evaluation logs is crucial. (For further reading see, e.g., Lockyear et. al, 1990; Frisch et. al, 2005)

When well construction is completed, the operator should certify, in writing, that the casing and cementing requirements were met for each casing string.

In addition, it may be useful to review the casing and cementing regulations of states with long histories of oil and gas production such as Texas, Alaska, California, and Pennsylvania. Specific examples include:

- Requirements for casing and cementing record keeping for casing and cementing operations in the California Code of Regulations (CCR) at 14 CCR §1724
- Requirements for casing and cementing program application content in the Alaska Administrative Code (AAC) at 20 AAC §25.030(a)
- Cement chemical and physical degradation standard in the Pennsylvania Code (Pa. Code) at 25 Pa. Code §78.85(a)
- Requirement to report and repair defective casing or take the well out of service in the Pennsylvania Code at 25 Pa. Code §78.86
- Casing standard in gas storage areas in the Pennsylvania Code at 25 Pa. Code §78.75, in areas with gas storage
- Casing standard in coal development areas in the Pennsylvania Code at 25 Pa. Code §78.75, in areas with sufficient coal seams
- Casing testing and minimum overlap length standards in the California Code of Regulations at 14 CCR §1722

- Cement quality, testing, and remedial repair standard in the Alaska Administrative Code at 20 AAC §25.030
- Casing quality and amount standard in the Pennsylvania Code at 25 Pa. Code §78.84 and §78.71

Well Logs

After drilling the well but prior to casing and cementing operations, operators must obtain well logs to aid in the geologic, hydrologic, and engineer characterization of the subsurface. Open hole logs, i.e. logs run prior to installing casing and cement, should at a minimum include:

Gamma Ray Logs:
Gamma ray logs detect naturally occurring radiation. These logs are commonly used to determine generic lithology and to correlate subsurface formations. Shale formations have higher proportions of naturally radioactive isotopes than sandstone and carbonate formations. Thus, these formations can be distinguished in the subsurface using gamma ray logs.

Density/Porosity Logs:
Two types of density logs are commonly used: bulk density logs, which are in turn used to calculate density porosity, and neutron porosity logs. While not a direct measure of porosity, these logs can be used to calculate porosity when the formation lithology is known. These logs can be used to determine whether the pore space in the rock is filled with gas or with water.

Resistivity Logs:
These logs are used to measure the electric resistivity, or conversely conductivity, of the formation. Hydrocarbon- and fresh water-bearing formations are resistive, i.e. they cannot carry an electric current. Brine-bearing formations have a low resistivity, i.e. they can carry an electric current. Resistivity logs can therefore be used to help distinguish brine-bearing from hydrocarbon-bearing formations. In combination with Darcy's Law, resistivity logs can be used to calculate water saturation.

Caliper Logs:
Caliper logs are used to determine the diameter and shape of the wellbore. These are crucial in determining the volume of cement that must be used to ensure proper cement placement.

These four logs, run in combination, make up one of the most commonly used logging suites. Additional logs may be desirable to further characterize the formation, including but not limited to Photoelectric Effect, Sonic, Temperature, Spontaneous Potential, Formation Micro-Imaging (FMI), Borehole Seismic, and Nuclear Magnetic Resonance (NMR). The use of these and other logs should be tailored to site-specific needs. (For further reading see, e.g., Asquith and Krygowski, 2004)

UIC Class II rules have specific logging requirements "(f)or surface casing intended to protect underground sources of drinking water in areas where the lithology has not been determined" [40 CFR §146.22(f)(2)(i)]. For such wells, electric and caliper logs must be run before surface casing is installed [40 CFR §146.22(f)(2)(i)(A)]. Such logs should be run on all wells, not just those where lithology has not been determined, and the electric logs suite should include, at a minimum, caliper, resistivity and gamma ray or spontaneous potential logs. For intermediate and long string casing "intended to facilitate injection," UIC Class II rules require that electric porosity, gamma ray, and fracture finder logs be run before casing is installed [40 CFR §146.22(f)(2)(ii)(A) and (B)]. Hydraulic fracturing should be included in the definition of "injection." Operators should also run caliper and resistivity logs. The term "fracture finder logs" refers to out-dated technology. More advanced tools for locating fractures should be used, such as borehole imaging logs (e.g. FMI logs) and borehole seismic.

Core and Fluid Sampling

While not specifically required by current UIC Class II regulations, operators of wells that will be hydraulically fractured using diesel should also obtain whole or sidewall cores of the producing and confining zone(s) and formation fluid samples from the producing zone(s). At a minimum, routine core analysis should be performed on core samples representative of the range of lithology and facies present in the producing and confining zone(s). Special Core Analysis (SCAL) should also be considered, particularly for samples of the confining zone, where detailed knowledge of rock mechanical properties is necessary to determine whether the confining zone can prevent or arrest the propagation of fractures. Operators should also record the fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the producing and confining zone(s). Operators should prepare and submit a detailed report on the physical and chemical characteristics of the producing and confining zone(s) and formation fluids that integrates data obtained from well logs, cores, and fluid samples. This must include the fracture pressure of both the producing and confining zone(s).

WHAT WELL OPERATION, MECHANICAL INTEGRITY, MONITORING, AND REPORTING REQUIREMENTS SHOULD APPLY TO HF WELLS USING DIESEL FUELS?

Mechanical Integrity

Operators must maintain mechanical integrity of wells at all times. Mechanical integrity should be periodically tested by means of a pressure test with liquid or gas, a tracer survey such as oxygen activation logging or radioactive tracers, a temperature or noise log, and a casing inspection log. The frequency of such testing should be based on site and operation specific requirements and be delineated in a testing and monitoring plan prepared, submitted, and implemented by the operator.

Mechanical integrity and annular pressure should be monitored over the life of the well. Instances of sustained casing pressure can indicate potential mechanical integrity issues. The annulus between the production casing and tubing (if used) should be continually monitored. Continuous monitoring allows problems to be identified quickly so repairs may be made in a timely manner, reducing the risk that a wellbore problem will result in contamination of USDWs.

Operations and Monitoring

Each hydraulic fracturing treatment must be modeled using a 3D geologic and reservoir model, as described in the Area of Review requirements, prior to operation to ensure that the treatment will not endanger USDWs. Prior to performing a hydraulic fracturing treatment, operators should perform a pressure fall-off or pump test, injectivity tests, and/or a mini-frac. Data obtained from such tests can be used to refine the hydraulic fracture model, design, and implementation.

The hydraulic fracturing operation must be carefully and continuously monitored. In API Guidance Document HF1, Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines, the

America Petroleum Institute recommends continuous monitoring of surface injection pressure, slurry rate, proppant concentration, fluid rate, and sand or proppant rate.

If at any point during the hydraulic fracturing operation the monitored parameters indicate a loss of mechanical integrity or if injection pressure exceeds the fracture pressure of the confining zone(s), the operation must immediately cease. If either occurs, the operator must notify the regulator within 24 hours and must take all necessary steps to determine the presence or absence of a leak or migration pathways to USDWs. Prior to any further operations, mechanical integrity must be restored and demonstrated to the satisfaction of the regulator and the operator must demonstrate that the ability of the confining zone(s) to prevent the movement of fluids to USDWs has not been compromised. If a loss of mechanical integrity is discovered or if the integrity of the confining zone has been compromised, operators must take all necessary steps to evaluate whether injected fluids or formation fluids may have contaminated or have the potential to contaminate any unauthorized zones. If such an assessment indicates that fluids may have been released into a USDW or any unauthorized zone, operators must notify the regulator within 24 hours, take all necessary steps to characterize the nature and extent of the release, and comply with and implement a remediation plan approved by the regulator. If such contamination occurs in a USDW that serves as a water supply, a notification must be placed in a newspaper available to the potentially affected population and on a publically accessible website and all known users of the water supply must be individually notified immediately by mail and by phone.

Techniques to measure actual fracture growth should be used, including downhole tiltmeters and microseismic monitoring. These techniques can provide both real-time data and, after data processing and interpretation, can be used in post-fracture analysis to inform fracture models and refine hydraulic fracture design. Tiltmeters measure small changes in inclination and provide a measure of rock deformation. Microseismic monitoring uses highly sensitive seismic receivers to measure the very low energy seismic activity generated by hydraulic fracturing (For further reading see, e.g., House, 1987; Maxwell et al., 2002; Le Calvez et al., 2007; Du et al., 2008; Warpinski et al., 2008; Warpinski, 2009; and Cipolla et al. 2011).

Hydraulic fracturing fluid and proppant can sometimes be preferentially taken up by certain intervals or perforations. Tracer surveys and temperature logs can be used to help determine which intervals were treated. Tracers can be either chemical or radioactive and are injected during the hydraulic fracturing operation. After hydraulic fracturing is completed, tools are inserted into the well that can detect the tracer(s). Temperature logs record the differences in temperature between zones that received fracturing fluid, which is injected at ambient surface air temperature, and in-situ formation temperatures, which can be in the hundreds of degrees Fahrenheit.

Operators should develop, submit, and implement a long-term groundwater quality monitoring program. Dedicated water quality monitoring wells should be used to help detect the presence of contaminants prior to their reaching domestic water wells. Placement of such wells should be based on detailed hydrologic flow models and the distribution and number of hydrocarbon wells. Baseline monitoring should begin at least a full year prior to any activity, with monthly or quarterly sampling to characterize seasonal variations in water chemistry. Monitoring should continue a minimum of 5 years prior to plugging and abandonment.

Reporting

At a minimum, operators must report:

- All instances of hydraulic fracturing injection pressure exceeding operating parameters as specified in the permit
- All instances of an indication of loss of mechanical integrity
- Any failure to maintain mechanical integrity
- The results of:
    - Continuous monitoring during hydraulic fracturing operations
    - Techniques used to measure actual fracture growth
    - Any mechanical integrity tests
- The detection of the presence of contaminants pursuant to the groundwater quality monitoring program
- Indications that injected fluids or displaced formation fluids may pose a danger to USDWs
- All spills and leaks
- Any non-compliance with a permit condition

The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a minimum of 30 days prior to a hydraulic fracturing operation:

1. Baseline water quality analyses for all USDWs within the area of review
2. Proposed source, volume, geochemistry, and timing of withdrawal of all base fluids
3. Proposed chemical additives (including proppant coating), reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the proposed concentration or rate and volume percentage of all additives

The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a maximum of 30 days subsequent to a hydraulic fracturing operation:

1. Actual source, volume, geochemistry and timing of withdrawal of all base fluids
2. Actual chemical additives used, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the actual concentration or rate and volume percentage of all additives
3. Geochemical analysis of flowback and produced water, with samples taken at appropriate intervals to determine changes in chemical composition with time and sampled until such time as chemical composition stabilizes

Emergency and Remedial Response

Operators must develop, submit, and implement an emergency response and remedial action plan. The plan must describe the actions the operator will take in response to any emergency that may endanger human life or the environment – including USDWs – such as blowouts, fires, explosions, or leaks and spills of toxic or hazardous chemicals. The plan must include an evaluation of the ability of local resources to respond to such emergencies and, if found insufficient, how emergency response personnel and equipment will be supplemented. Operators should detail what steps they will take to respond to cases of suspected or known water contamination, including notification of users of the water source. The plan must describe what actions will be taken to replace the water supplies of affected individuals in the case of the contamination of a USDW.

The American Petroleum Institute has published recommended practices for developing a Safety and Environmental Management System (SEMS) plan, API Recommended Practice 75L: Guidance Document for the Development of a Safety and Environmental Management System for Onshore Oil and Natural Gas Production Operation and Associated Activities. This may be a useful document to reference when developing guidance.

WHAT SHOULD THE PERMIT DURATION BE AND HOW SHOULD CLASS II PLUGGING AND ABANDONMENT PROVISIONS BE ADDRESSED FOR CLASS II WELLS USING DIESEL FUELS FOR HF?

The permit should be valid for the life of the well. However, operators must request and receive approval prior to performing any hydraulic fracturing operations that occur subsequent to the initial hydraulic fracturing operation for which the permit was approved. This can be accomplished by means of a sundry or amended permit. Operators must provide updates to all relevant permit application data to the regulator.

Prior to plugging and abandoning a well, operators should determine bottom hole pressure and perform a mechanical integrity test to verify that no remedial action is required. Operators should develop and implement a well plugging plan. The plugging plan should be submitted with the permit application and should include the methods that will be used to determine bottom hole pressure and mechanical integrity; the number and type of plugs that will be used; plug setting depths; the type, grade, and quantity of plugging material that will be used; the method for setting the plugs, and; a complete wellbore diagram showing all casing setting depths and the location of cement and any perforations.

Plugging procedures must ensure that hydrocarbons and fluids will not migrate between zones, into USDWs, or to the surface. A cement plug should be placed at the surface casing shoe and extend at least 100 feet above and below the shoe. All hydrocarbon-bearing zones should be permanently sealed with a plug that extends at least 100 feet above and below the top and base of all hydrocarbon-bearing zones. Plugging of a well must include effective segregation of uncased and cased portions of the wellbore to prevent vertical movement of fluid within the wellbore. A continuous cement plug must be placed from at least 100 feet below to 100 feet above the casing shoe. In the case of an open hole completion, any hydrocarbon- or fluid-bearing zones shall be isolated by cement plugs set at the top and bottom of such formations, and that extend at least 100 feet above the top and 100 feet below the bottom of the formation.

At least 60-days prior to plugging, operators must submit a notice of intent to plug and abandon. If any changes have been made to the previously approved plugging plan the operator must also submit a revised plugging plan. No later than 60-days after a plugging operation has been completed, operators must submit a plugging report, certified by the operator and person who performed the plugging operation.

After plugging and abandonment, operators must continue to conduct monitoring and provide financial assurance for an adequate time period, as determined by the regulator, that takes into account site-specific characteristics including but not limited to:

- The results of hydrologic and reservoir modeling that assess the potential for movement of contaminants into USDWs over long time scales.
- Models and data that assess the potential degradation of well components (e.g. casing, cement) over time and implications for mechanical integrity and risks to USDWs.

WHAT SHOULD THE TIME FRAME BE FOR SUBMITTING A PERMIT FOR CLASS II WELLS USING DIESEL FUELS FOR HF?

All operators who wish to drill a Class II well using diesel fuel for hydraulic fracturing must submit a permit application to the regulator. Permit applications should be submitted within a reasonable timeframe but no less than 30 days prior to when the operator intends to begin construction. Under no circumstances shall activity commence until the application is approved and a permit is issued.

WHAT ARE IMPORTANT SITING CONSIDERATIONS?

Site Characterization & Planning

Detailed site characterization and planning and baseline testing prior to any oil and gas development are crucial. Site characterization and planning must take into account cumulative impacts over the life of a project or field.

Operators must submit to the regulator a statistically significant sample, as determined by the regulator, of existing and/or new geochemical analyses of each of the following, within the area of review:

1. Any and all sources of water that serve as USDWs in order to characterize baseline water quality. This data must be made publically available through an online, geographically-based reporting system. The sampling methodology must be based on local and regional hydrologic characteristics such as rates of precipitation and recharge and seasonal fluctuations. At a minimum, characterization must include:
    a. Standard water quality and geochemistry[7]
    b. Stable isotopes
    c. Dissolved gases
    d. Hydrocarbon concentration and composition. If hydrocarbons are present in sufficient quantities for analysis, isotopic composition must be determined

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[7] Including: Turbidity, Specific Conductance, Total Solids, Total Dissolved Solids, pH, Dissolved Oxygen, Redox State, Alkalinity, Calcium, Magnesium, Sodium, Potassium, Sulfate, Chloride, Fluoride, Bromide, Silica, Nitrite, Nitrate + Nitrite, Ammonia, Phosphorous, Total Organic Carbon, Aluminum, Antimony, Arsenic, Barium, Beryllium, Boron, Bromide, Cadmium, Chromium, Cobalt, Copper, Cyanide, Iron, Lead, Manganese, Mercury, Molybdenum, Nickel, Selenium, Silver, Strontium, Thallium, Thorium, Uranium, Vanadium, Zinc, Cryptosporidium, Giardia, Plate Count, Legionella, Total Coliforms, and Organic Chemicals including Volatile Organic Compounds (VOCs)

e. Chemical compounds or constituents thereof, or reaction products that may be introduced by the drilling or hydraulic fracturing process. The use of appropriate marker chemicals is permissible provided that the operator can show scientific justification for the choice of marker(s).

Operators should also consider testing for environmental tracers to determine groundwater age.

2. Any hydrocarbons that may be encountered both vertically and areally throughout the area of review;
3. The producing zone(s) and confining zone(s) and any other intervening zones as determined by the regulator. At a minimum, characterization must include:
    a. Mineralogy
    b. Petrology
    c. Major and trace element bulk geochemistry

Operators of wells that will be hydraulically fractured must demonstrate to the satisfaction of the regulator that the wells will be sited in a location that is geologically suitable. In order to allow the regulator to determine suitability, the owner or operator must provide:

1. A detailed analysis of regional and local geologic stratigraphy and structure including, at a minimum, lithology, geologic facies, faults, fractures, stress regimes, seismicity, and rock mechanical properties.
2. A detailed analysis of regional and local hydrology including, at a minimum, hydrologic flow and transport data and modeling and aquifer hydrodynamics; properties of the producing and confining zone(s); groundwater levels for relevant formations; discharge points, including springs, seeps, streams, and wetlands; recharge rates and primary zones, and; water balance for the area including estimates of recharge, discharge, and pumping
3. A detailed analysis of the cumulative impacts of hydraulic fracturing on the geology of producing and confining zone(s) over the life of the project. This must include, but is not limited to, analyses of changes to conductivity, porosity, and permeability; geochemistry; rock mechanical properties; hydrologic flow; and fracture mechanics.
4. A determination that the geology of the area can be described confidently and that the fate and transport of injected fluids and displaced formation fluids can be accurately predicted through the use of models.

Wells that will be hydraulically fractured must be sited such that a suitable confining zone is present. The operator must demonstrate to the satisfaction of the regulator that the confining zone:

1. Is of sufficient areal extent to prevent the movement of fluids to USDWs, based on the projected lateral extent of hydraulically induced fractures, injected hydraulic fracturing fluids, and displaced formation fluids over the life of the project;
2. Is sufficiently impermeable to prevent the vertical migration of injected hydraulic fracturing fluids or displaced formation fluids over the life of the project;
3. Is free of transmissive faults or fractures that could allow the movement of injected hydraulic fracturing fluids or displaced formation fluids to USDWs; and

4. Contains at least one formation of sufficient thickness and with lithologic and stress characteristics capable of preventing or arresting vertical propagation of fractures.
5. The regulator may require operators of wells that will be hydraulically fractured to identify and characterize additional zones that will impede or contain vertical fluid movement.

The site characterization and planning data listed above does not have to be submitted with each individual well application as long as such data is kept on file with the appropriate regulator and the well for which a permit is being sought falls within the designated area of review.

WHAT SUGGESTIONS DO YOU HAVE FOR REVIEWING THE AREA AROUND THE WELL TO ENSURE THERE ARE NO CONDUITS FOR FLUID MIGRATION, SEISMICITY, ETC.?

The area of review should be the region around a well or group of wells that will be hydraulically fractured where USDWs may be endangered. It should be delineated based on 3D geologic and reservoir modeling that accounts for the physical and chemical extent of hydraulically induced fractures, injected hydraulic fracturing fluids and proppant, and displaced formation fluids and must be based on the life of the project. The physical extent would be defined by the modeled length and height of the fractures, horizontal and vertical penetration of hydraulic fracturing fluids and proppant, and horizontal and vertical extent of the displaced formation fluids. The chemical extent would be defined by that volume of rock in which chemical reactions between the formation, hydrocarbons, formation fluids, or injected fluids may occur, and should take into account potential migration of fluids over time.

The model must take into account all relevant geologic and engineering information including but not limited to:

1. Rock mechanical properties, geochemistry of the producing and confining zone, and anticipated hydraulic fracturing pressures, rates, and volumes.
2. Geologic and engineering heterogeneities
3. Potential for migration of injected and formation fluids through faults, fractures, and manmade penetrations.
4. Cumulative impacts over the life of the project.

As actual data and measurements become available, the model must be updated and history matched. Operators must develop, submit, and implement a plan to delineate the area of review. The plan should include the time frame under which the delineation will be reevaluated, including those operational or monitoring conditions that would trigger such a reevaluation.

Within the area of review, operators must identify all wells that penetrate the producing and confining zones and provide a description of each well’s type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the regulator may require. If any the wells identified are improperly constructed, completed, plugged, or abandoned, corrective action must be taken to ensure that they will not become conduits for injected or formation fluids to USDWs. Operators must develop, submit, and implement a corrective action plan.

WHAT INFORMATION SHOULD BE SUBMITTED WITH THE PERMIT APPLICATION?

In addition to the requirements at 40 CFR §146.24, operators should also submit the following information:

1. Information on the geologic structure, stratigraphy, and hydrogeologic properties of the proposed producing formation(s) and confining zone(s), consistent with Site Characterization and Planning requirements, including:
    a. Maps and cross-sections of the area of review
    b. The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not provide migration pathways for injected fluids or displaced formation fluids to USDWs
    c. Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the producing and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions
    d. Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the producing and confining zone(s)
    e. Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not affect the integrity of the confining zone(s)
    f. Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area
    g. Hydrologic flow and transport data and modeling
2. A list of all wells within the area of review that penetrate the producing or confining zone and a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the regulator may require.
3. Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known
4. Baseline geochemical analyses of USDWs, hydrocarbons, and the producing and confining zone, consistent with the requirements for Site Characterization & Planning
5. Proposed area of review and corrective action plan that meet the Area of Review and Corrective Action Plan requirements
6. A demonstration that the operator has met the financial responsibility requirements
7. Proposed pre-hydraulic fracturing formation testing program to analyze the physical and chemical characteristics of the producing and confining zone(s), that meet the Well Log, Core, Fluid Sampling, and Testing requirements
8. Well construction procedures that meet the Well Construction requirements
9. Proposed operating data for the hydraulic fracturing operation:
    a. Operating procedure
    b. Calculated fracture gradient of the producing and confining zone(s)

   c. Maximum pressure, rate, and volume of injected fluids and proppant and demonstration that the proposed hydraulic fracturing operation will not initiate fractures in the confining zone or cause the movement of hydraulic fracturing or formation fluids that endangers a USDW
10. Proposed chemical additives:
    a. Service companies and operators must report all proposed additives by their type (e.g. breaker, corrosion inhibitor, proppant, etc), chemical compound or constituents, and Chemical Abstracts Service (CAS) number
    b. Service companies and operators must report the proposed concentration or rate and volume percentage of all additives
11. Proposed testing and monitoring plan that meets the testing and monitoring plan requirements
12. Proposed well plugging plan that meets the plugging plan requirements
13. Proposed emergency and remedial action plan
14. Prior to granting final approval for a hydraulic fracturing operation, the regulator should consider the following information:
    a. The final area of review based on modeling and using data obtained from the logging, sampling, and testing procedures
    b. Any updates to the determination of geologic suitability of the site and presence of an appropriate confining zone based on data obtained from the logging, sampling, and testing procedures
    c. Information on potential chemical and physical interactions and resulting changes to geologic properties of the producing and confining zone(s) due to hydraulic fractures and the interaction of the formations, formation fluids, and hydraulic fracturing fluids, based on data obtained from the logging, sampling, and testing procedures
    d. The results of the logging, sampling, and testing requirements
    e. Final well construction procedures that meet the well construction requirements
    f. Status of corrective action on the wells in the area of review
    g. A demonstration of mechanical integrity
    h. Any updates to any aspect of the plan resulting from data obtained from the logging, sampling, and testing requirements.

HOW COULD CLASS II FINANCIAL RESPONSIBILITY REQUIREMENTS BE MET FOR WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

Operators must demonstrate and maintain financial responsibility by means of a bond, letter of credit, insurance, escrow account, trust fund, or some combination of these financial mechanisms or any other mechanism approved by the regulator. The financial responsibility mechanism must cover the cost of corrective action, well plugging and abandonment, emergency and remedial response, long term monitoring, and any clean up action that may be necessary as a result of contamination of a USDW.

WHAT PUBLIC NOTIFICATION REQUIREMENTS OR SPECIAL ENVIRONMENTAL JUSTICE CONSIDERATIONS SHOULD BE CONSIDERED FOR AUTHORIZATION OF WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

EPA must ensure that there are opportunities for public involvement and community engagement throughout all steps of the process.

1. The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a minimum of 30 days prior to a hydraulic fracturing operation:
    a. Baseline water quality analyses for all USDWs within the area of review
    b. Proposed source, volume, geochemistry, and timing of withdrawal of all base fluids
    c. Proposed chemical additives, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the proposed concentration or rate and volume percentage of all additives
2. The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a maximum of 30 days subsequent to a hydraulic fracturing operation:
    a. Actual source, volume, geochemistry and timing of withdrawal of all base fluids
    b. Actual chemical additives, reported by their type, chemical compound or constituents, and Chemical Abstracts Service (CAS) number; and the actual concentration or rate and volume percentage of all additives
    c. Geochemical analysis of flowback and produced water, with samples taken at appropriate intervals to determine changes in chemical composition with time and sampled until such time as chemical composition stabilizes

WHAT ARE EFFICIENT ALTERNATIVES TO AUTHORIZE/PERMIT CLASS II WELLS USING DIESEL FUELS FOR HYDRAULIC FRACTURING?

The use of area permits should not be allowed for wells that use diesel fuel for hydraulic fracturing. Each hydraulic fracturing operation is unique and designed for site-and well-specific needs. The fluid volumes required, chemical make-up of hydraulic fracturing fluid, and geology and hydrology of the producing and confining zones can vary from well to well.

In situations where multiple wells will be drilled from the same surface location or pad, it may be permissible to issue a group permit for all such wells. In requesting a group permit, operators must provide the regulator with an analysis demonstrating that the geology, hydrology, and operating parameters of all wells are sufficiently similar such that the issuance of a group permit will not pose increased risks to USDWs as compared to individual permits. If a group permit is approved, operators must still disclose information on injected chemicals for each individual well unless the type and volume of chemicals injected will be identical for each well. Operators must also still provide geochemical analyses of flowback and produced water for each individual well.

Conclusions

Thank you for your consideration of these comments. We are pleased that EPA is undertaking this effort to develop permitting guidance for hydraulic fracturing using diesel fuel. While this guidance is crucial to ensure that no further unpermitted hydraulic fracturing using diesel occurs, we urge EPA to begin the process of drafting new regulation that specifically addresses the unique risks hydraulic fracturing poses to USDWs.

Sincerely,

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ground water

Potential Contaminant Pathways from Hydraulically Fractured Shale to Aquifers

by Tom Myers

Abstract

Hydraulic fracturing of deep shale beds to develop natural gas has caused concern regarding the potential for various forms of water pollution. Two potential pathways—advective transport through bulk media and preferential flow through fractures—could allow the transport of contaminants from the fractured shale to aquifers. There is substantial geologic evidence that natural vertical flow drives contaminants, mostly brine, to near the surface from deep evaporite sources. Interpretative modeling shows that advective transport could require up to tens of thousands of years to move contaminants to the surface, but also that fracking the shale could reduce that transport time to tens or hundreds of years. Conductive faults or fracture zones, as found throughout the Marcellus shale region, could reduce the travel time further. Injection of up to 15,000,000 L of fluid into the shale generates high pressure at the well, which decreases with distance from the well and with time after injection as the fluid advects through the shale. The advection displaces native fluids, mostly brine, and fractures the bulk media widening existing fractures. Simulated pressure returns to pre-injection levels in about 300 d. The overall system requires from 3 to 6 years to reach a new equilibrium reflecting the significant changes caused by fracking the shale, which could allow advective transport to aquifers in less than 10 years. The rapid expansion of hydraulic fracturing requires that monitoring systems be employed to track the movement of contaminants and that gas wells have a reasonable offset from faults.

Introduction

The use of natural gas (NG) in the United States has been increasing, with 53% of new electricity generating capacity between 2007 and 2030 projected to be with NG-fired plants (EIA 2009). Unconventional sources account for a significant proportion of the new NG available to the plants. A specific unconventional source has been deep shale-bed NG, including the Marcellus shale primarily in New York, Pennsylvania, Ohio, and West Virginia (Soeder 2010), which has seen over 4000 wells developed between 2009 and 2010 in Pennsylvania (Figure 1). Unconventional shale-bed NG differs from conventional sources in that the host-formation permeability is so low that gas does not naturally flow in timeframes suitable for development. Hydraulic fracturing (fracking, the industry term for the operation; Kramer 2011) loosens the formation to release the gas and provide pathways for it to move to a well.

Fracking injects up to 17 million liters of fluid consisting of water and additives, including benzene at concentrations up to 560 ppm (Jehn 2011), at pressures up to 69,000 kPa (PADEP 2011) into low permeability shale to force open and connect the fractures. This is often done using horizontal drilling through the middle of the shale with wells more than a kilometer long. The amount of injected fluid that returns to the ground surface after fracking ranges from 9% to 34% of the injected fluid (Alleman 2011; NYDEC 2009), although some would be formation water.

Many agency reports and legal citations (DiGiulio et al. 2011; PADEP 2009; ODNR 2008) and peer-reviewed articles (Osborn et al. 2011; White and Mathes

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Figure 1. Location of Marcellus shale in the northeastern United States. Location of Marcellus wells (dots) drilled from July 2009 to June 2010 and total Marcellus shale wells in New York and West Virginia. There are 4064 wells shown in Pennsylvania, 48 wells in New York, and 1421 wells in West Virginia. Faulting in the area is documented by PBTGS (2001), Isachsen and McKendree (1977), and WVGES (2011, 2010a, 2010b).

2006) have found more gas in water wells near areas being developed for unconventional NG, documenting the source can be difficult. One reason for the difficulty is the different sources; thermogenic gas is formed by compression and heat at depth and bacteriogenic gas is formed by bacteria breaking down organic material (Schoell 1980). The source can be distinguished based on both C and H isotopes and the ratio of methane to higher chain gases (Osborn and McIntosh 2010; Breen et al. 2007). Thermogenic gas can reach aquifers only by leaking from the well bore or by seeping vertically from the source. In either case, the gas must flow through potentially very thick sequences of sedimentary rock to reach the aquifers. Many studies which have found thermogenic gas in water wells found more gas near fracture zones (DiGiulio et al. 2011; Osborn et al. 2011; Breen et al. 2007), suggesting that fractures are pathways for gas transport.

A pathway for gas would also be a pathway for fluids and contaminants to advect from the fractured shale to the surface, although the transport time would be longer. Fracking fluid has been found in aquifers (DiGiulio et al. 2011; EPA 1987), although the exact source and pathways had not been determined. With the increasing development of unconventional NG sources, the risk to aquifers could be increasing. With so little data concerning the movement of contaminants along pathways from depth, either from wellbores or from deep formations, to aquifers, conceptual analyses are an alternative means to consider the risks.

The intent of this study is to characterize the risk factors associated with vertical contaminant transport from the shale to near-surface aquifers through natural pathways. I consider first the potential pathways for contaminant transport through bedrock and the necessary conditions for such transport to occur. Second, I estimate contaminant travel times through the potential pathways, with a bound on these estimates based on formation hydrologic parameters, using interpretative MODFLOW-2000 (Harbaugh et al. 2000) computations. The modeling does not, and cannot, account for all of the complexities of the geology, which could either increase or decrease the travel times compared to those considered herein. The article also does not include improperly abandoned boreholes which could cause rapid transport in addition to natural pathways.

Method of Analysis

Using the Marcellus shale region of southern New York (Figure 1), I consider several potential scenarios of transport from shale, 1500 m below ground surface (bgs) to the surface, beginning with pre-development steady state conditions to establish a baseline and then scenarios considering transport after fracking has potentially caused contaminants to reach formations above the shale. To develop the conceptual models and MODFLOW-2000 simulations, it is necessary first to consider the hydrogeology of the shale and the details of hydraulic fracturing, including details of how fracking changes the shale hydrogeologic properties.

Hydrogeology of Marcellus Shale

Shale is a mudstone, a sedimentary rock consisting primarily of clay- and silt-sized particles. It forms through the deposition of fine particles in a low energy environment, such as a lake- or seabed. The Marcellus shale formed in very deep offshore conditions during Devonian time (Harper 1999) where only the finest particles had remained suspended. The depth to the Marcellus shale varies to as much as 3000 m in parts of Pennsylvania, and averages about 1500 m in southern New York (Soeder 2010). Between the shale and the ground surface are layers of sedimentary rock, including sandstone, siltstone, and shale (NYDEC 2009).

Marcellus shale has very low natural intrinsic permeability, on the order of 10^{-16} Darcies (Kwon et al. 2004a, 2004b; Neuzil 1986, 1994). Schulze-Makuch et al. (1999) described Devonian shale of the Appalachian Basin, of which the Marcellus is a major part, as containing "coaly organic material and appear either gray or black" and being "composed mainly of tiny quartz grains <0.005 mm diameter with sheets of thin clay flakes." Median particle size is 0.0069 ± 0.00141 mm with a grain size distribution of $<2\%$ sand, 73% silt, and 25% clay. Primary pores are typically 5×10^{-5} mm in diameter, matrix porosity is typically 1% to 4.5% and fracture porosity is typically 7.8% to 9% (Schulze-Makuch et al. 1999 and references therein).

Porous flow in unfractured shale is negligible due to the low bulk media permeability, but at larger scales fractures control and may allow significant flow. The Marcellus shale is fractured by faulting and contains synclines and anticlines that cause tension cracks (Engelder et al. 2009; Nickelsen 1986). It is sufficiently fractured in some places to support water wells just 6 to 10 km from where it is being developed for NG at 2000 m bgs (Loyd and Carswell 1981). Conductivity scale dependency (Schulze-Makuch et al. 1999) may be described as follows:

$$K = Cv^{m}$$

K is hydraulic conductivity (m/s), C is the intercept of a log-log plot of observed K to scale (the K at a sample volume of 1 m^3), v is sample volume (m^3), and m is a scaling exponent determined with log-log regression; for Devonian shale, C equals $10^{-14.3}$, representing the intercept, and m equals 1.08 (Schulze-Makuch et al. 1999). The very low intercept value is a statistical but not geologic outlier because it corresponds with very low permeability values and demonstrates the importance of fracture flow in the system (Schulze-Makuch et al. 1999). Most of their 89 samples were small because the deep shale is not easily tested at a field-scale and no groundwater models have been calibrated for flow through the Marcellus shale. Considering a 1-km square area with 30-m thickness, the Kh would equal 5.96×10^{-7} m/s (0.0515 m/d). This effective K is low and the shale would be an aquitard, but a leaky one.

Contaminant Pathways from Shale to the Surface

Thermogenic NG found in near-surface water wells (Osborn et al. 2011; Breen et al. 2007) demonstrates the potential for vertical transport of gas from depth. Osborn et al. (2011) found systematic circumstantial evidence for higher methane concentrations in wells within 1 km of Marcellus shale gas wells. Potential pathways include advective transport through sedimentary rock, fractures and faults, and abandoned wells or open boreholes. Gas movement through fractures depends on fracture width (Etiope and Martinelli 2002) and is a primary concern for many projects, including carbon sequestration (Annunziatellis et al. 2008) and NG storage (Breen et al. 2007). Open boreholes and improperly sealed water and gas wells can be highly conductive pathways among aquifers (Lacombe et al. 1995; Silliman and Higgins 1990).

Pathways for gas suggest pathways for fluids and contaminants, if there is a gradient. Vertical hydraulic gradients of a up to a few percent, or about 30 m over 1500 m, exist throughout the Marcellus shale region as may be seen in various geothermal developments in New York (TAL 1981). Brine more than a thousand meters above their evaporite source (Dresel and Rose 2010) is evidence of upward movement from depth to the surface. The Marcellus shale, with salinity as high as 350,000 mg/L (Soeder 2010; NYDEC 2009), may be a primary brine source. Relatively uniform brine concentrations over large areas (Williams et al. 1998) suggest widespread advective transport. The transition from brine to freshwater suggests a long-term equilibrium between the upward movement of brine and downward movement of freshwater. Faults, which occur throughout the Marcellus shale region (Figure 1) (Gold 1999), could provide pathways (Konikow 2011; Caine et al. 1996) for more concentrated advective and dispersive transport. Brine concentrating in faults or anticline zones reflects potential preferential pathways (Wunsch 2011; Dresel and Rose 2010; Williams 2010; Williams et al. 1998).

In addition to the natural gradient, buoyancy would provide an additional initial upward push. At TDS equal to 350,000 mg/L, the density at 25 °C is approximately

1290 kg/m^3, or more than 29% higher than freshwater. The upward force would equal the difference in weight between the injected fluid and displaced brine. As an example, if 10,000,000 L does not return to the surface as flowback (Jehn 2011), the difference in mass between the volume of fracking fluid and displaced brine is approximately 3,000,000 kg, which would cause an initial upward force. The density difference would dissipate as the salt concentration in the fracking fluid increases due to diffusion across the boundary between the fluid and the brine.

In just Pennsylvania, more than 180,000 wells had been drilled prior to any requirement for documenting their location (Davies 2011), therefore the location of many wells is unknown and some have probably been improperly abandoned. These pathways connect aquifers through otherwise continuous aquitards; overpressurization of lower aquifers due to injection near the well pathway could cause rapid transport to higher aquifers (Lacombe et al. 1995). In the short fracking period, the region that is overpressurized remains relatively close to the gas well (see modeling analysis below), therefore it should be possible for the driller to locate nearby abandoned wells that could be affected by fracking. This article does not consider the potential contamination although unlocated abandoned wells of all types must be considered a potential and possibly faster source for contamination due to fracking.

Effect of Hydraulic Fracturing on Shale

Fracking increases the permeability of the targeted shale to make extraction of NG economically efficient (Engelder et al. 2009; Arthur et al. 2008). Fracking creates fracture pathways with up to 9.2 million square meters of surface area in the shale accessible to a horizontal well (King 2010; King et al. 2008) and connects natural fractures (Engelder et al. 2009; King et al. 2008). No post-fracking studies that documented hydrologic properties were found while researching this article (there is a lack of information about pre- and post-fracking properties; Schweitzer and Bilgesu 2009), but it is reasonable to assume the K increases significantly because of the newly created and widened fractures.

Fully developed shale typically has wells spaced at about 300-m intervals (Edwards and Weisset 2011; Soeder 2010). Up to eight wells may be drilled from a single well pad (NYDEC 2009; Arthur et al. 2008), although not in a perfect spoke pattern. Reducing by half the effective spacing did not enhance overall productivity (Edwards and Weisset 2011) which indicates that 300-m spacing creates sufficient overlap among fractured zones to assure adequate gas drainage. The properties controlling groundwater flow would therefore be affected over a large area, not just at a single horizontal well or set of wells emanating from a single well pad.

Fracking is not intended to affect surrounding formations, but shale properties vary over short ranges (King 2010; Boyer et al. 2006) and out-of-formation fracking is not uncommon. In the Marcellus shale, out-of-formation fracks have been documented 500 m above the top of the shale (Fisher and Warpinski 2011). These fractures could contact higher conductivity sandstone, natural fractures, or unplugged abandoned wells above the target shale. Also, fluids could reach surrounding formations just because of the volume injected into the shale, which must displace natural fluid, such as the existing brine in the shale.

Analysis of Potential Transport along Pathways

Fracking could cause contaminants to reach overlying formations either by fracking out of formation, connecting fractures in the shale to overlying bedrock, or by simple displacement of fluids from the shale into the overburden. Advective transport, considered as simple particle velocity, will manifest if there is a significant vertical component to the regional hydraulic gradient.

Numerical modeling, completed with the MODF LOW-2000 code (Harbaugh et al. 2000), provides flexibility to consider potential conceptual flow scenarios, but should be considered interpretative (Hill and Tiedeman 2007). The simulation considers the rate of vertical transport of contaminants to near the surface for the different conceptual models, based on an expected, simplified, realistic range of hydrogeologic aquifer parameters.

MODFLOW-2000 is a versatile numerical modeling code, but there is insufficient data regarding the geology and water chemistry between aquifers and the deep shale, such as salinity profiles or data concerning mixing of the brine with fracking fluid, to best use its capabilities. As more data becomes available, it may be useful to consider simulating the added upward force caused by the brine by using the SEAWAT-2000 module (Langevin et al. 2003).

Vertical flow would be perpendicular to the general tendency for sedimentary layers to have higher horizontal than vertical conductivity. Fractures and improperly abandoned wells would provide pathways for much quicker vertical transport than general advective transport. This article considers the fractures as vertical columns with model cells having much higher conductivity than the surrounding bedrock. The cell discretization is fine, so the simulated width of the fracture zones is realistic. Dual porosity modeling (Shoemaker et al. 2008) is not justified because turbulent vertical flow through the fractures is unlikely, except possibly during the actual fracking that causes out-of-formation fractures, a scenario not simulated here. MODFLOW-2000 has a module, MNW (Halford and Hanson 2002), that could simulate rapid transport through open bore holes. MNW should be used in situations where open boreholes or improperly abandoned wells are known or postulated to exist.

The thickness of the formations and fault would affect the simulation, but much less than the several-order-of-magnitude variation possible in the shale properties. The overburden and shale thickness were set equal to 1500 and 30 m, respectively, similar to that observed in southern New York. The estimated travel times are proportional for thicker or thinner sections. The overburden could be predominantly sandstone, with sections of shale, mudstone, and limestone. The vertical fault is assumed to be 6-m thick. The fault is an attempt at considering fracture flow, but the simulation treats the 6-m wide fault zone as homogeneous, which could underestimate the real transport rate in fracture-controlled systems which could be highly affected by dispersion. The simulation also ignores diffusion between the fracture and the adjacent shale matrix (Konikow 2011).

There are five conceptual models of flow and transport of natural and post-fracking transport from the level of the Marcellus shale to the near-surface to consider herein:

1. The natural upward advective flow due to a head drop of 30 m from below the Marcellus shale to the ground surface, considering the variability in both shale and overburden K. This is a steady state solution for upward advection through a 30-m thick shale zone and 1500-m overburden. Table 1 shows the chosen K values for shale and sandstone.
2. Same as number 1, but with a vertical fracture connecting the shale with the surface, created using a high-conductivity zone in a row of cells extending through all from above the shale to the surface. This emulates the conceptual model postulated for flow into the alluvial aquifers near stream channels, the location of which may be controlled by faults (Williams et al. 1998). The fault K varies from 10 to 1000 times the surrounding bulk sandstone K (K_{ss}).
3. This scenario tests the effect of extensive fracturing in the Marcellus shale by increasing the shale K (K_{sh}) from 10 to 1000 times its native value over an extensive area. This transient solution starts with initial conditions being a steady state solution from scenario 1. The K_{sh} increases from 10 to 1000 times at the beginning of the simulation, to represent the relatively instantaneous change on the regional shale hydrogeology imposed by the fracking. The simulation estimates both the changes in flux and the time for the system to reach equilibrium.
4. As number 3, considering the effect of the same changes in shale properties but with a fault as in number 2.
5. This scenario simulates the actual injection of 13 to 17 million liters of fluid in 5 d into fractured shale from a horizontal well with and without a fault.

Table 1
Sandstone (ss) and Shale (sh) Conductivity (K) (m/d) and the Steady State Flux (m^3/d) for Model 1 Scenarios

Flux	K_{ss}	K_{sh}
1.7	0.1	0.00001
1.8	0.5	0.00001
1.9	1	0.00001
1.9	5	0.00001
2.0	10	0.00001
2.0	50	0.00001
2.0	100	0.00001
1.7	0.1	0.00001
9.5	0.1	0.00005
19.0	0.1	0.0001
81.2	0.1	0.0005
135.9	0.1	0.001
291.5	0.1	0.005
340.9	0.1	0.01
394.3	0.1	0.05
401.8	0.1	0.1
409.2	0.1	0.5
40.7	0.001	0.1
186.0	0.005	0.1
339.1	0.01	0.1
988.3	0.05	0.1
1297.3	0.1	0.1
1748.0	0.5	0.1
1826.1	1	0.1
1902.8	5	0.1
1915.4	10	0.1
338.3	0.1	0.01
984.1	0.5	0.01
1292.5	1	0.01
1731.5	5	0.01
1816.0	10	0.01
17.4	1	0.0001
86.3	1	0.0005
176.7	1	0.001
775.1	1	0.005
1292.5	1	0.01
2746.8	1	0.05
3183.2	1	0.1
3650.5	1	0.5
3719.9	1	1

Model Setup

The model domain was 150 rows and columns spaced at 3 m to form a 450-m square (Figure 2) with 50 layers bounded with no flow boundaries. The 30-m thick shale was divided into 10 equal thickness layers from layer 40 to 49. The overburden layer thickness varied from 3 m just above the shale to layer 34, 6 m from layer 33 to 29, 9 m from layer 28 to 26, 18 m in layer 25, 30 m from layer 24 to 17, 60 m from layer 16 to 6, 90 m from layer 5 to 3, and 100 m in layers 2 and 1. A 6-m wide column from layer 39 to the surface is added for some scenarios in the center two rows to simulate a higher K fault.

The model simulated vertical flow between constant head boundaries in layers 50 and 1, as a source and sink, so that the overburden and shale properties control the flow. The head in layers 50 and 1 was 1580 and 1550 m, respectively, to create a gradient of 0.019 over the profile. Varying the gradient would have much less effect on transport than changing K over several orders of magnitude and was therefore not done.

Scenario 5 simulates injection using a WELL boundary in layer 44, essentially the middle of the shale, from columns 25 to 125 (Figure 2). It injects 15 million liters over one 5-d stress period, or 3030 m^3/d into 101 model cells at the WELL. The modeled K_{sh} was changed to its

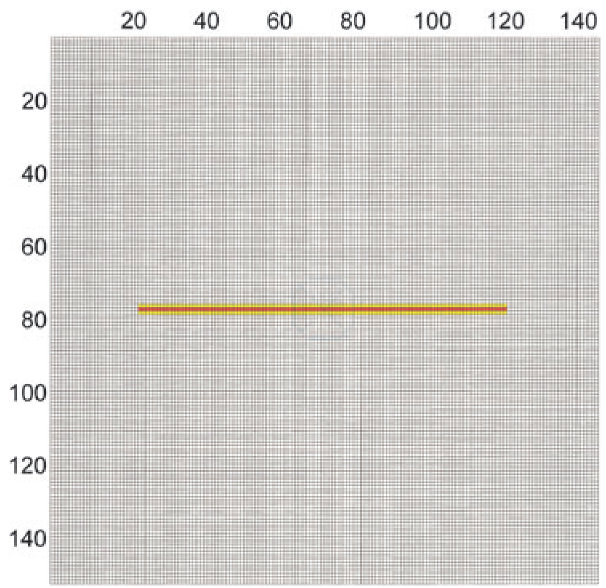

Figure 2. Model grid through layer 44 showing the horizontal injection WELL (red) and DRAIN cells (yellow) used to simulate flowback. There is only one monitoring well because the off-center well is not used in layer 44.

assumed fracked value at the beginning of the simulation. Simulating high rate injection generates very high heads in the model domain, similar to that found simulating oil discharging from the well in the Deepwater Horizon crisis (Hsieh 2011) and water quality changes caused by underground coal gasification (Contractor and El-Didy 1989). DRAIN boundaries on both sides of the WELL simulated return flow for 60 d after the completion of (Figure 2), after which the DRAIN was deactivated. The 60 d were broken into four stress periods, 1, 3, 6, and 50 d long, to simulate the changing heads and flow rates. DRAIN conductance was calibrated so that 20% of the injected volume returned within 60 d to emulate standard industry practice (Alleman 2011; NYDEC 2009). Recovery, continuing relaxation of the head at the well and the adjustment of the head distribution around the domain, occurred during the sixth period which lasted for 36,500 d.

There is no literature guidance to a preferred value for fractured shale storage coefficient, so I estimated S with a sensitivity analysis using scenario 3. With fractured K_{sh} equal to 0.001 m/d, two orders of magnitude higher than the in situ value, the time to equilibrium resulting from simulation tests of three fractured shale storage coefficients, 10^{-3}, 10^{-5}, and 10^{-7}/m, varied twofold (Figure 3). The slowest time to equilibrium was for $S = 10^{-3}$/m (Figure 3), which was chosen for the transient simulations because more water would be stored in the shale and flow above the shale would change the least.

Results

Scenario 1

Table 1 shows the conductivity and flux values for various scenarios. The steady state travel time

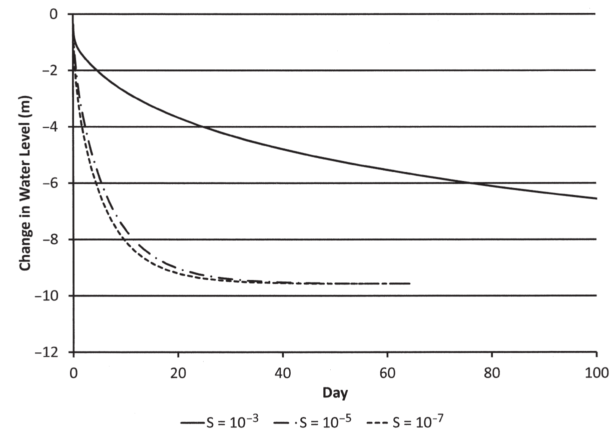

Figure 3. Sensitivity of the modeled head response to the storage coefficient used in the fractured shale for model layer 39 just above the shale.

for a particle through 1500 m of sandstone and shale equilibrates with one of the formations controlling the advection (Figure 4). For example, when the K_{sh} equals 1×10^{-5} m/d, transport time does not vary with K_{ss}. For K_{ss} at 0.1 m/d, transport time for varying K_{sh} ranges from 40,000 to 160 years. The lower travel time estimate is for K_{sh} similar to that found by Schulze-Makuch et al. (1999). The shortest simulated transport time of about 20 years results from both the sandstone and shale K equaling 1 m/d. Other sensitivity scenarios emphasize the control exhibited by one of the media (Figure 4). If K_{sh} is low, travel time is very long and not sensitive to K_{ss}.

Scenario 2

The addition of a fault with K one to two orders of magnitude more conductive than the surrounding sandstone increased the particle travel rate by about 10 times (compare Figure 5 with Figure 4). The fault K controlled the transport rate for K_{sh} less than 0.01 m/d. A highly

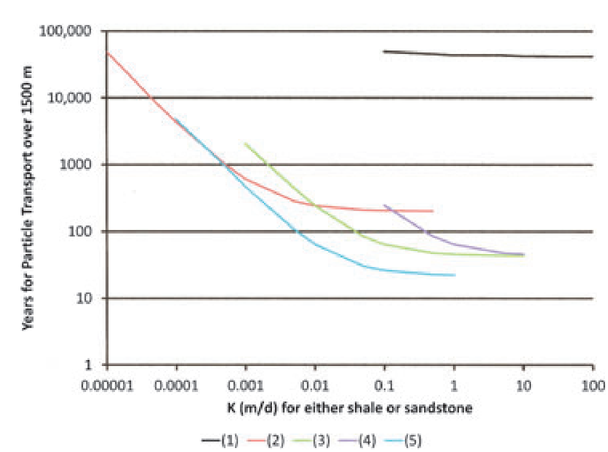

Figure 4. Sensitivity of particle transport time over 1500 m for varying shale and sandstone vertical K. Effective porosity equals 0.1. (1)—varying K_{ss}, $K_{sh} = 10^{-5}$ m/d; (2)—varying K_{ss}, $K_{sh} = 0.1$ m/d; (3)—varying K_{ss}, $K_{sh} = 0.1$ m/d; (4)—varying K_{ss}, $K_{sh} = 0.01$ m/d; and (5)—varying K_{ss}, $K_{sh} = 1.0$ m/d.

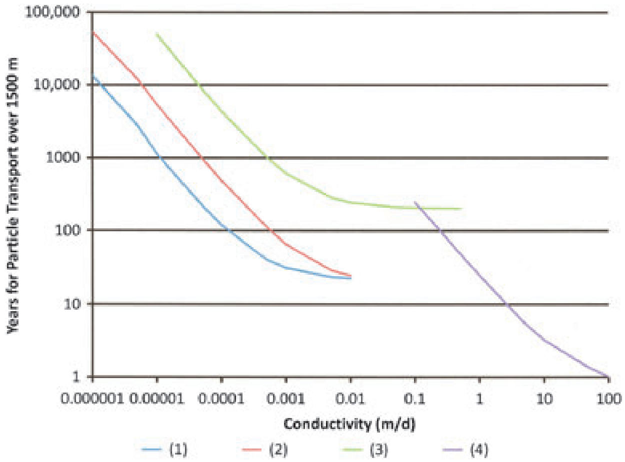

Figure 5. Variability of transport through various scenarios of changing the K for the fault or shale. Effective porosity equals 0.1. (1)—varying K_{sh}, $K_{sh} = 0.01$ m/d; (2)—varying K_{sh}, $K_{sh} = 0.1$ m/d; (3)—no fault; (4)—varying K fault, $K_{sh} = 0.1$ m/d, $K_{sh} = 0.01$ m/d. Unless specified, the vertical fault has $K = 1$ m/d for variable K_{sh}.

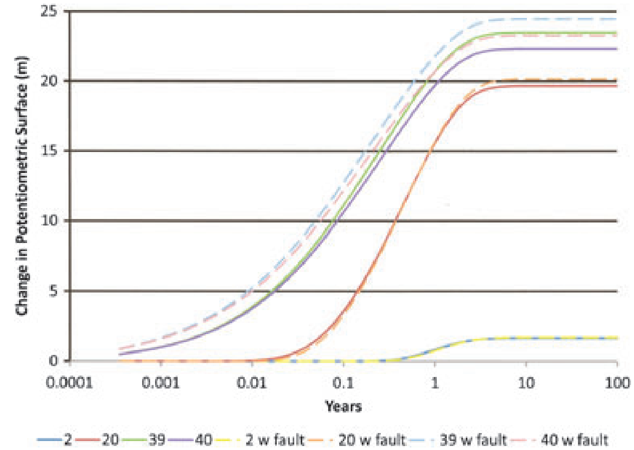

Figure 6. Monitoring well water levels for specified model layers due to fracking of the shale; monitor well in the center of the domain, including in the fault, K of the shale changes from 0.00001 to 0.01 m/d at the beginning of the simulation.

conductive fault could transport fluids to the surface in as little as a year for K_{sh} equal to 0.01 m/d (Figure 5). However, a fault did not significantly change the overall model flux, so with fault values are not shown in Table 1.

Scenarios 3 and 4

Scenarios 3 and 4 estimate the time to establish a new equilibrium once the K_{sh} changes, due to fracking, between values specified in scenarios 1 and 2. Equilibrium times vary by model layer as the changes propagate through the domain, and flux rate for the simulated changes imposed on natural background conditions. The fracking-induced changes cause a significant decrease in the head drop across the shale and the time for adjustment of the potentiometric surface to a new steady state depends on the new shale properties.

The time to equilibrium for one scenario 3 simulation, K_{sh} changing from 10^{-5} to 10^{-2} m/d with K_{ss} equal to 0.1 m/d, varied from 5.5 to 6.5 years, depending on model layer (Figure 6). Near the shale (layers 39 and 40), the potentiometric surface increased from 23 to 25 m reflecting the decreased head drop across the shale. One hundred meters higher, in layer 20, the potentiometric surface increased about 20 m. Simulation of scenario 4, with a fault with $K = 1$ m/d, decreased the time to equilibrium to from 3 to 6 years within the fault zone, depending on model layer (Figure 6). Highly fractured sandstone would allow more vertical transport, but advective flow would also increase so that the base K_{ss} would control the overall rate.

The flux across the upper boundary changed within 100 years for scenario 3 from 1.7 to 345 m^3/d, or 0.000008 to 0.0017 m/d, reflecting control by K_{ss}. There is little difference in the equilibrium fluxes between scenario 3 and 4 indicating that the fault primarily affects the time to equilibrium rather than the long-term flow rate.

Scenario 5: Simulation of Injection

The injection scenarios simulate 15 million liters entering the domain at the horizontal well and the subsequent potentiometric surface and flux changes throughout. The highest potentiometric surface increases (highest injection pressure) occurred at the end of injection (Figure 7), with a 2400 m increase at the horizontal well. The simulated peak pressure both decreased and occurred longer after the cessation of injection with distance from the well (Figures 7 and 8). The pressure at the well returned to within 4 m of pre-injection levels in about 300 d (Figure 7). After injection ceases, the peak pressure simulated further from the well occurs longer from the time of cessation, which indicates there is a pressure divide beyond which fluid continues to flow away from the well bore while within which the fluid flows toward the well bore. The simulated head returned to near pre-injection levels slower with distance from the well (Figure 7), with levels at the edge of the shale (layer 40) and in the near-shale sandstone (layer 39) requiring several hundred days to recover. After recovering from injection, the potentiometric surface above the shale increased in response to flux through the shale adjusting to the change in shale properties (Figure 8), as simulated in scenario 3. The scenario required about 6000 d (16 years) for the potentiometric surface to stabilize at new, higher, levels (Figure 8). Removing the fault from the simulation had little effect on the time to stabilization, and is not shown.

Prior to injection, the steady flux for in situ shale ($K_{sh} = 10^{-5}$ m/d) was generally less than 2 m^3/d and varied little with K_{ss} (Figure 4). Once the shale was fractured, the sandstone controlled the flux which ranges from 38 to 135 m^3/d as K_{ss} ranges from 0.01 to 0.1 m/d (Figure 9), resulting in particle travel times of 2390 and 616 years, respectively. More conductive shale would allow faster transport (Figure 4). Adding a fault to the scenario with K_{ss} equal to 0.01 m/d increased the flux to approximately 63 m^3/d and decreased the particle travel

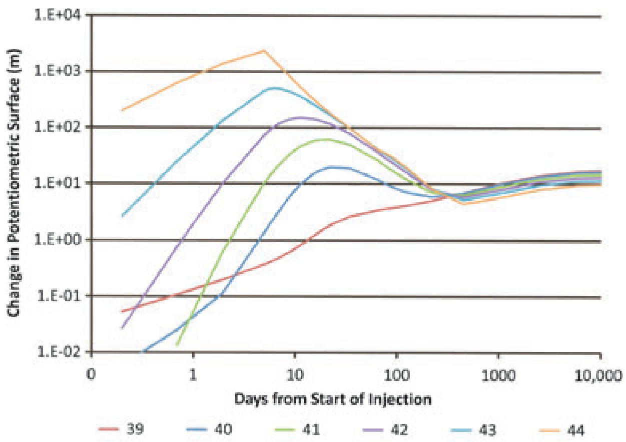

Figure 7. Simulated potentiometric surface changes by layer for specified injection and media properties. The monitoring point is in the center of the domain. Fault is included. K_{sh} = 0.01 m/d, K_{sh} = 0.001 m/d. S (fractured shale) = 0.001/m, S (ss) = 0.0001/m.

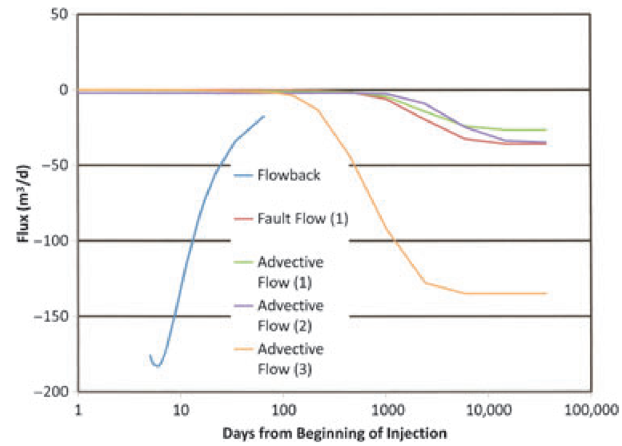

Figure 9. Comparison of flux for three scenarios. Flowback is the same for all scenarios. (1): Kss = 0.01 m/d, Ksh = 0.001 m/d, Fault K = 1 m/d; (2): Kss = 0.01 m/d, Ksh = 0.001 m/d, no fault; (3) Kss = 0.1 m/d, Ksh = 0.001 m/d, no fault.

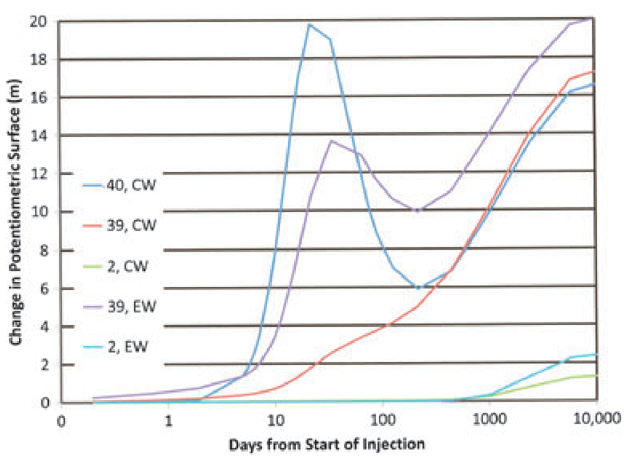

Figure 8. Simulated potentiometric surface changes for layers within the shale and sandstone. CW is center monitoring well and EW is east monitoring well, about 120 m from the centerline. Fault is included. The line for layer 2, CW plots beneath the line for layer 2, EW. K_{ss} = 0.01 m/d, K_{sh} = 0.001 m/d, S (fractured shale) = 0.001/m, S (ss) = 0.0001/m.

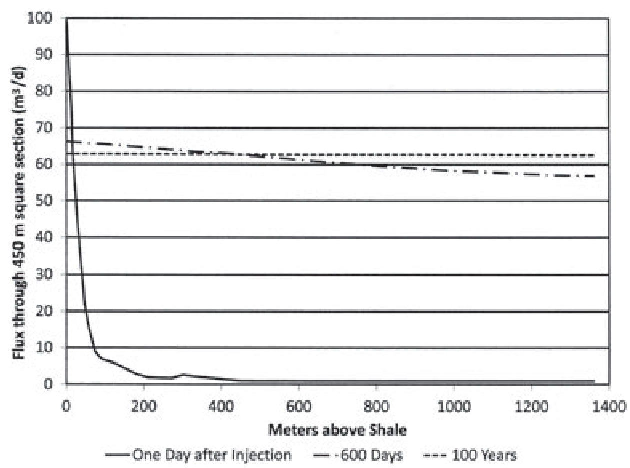

Figure 10. Upward flux across the domain section as a function of distance above the top of the shale layer. Cross section is 202,500 m^2.

time to 31 years. Approximately, 36 m^3/d flowed through the fault (Figure 9). The fault properties control the particle travel time, especially if the fault K is two or more orders of magnitude higher than the sandstone.

Simulated flowback varied little with K_{sh} because it had been calibrated to be 20% of the injection volume. A lower storage coefficient or higher K would allow the injected fluid to move further from the well, which would lead to less flowback.

Vertical flux through the overall section with a fault varies significantly with time, due to the adjustments in potentiometric surface. One day after injection, vertical flux exceeds significantly the pre-injection flux about 200 m above the shale (Figure 10). After 600 d, the vertical flux near the shale is about 68 m^3/d and in layer 2 about 58 m^3/d; it approaches steady state through all sections after 100 years with flux equaling about 62.6 m^3/d. The 100-year flux is 61.5 m^3/d higher than the pre-injection flux because of the changed shale properties.

Discussion

The interpretative modeling completed herein has revealed several facts about fracking. First, MODFLOW can be coded to adequately simulate fracking. Simulated pressures are high, but velocities even near the well do not violate the assumptions for Darcian flow. Second, injection for 5 d causes extremely high pressure within the shale. The pressure decreases with distance from the well. The time to maximum pressure away from the well lags the time of maximum pressure at the well. The pressure drops back to close to its pre-injection level at the well within 300 d, indicating the injection affects the flow for significantly longer periods than just during the fracking operation. Although the times may vary based on media properties, the difference would be at most a month or so, based on the various combinations of properties simulated. The system transitions within 6 years due to changes in the shale properties. The equilibrium transport rate would transition from a system requiring thousands of years to one requiring less than 100 years within less than 10 years.

Third, most of the injected water in the simulation flows vertically rather than horizontally through the shale. This reflects the higher K_{ss} 20 m above the well and the no flow boundary within 225 m laterally from the well, which emulates in situ shale properties that would manifest at some distance in the shale.

Fourth, the interpretative model accurately and realistically simulates long-term steady state flow conditions, with an upward flow that would advect whatever conservative constituents exist at depth. Using low, unfractured K values, the transport simulation may correspond with advective transport over geologic time although there are conditions for which it would occur much more quickly (Figure 4). If the K_{sh} is 0.01 m/d, transport could occur on the order of a few hundreds of years. Faults through the overburden could speed the transport time considerably. Reasonable scenarios presented herein suggest the travel time could be decreased further by an order of magnitude.

Fifth, fracking increases the K_{sh} by several orders of magnitude. Out-of-formation fracking (Fisher and Warpinski 2011) would increase the K in the overburden, thereby changing the regional hydrogeology. Vertical flow could change over broad areas if the expected density of wells in the Marcellus shale region (NYDEC 2009) actually occurs.

Sixth, if newly fractured shale or out-of-formation fractures come close to contacting fault fracture zones, contaminants could reach surface areas in tens of years, or less. Faults can decrease the simulated particle travel time several orders of magnitude.

Conclusion

Fracking can release fluids and contaminants from the shale either by changing the shale and overburden hydrogeology or simply by the injected fluid forcing other fluids out of the shale. The complexities of contaminant transport from hydraulically fractured shale to near-surface aquifers render estimates uncertain, but a range of interpretative simulations suggest that transport times could be decreased from geologic time scales to as few as tens of years. Preferential flow through natural fractures fracking-induced fractures could further decrease the travel times to as little as just a few years.

There is no data to verify either the pre- or post-fracking properties of the shale. The evidence for potential vertical contaminant flow is strong, but there are also almost no monitoring systems that would detect contaminant transport as considered herein. Several improvements could be made.

- Prior to hydraulic fracturing operations, the subsurface should be mapped for the presence of faults and measurement of their properties.
- A reasonable setback distance from the fracking to the faults should be established. The setback distance should be based on a reasonable risk analysis of fracking increasing the pressures within the fault.
- The properties of the shale should be verified, post-fracking, to assess how the hydrogeology will change.
- A system of deep and shallow monitoring wells and piezometers should be established in areas expecting significant development, before that development begins (Williams 2010).

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Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing

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Directional drilling and hydraulic-fracturing technologies are dramatically increasing natural-gas extraction. In aquifers overlying the Marcellus and Utica shale formations of northeastern Pennsylvania and upstate New York, we document systematic evidence for methane contamination of drinking water associated with shale-gas extraction. In active gas-extraction areas (one or more gas wells within 1 km), average and maximum methane concentrations in drinking-water wells increased with proximity to the nearest gas well and were 19.2 and 64 mg CH_4 L^{-1} ($n = 26$), a potential explosion hazard; in contrast, dissolved methane samples in neighboring nonextraction sites (no gas wells within 1 km) within similar geologic formations and hydrogeologic regimes averaged only 1.1 mg L^{-1} ($P < 0.05$; $n = 34$). Average δ^{13}C-CH_4 values of dissolved methane in shallow groundwater were significantly less negative for active than for nonactive sites (-37 ± 7‰ and -54 ± 11‰, respectively; $P < 0.0001$). These δ^{13}C-CH_4 data, coupled with the ratios of methane-to-higher-chain hydrocarbons, and δ^2H-CH_4 values, are consistent with deeper thermogenic methane sources such as the Marcellus and Utica shales at the active sites and matched gas geochemistry from gas wells nearby. In contrast, lower-concentration samples from shallow groundwater at nonactive sites had isotopic signatures reflecting a more biogenic or mixed biogenic/thermogenic methane source. We found no evidence for contamination of drinking-water samples with deep saline brines or fracturing fluids. We conclude that greater stewardship, data, and—possibly—regulation are needed to ensure the sustainable future of shale-gas extraction and to improve public confidence in its use.

groundwater | organic-rich shale | isotopes | formation waters | water chemistry

Increases in natural-gas extraction are being driven by rising energy demands, mandates for cleaner burning fuels, and the economics of energy use (1–5). Directional drilling and hydraulic-fracturing technologies are allowing expanded natural-gas extraction from organic-rich shales in the United States and elsewhere (2, 3). Accompanying the benefits of such extraction (6, 7) are public concerns about drinking-water contamination from drilling and hydraulic fracturing that are ubiquitous but lack a strong scientific foundation. In this paper, we evaluate the potential impacts associated with gas-well drilling and fracturing on shallow groundwater systems of the Catskill and Lockhaven formations that overlie the Marcellus Shale in Pennsylvania and the Genesee Group that overlies the Utica Shale in New York (Figs. 1 and 2 and Fig. S1). Our results show evidence for methane contamination of shallow drinking-water systems in at least three areas of the region and suggest important environmental risks accompanying shale-gas exploration worldwide.

The drilling of organic-rich shales, typically of Upper Devonian to Ordovician age, in Pennsylvania, New York, and elsewhere in the Appalachian Basin is spreading rapidly, raising concerns for impacts on water resources (8, 9). In Susquehanna County, Pennsylvania alone, approved gas-well permits in the Marcellus formation increased 27-fold from 2007 to 2009 (10).

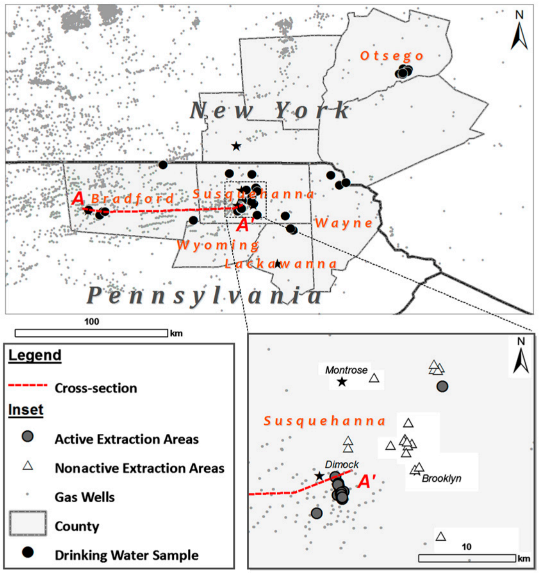

Fig. 1. Map of drilling operations and well-water sampling locations in Pennsylvania and New York. The star represents the location of Binghamton, New York. (*Inset*) A close-up in Susquehanna County, Pennsylvania, showing areas of active (closed circles) or nonactive (open triangles) extraction. A drinking-water well is classified as being in an active extraction area if a gas well is within 1 km (see *Methods*). Note that drilling has already spread to the area around Brooklyn, Pennsylvania, primarily a nonactive location at the time of our sampling (see inset). The stars in the inset represent the towns of Dimock, Brooklyn, and Montrose, Pennsylvania.

Concerns for impacts to groundwater resources are based on (*i*) fluid (water and gas) flow and discharge to shallow aquifers due to the high pressure of the injected fracturing fluids in the gas wells (10); (*ii*) the toxicity and radioactivity of produced water from a mixture of fracturing fluids and deep saline formation waters that may discharge to the environment (11); (*iii*) the potential explosion and asphyxiation hazard of natural gas; and (*iv*) the large number of private wells in rural areas that rely on shallow groundwater for household and agricultural use—up to one million wells in Pennsylvania alone—that are typically unregulated and untested (8, 9, 12). In this study, we analyzed groundwater from 68 private water wells from 36- to 190-m deep in

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Author contributions: S.G.O., A.V., and R.B.J. designed research; S.G.O. and N.R.W. performed research; A.V. contributed new reagents/analytic tools; S.G.O., A.V., N.R.W., and R.B.J. analyzed data; and S.G.O., A.V., N.R.W., and R.B.J. wrote the paper.

The authors declare no conflict of interest.

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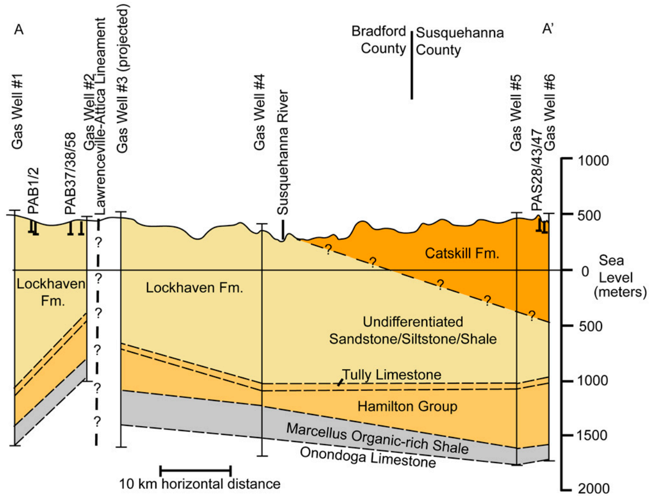

Fig. 2. Geologic cross-section of Bradford and western Susquehanna Counties created from gas-well log data provided by the Pennsylvania Department of Conservation and Natural Resources. The approximate location of the Lawrenceville-Attica Lineament is taken from Alexander et al. (34). The Ordovician Utica organic-rich shale (not depicted in the figure) underlies the Middle Devonian Marcellus at approximately 3,500 m below the ground surface.

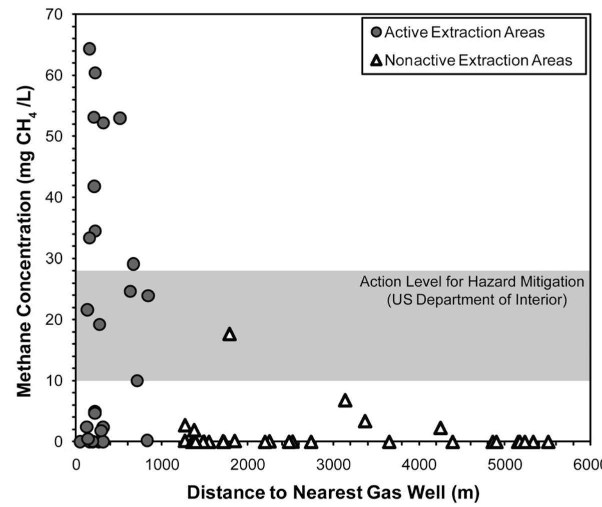

Fig. 3. Methane concentrations (milligrams of CH_4 L^{-1}) as a function of distance to the nearest gas well from active (closed circles) and nonactive (open triangles) drilling areas. Note that the distance estimate is an upper limit and does not take into account the direction or extent of horizontal drilling underground, which would decrease the estimated distances to some extraction activities. The precise locations of natural-gas wells were obtained from the Pennsylvania Department of Environmental Protection and Pennsylvania Spatial Data Access databases (ref. 35; accessed Sept. 24, 2010).

northeast Pennsylvania (Catskill and Lockhaven formations) and upstate New York (Genesee formation) (see Figs. 1 and 2 and *SI Text*), including measurements of dissolved salts, water isotopes (^{18}O and ^{2}H), and isotopes of dissolved constituents (carbon, boron, and radium). Of the 68 wells, 60 were also analyzed for dissolved-gas concentrations of methane and higher-chain hydrocarbons and for carbon and hydrogen isotope ratios of methane. Although dissolved methane in drinking water is not currently classified as a health hazard for ingestion, it is an asphyxiant in enclosed spaces and an explosion and fire hazard (8). This study seeks to evaluate the potential impact of gas drilling and hydraulic fracturing on shallow groundwater quality by comparing areas that are currently exploited for gas (defined as active—one or more gas wells within 1 km) to those that are not currently associated with gas drilling (nonactive; no gas wells within 1 km), many of which are slated for drilling in the near future.

Results and Discussion

Methane concentrations were detected generally in 51 of 60 drinking-water wells (85%) across the region, regardless of gas industry operations, but concentrations were substantially higher closer to natural-gas wells (Fig. 3). Methane concentrations were 17-times higher on average (19.2 mg CH_4 L^{-1}) in shallow wells from active drilling and extraction areas than in wells from nonactive areas (1.1 mg L^{-1} on average; $P < 0.05$; Fig. 3 and Table 1). The *average* methane concentration in shallow groundwater in active drilling areas fell within the defined action level (10–28 mg L^{-1}) for hazard mitigation recommended by the US Office of the Interior (13), and our maximum observed value of 64 mg L^{-1} is well above this hazard level (Fig. 3). Understanding the origin of this methane, whether it is shallower biogenic or deeper thermogenic gas, is therefore important for identifying the source of contamination in shallow groundwater systems.

The $\delta^{13}C$-CH_4 and $\delta^{2}H$-CH_4 values and the ratio of methane to higher-chain hydrocarbons (ethane, propane, and butane) can typically be used to differentiate shallower, biologically derived methane from deeper physically derived thermogenic methane (14). Values of $\delta^{13}C$-CH_4 less negative than approximately −50‰ are indicative of deeper thermogenic methane, whereas values more negative than −64‰ are strongly indicative of microbial methane (14). Likewise, $\delta^{2}H$-CH_4 values more negative than about −175‰, particularly when combined with low $\delta^{13}C$-CH_4 values, often represent a purer biogenic methane origin (14).

The average $\delta^{13}C$-CH_4 value in shallow groundwater in active drilling areas was -37 ± 7‰, consistent with a deeper thermogenic methane source. In contrast, groundwater from nonactive areas in the same aquifers had much lower methane concentrations and significantly lower $\delta^{13}C$-CH_4 values (average of $-54\pm$ 11‰; $P < 0.0001$; Fig. 4 and Table 1). Both our $\delta^{13}C$-CH_4 data and $\delta^{2}H$-CH_4 data (see Fig. S2) are consistent with a deeper thermogenic methane source at the active sites and a more biogenic or mixed methane source for the lower-concentration samples from nonactive sites (based on the definition of Schoell, ref. 14).

Because ethane and propane are generally not coproduced during microbial methanogenesis, the presence of higher-chain hydrocarbons at relatively low methane-to-ethane ratios (less than approximately 100) is often used as another indicator of deeper thermogenic gas (14, 15). Ethane and other higher-chain hydrocarbons were detected in only 3 of 34 drinking-water wells from nonactive drilling sites. In contrast, ethane was detected in 21 of 26 drinking-water wells in active drilling sites. Additionally, propane and butane were detected (>0.001 mol %) in eight and two well samples, respectively, from active drilling areas but in no wells from nonactive areas.

Further evidence for the difference between methane from water wells near active drilling sites and neighboring nonactive sites is the relationship of methane concentration to $\delta^{13}C$-CH_4 values (Fig. 4*A*) and the ratios of methane to higher-chain hydro-

Table 1. Mean values ± standard deviation **of methane concentrations (as milligrams of CH_4 L^{-1}) and carbon isotope composition in methane in shallow groundwater $\delta^{13}C$-CH_4 sorted by aquifers and proximity to gas wells (active vs. nonactive)**

Water source, *n*	milligrams CH_4 L^{-1}	$\delta^{13}C$-CH_4, ‰
Nonactive Catskill, 5	1.9 ± 6.3	−52.5 ± 7.5
Active Catskill, 13	26.8 ± 30.3	−33.5 ± 3.5
Nonactive Genesee, 8	1.5 ± 3.0	−57.5 ± 9.5
Active Genesee, 1	0.3	−34.1
Active Lockhaven, 7	50.4 ± 36.1	−40.7 ± 6.7
Total active wells, 21	19.2	−37 ± 7
Total nonactive wells, 13	1.1	−54 ± 11

The variable *n* refers to the number of samples.

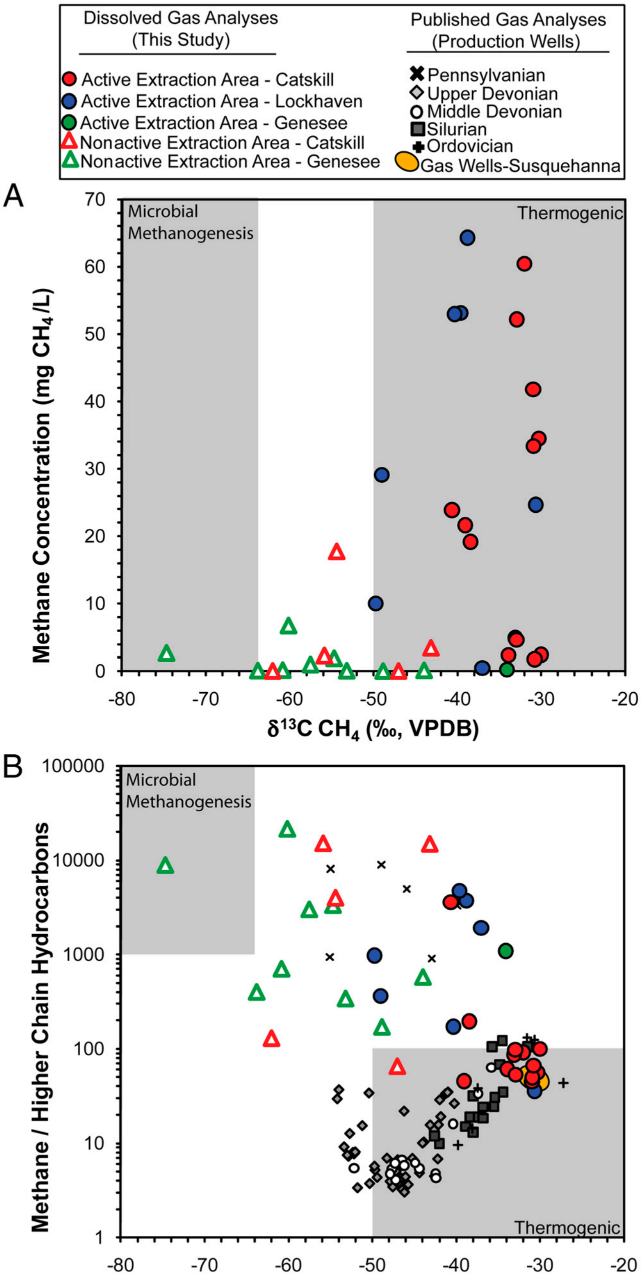

Fig. 4. (*A*) Methane concentrations in groundwater versus the carbon isotope values of methane. The nonactive and active data depicted in Fig. 3 are subdivided based on the host aquifer to illustrate that the methane concentrations and δ^{13}C values increase with proximity to natural-gas well drilling regardless of aquifer formation. Gray areas represent the typical range of thermogenic and biogenic methane taken from Osborn and Mcintosh (18). VPDB, Vienna Pee Dee belemnite. (*B*) Bernard plot (15) of the ratio of methane to higher-chain hydrocarbons versus the δ^{13}C of methane. The smaller symbols in grayscale are from published gas-well samples from gas production across the region (16–18). These data generally plot along a trajectory related to reservoir age and thermal maturity (Upper Devonian through Ordovician; see text for additional details). The gas-well data in the orange ovals are from gas wells in our study area in Susquehanna County, Pennsylvania (data from Pennsylvania Department of Environmental Protection). Gray areas represent typical ranges of thermogenic and biogenic methane (data from Osborn and McIntosh, ref. 18).

carbons versus δ^{13}C-CH_4 (Fig. 4*B*). Methane concentrations not only increased in proximity to gas wells (Fig. 3), the accompanying δ^{13}C-CH_4 values also reflected an increasingly thermogenic methane source (Fig. 4*A*).

Using a Bernard plot (15) for analysis (Fig. 4*B*), the enriched δ^{13}C-CH_4 (approximately > -50‰) values accompanied by low ratios of methane to higher-chain hydrocarbons (less than approximately 100) in drinking-water wells also suggest that dissolved gas is more thermogenic at active than at nonactive sites (Fig. 4*B*). For instance, 12 dissolved-gas samples at active drilling sites fell along a regional gas trajectory that increases with reservoir age and thermal maturity of organic matter, with samples from Susquehanna County, Pennsylvania specifically matching natural-gas geochemistry from local gas wells (Fig. 4*B*, orange oval). These 12 samples and local natural-gas samples are consistent with gas sourced from thermally mature organic matter of Middle Devonian and older depositional ages often found in Marcellus Shale from approximately 2,000 m below the surface in the northern Appalachian Basin (14–19) (Fig. 4*B*). In contrast, none of the methane samples from nonactive drilling areas fell upon this trajectory (Fig. 4*B*); eight dissolved-gas samples in Fig. 4*B* from active drilling areas and all of the values from nonactive areas may instead be interpreted as mixed biogenic/thermogenic gas (18) or, as Laughrey and Baldassare (17) proposed for their Pennsylvanian gas data (Fig. 4*B*), the early migration of wet thermogenic gases with low-δ^{13}C-CH_4 values and high methane-to-higher-chain hydrocarbon ratios. One data point from a nonactive area in New York fell squarely in the parameters of a strictly biogenic source as defined by Schoell (14) (Fig. 4*B*, upper-left corner).

Carbon isotopes of dissolved inorganic carbon (δ^{13}C-DIC $>$ $+10$‰) and the positive correlation of δ^2H of water and δ^2H of methane have been used as strong indicators of microbial methane, further constraining the source of methane in shallow groundwater (depth less than 550 m) (18, 20). Our δ^{13}C-DIC values were fairly negative and show no association with the δ^{13}C-CH_4 values (Fig. S3), which is not what would be expected if methanogenesis were occurring locally in the shallow aquifers. Instead, the δ^{13}C-DIC values from the shallow aquifers plot within a narrow range typical for shallow recharge waters, with the dissolution of CO_2 produced by respiration as water passes downward through the soil critical zone. Importantly, these values do not indicate extensive microbial methanogenesis or sulfate reduction. The data do suggest gas-phase transport of methane upward to the shallow groundwater zones sampled for this study ($<$190 m) and dissolution into shallow recharge waters locally. Additionally, there was no positive correlation between the δ^2H values of methane and δ^2H of water (Fig. S4), indicating that microbial methane derived in this shallow zone is negligible. Overall, the combined gas and formation-water results indicate that thermogenic gas from thermally mature organic matter of Middle Devonian and older depositional ages is the most likely source of the high methane concentrations observed in the shallow water wells from active extraction sites.

A different potential source of shallow groundwater contamination associated with gas drilling and hydraulic fracturing is the introduction of hypersaline formation brines and/or fracturing fluids. The average depth range of drinking-water wells in northeastern Pennsylvania is from 60 to 90 m (12), making the average vertical separation between drinking-water wells and the Marcellus Shale in our study area between approximately 900 and 1,800 m (Fig. 2). The research area, however, is located in tectonically active areas with mapped faults, earthquakes, and lineament features (Fig. 2 and Fig. S1). The Marcellus formation also contains two major sets of joints (21) that could be conduits for directed pressurized fluid flow. Typical fracturing activities in the Marcellus involve the injection of approximately 13–19 million liters of water per well (22) at pressures of up to 69,000 kPa. The majority of this fracturing water typically stays underground and could in principle displace deep formation water upward into shallow aquifers. Such deep formation waters often have high concentrations of total dissolved solids >250,000 mg L^{-1}, trace toxic elements, (18), and naturally occurring radioactive materials, with activities as high as 16,000 picocuries per liter ($1\ pCi\ L^{-1} = 0.037$ becquerels per liter) for ^{226}Ra compared to a drinking-water standard of $5\ pCi\ L^{-1}$ for combined ^{226}Ra and ^{226}Ra (23).

We evaluated the hydrochemistry of our 68 drinking-water wells and compared these data to historical data of 124 wells in the Catskill and Lockhaven aquifers (24, 25). We used three types of indicators for potential mixing with brines and/or saline fracturing fluids: (*i*) major inorganic chemicals; (*ii*) stable isotope signatures of water ($\delta^{18}O$, $\delta^{2}H$); and (*iii*) isotopes of dissolved constituents ($\delta^{13}C$-DIC, $\delta^{11}B$, and ^{226}Ra). Based on our data (Table 2), we found no evidence for contamination of the shallow wells near active drilling sites from deep brines and/or fracturing fluids. All of the Na^{+}, Cl^{-}, Ca^{2+}, and DIC concentrations in wells from active drilling areas were consistent with the baseline historical data, and none of the shallow wells from active drilling areas had either chloride concentrations $>60\ mg\ L^{-1}$ or Na-Ca-Cl compositions that mirrored deeper formation waters (Table 2). Furthermore, the mean isotopic values of $\delta^{18}O$, $\delta^{2}H$, $\delta^{13}C$-DIC, $\delta^{11}B$, and ^{226}Ra in active and nonactive areas were indistinguishable. The ^{226}Ra values were consistent with available historical data (25), and the composition of $\delta^{18}O$ and $\delta^{2}H$ in the well-water appeared to be of modern meteoric origin for Pennsylvania (26) (Table 2 and Fig. S5). In sum, the geochemical and isotopic features for water we measured in the shallow wells from both active and nonactive areas are consistent with historical data and inconsistent with contamination from mixing Marcellus Shale formation water or saline fracturing fluids (Table 2).

There are at least three possible mechanisms for fluid migration into the shallow drinking-water aquifers that could help explain the increased methane concentrations we observed near gas wells (Fig. 3). The first is physical displacement of gas-rich deep solutions from the target formation. Given the lithostatic and hydrostatic pressures for 1–2 km of overlying geological strata, and our results that appear to rule out the rapid movement of deep brines to near the surface, we believe that this mechanism is unlikely. A second mechanism is leaky gas-well casings (e.g., refs. 27 and 28). Such leaks could occur at hundreds of meters underground, with methane passing laterally and vertically through fracture systems. The third mechanism is that the process of hydraulic fracturing generates new fractures or enlarges existing ones above the target shale formation, increasing the connectivity of the fracture system. The reduced pressure following the fracturing activities could release methane in solution, leading to methane exsolving rapidly from solution (29), allowing methane gas to potentially migrate upward through the fracture system.

Methane migration through the 1- to 2-km-thick geological formations that overlie the Marcellus and Utica shales is less likely as a mechanism for methane contamination than leaky well casings, but might be possible due to both the extensive fracture systems reported for these formations and the many older, uncased wells drilled and abandoned over the last century and a half in Pennsylvania and New York. The hydraulic conductivity in the overlying Catskill and Lockhaven aquifers is controlled by a secondary fracture system (30), with several major faults and lineaments in the research area (Fig. 2 and Fig. S1). Consequently, the high methane concentrations with distinct positive $\delta^{13}C$-CH_4 and $\delta^{2}H$-CH_4 values in the shallow groundwater from active areas could in principle reflect the transport of a deep methane source associated with gas drilling and hydraulic-fracturing activities. In contrast, the low-level methane migration to the surface groundwater aquifers, as observed in the nonactive areas, is likely a natural phenomenon (e.g., ref. 31). Previous studies have shown that naturally occurring methane in shallow aquifers is typically associated with a relatively strong biogenic signature indicated by depleted $\delta^{13}C$-CH_4 and $\delta^{2}H$-CH_4 compositions (32) coupled with high ratios of methane to higher-chain hydrocarbons (33), as we observed in Fig. 4*B*. Several models have been developed to explain the relatively common phenomenon of rapid vertical transport of gases (Rn, CH_4, and CO_2) from depth to the surface (e.g., ref. 31), including pressure-driven continuous gas-phase flow through dry or water-saturated fractures and density-driven buoyancy of gas microbubbles in aquifers and water-filled fractures (31). More research is needed across this and other regions to determine the mechanism(s) controlling the higher methane concentrations we observed.

Based on our groundwater results and the litigious nature of shale-gas extraction, we believe that long-term, coordinated sampling and monitoring of industry and private homeowners is needed. Compared to other forms of fossil-fuel extraction, hydraulic fracturing is relatively poorly regulated at the federal level. Fracturing wastes are not regulated as a hazardous waste under the Resource Conservation and Recovery Act, fracturing wells are not covered under the Safe Drinking Water Act, and only recently has the Environmental Protection Agency asked fracturing

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Table 2. Comparisons of selected major ions and isotopic results in drinking-water wells from this study to data available on the same formations (Catskill and Lockhaven) in previous studies (24, 25) and to underlying brines throughout the Appalachian Basin (18)

	Active		Nonactive		Previous studies (background)		
	Lockhaven formation $N = 8$	Catskill formation $N = 25$	Catskill formation $N = 22$	Genesee group $N = 12$	Lockhaven formation (25) $N = 45$	Catskill formation (24) $N = 79$	Appalachian brines (18, 23) $N = 21$
Alkalinity as HCO_3^-,							
mg L^{-1}	285 ± 36	157 ± 56	127 ± 53	158 ± 56	209 ± 77	133 ± 61	150 ± 171
mM	[4.7 ± 0.6]	[2.6 ± 0.9]	[2.1 ± 0.9]	[2.6 ± 0.9]	[3.4 ± 1.3]	[2.2 ± 1.0]	[2.5 ± 2.8]
Sodium, mg L^{-1}	87 ± 22	23 ± 30	17 ± 25	29 ± 23	100 ± 312	21 ± 37	33,000 ± 11,000
Chloride, mg L^{-1}	25 ± 17	11 ± 12	17 ± 40	9 ± 19	132 ± 550	13 ± 42	92,000 ± 32,000
Calcium, mg L^{-1}	22 ± 12	31 ± 13	27 ± 9	26 ± 5	49 ± 39	29 ± 11	16,000 ± 7,000
Boron, μg L^{-1}	412 ± 156	93 ± 167	42 ± 93	200 ± 130	NA	NA	3,700 ± 3,500
$\delta^{11}B$ ‰	27 ± 4	22 ± 6	23 ± 6	26 ± 6	NA	NA	39 ± 6
^{226}Ra, pCi L^{-1}	0.24 ± 0.2	0.16 ± 0.15	0.17 ± 0.14	0.2 ± 0.15	0.56 ± 0.74	NA	6,600 ± 5,600
$\delta^{2}H$, ‰, VSMOW	−66 ± 5	−64 ± 3	−68 ± 6	−76 ± 5	NA	NA	−41 ± 6
$\delta^{18}O$, ‰, VSMOW	−10 ± 1	−10 ± 0.5	−11 ± 1	−12 ± 1	NA	NA	−5 ± 1

Some data for the active Genesee Group and nonactive Lockhaven Formation are not included because of insufficient sample sizes (NA). Values represent means ±1 standard deviation. NA, not available.

N values for $\delta^{11}B$ ‰ analysis are 8, 10, 3, 6, and 5 for active Lockhaven, active Catskill, nonactive Genesee, nonactive Catskill, and brine, respectively. *N* values for ^{226}Ra are 6, 7, 3, 10, 5, and 13 for active Lockhaven, active Catskill, nonactive Genesee, nonactive Catskill, background Lockhaven, and brine, respectively. $\delta^{11}B$ ‰ normalized to National Institute of Standards and Technology Standard Reference Material 951. $\delta^{2}H$ and $\delta^{18}O$ normalized to Vienna Standard Mean Ocean Water (VSMOW).

firms to voluntarily report a list of the constituents in the fracturing fluids based on the Emergency Planning and Community Right-to-Know Act. More research is also needed on the mechanism of methane contamination, the potential health consequences of methane, and establishment of baseline methane data in other locations. We believe that systematic and independent data on groundwater quality, including dissolved-gas concentrations and isotopic compositions, should be collected before drilling operations begin in a region, as is already done in some states. Ideally, these data should be made available for public analysis, recognizing the privacy concerns that accompany this issue. Such baseline data would improve environmental safety, scientific knowledge, and public confidence. Similarly, long-term monitoring of groundwater and surface methane emissions during and after extraction would clarify the extent of problems and help identify the mechanisms behind them. Greater stewardship, knowledge, and—possibly—regulation are needed to ensure the sustainable future of shale-gas extraction.

Methods

A total of 68 drinking-water samples were collected in Pennsylvania and New York from bedrock aquifers (Lockhaven, 8; Catskill, 47; and Genesee, 13) that overlie the Marcellus or Utica shale formations (Fig. S1). Wells were purged to remove stagnant water, then monitored for pH, electrical conductance, and temperature until stable values were recorded. Samples were collected "upstream" of any treatment systems, as close to the water well as possible, and preserved in accordance with procedures detailed in *SI Methods*. Dissolved-gas samples were analyzed at Isotech Laboratories and water chemical and isotope (O, H, B, C, Ra) compositions were measured at Duke University (see *SI Methods* for analytical details).

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Washington, DC 20460

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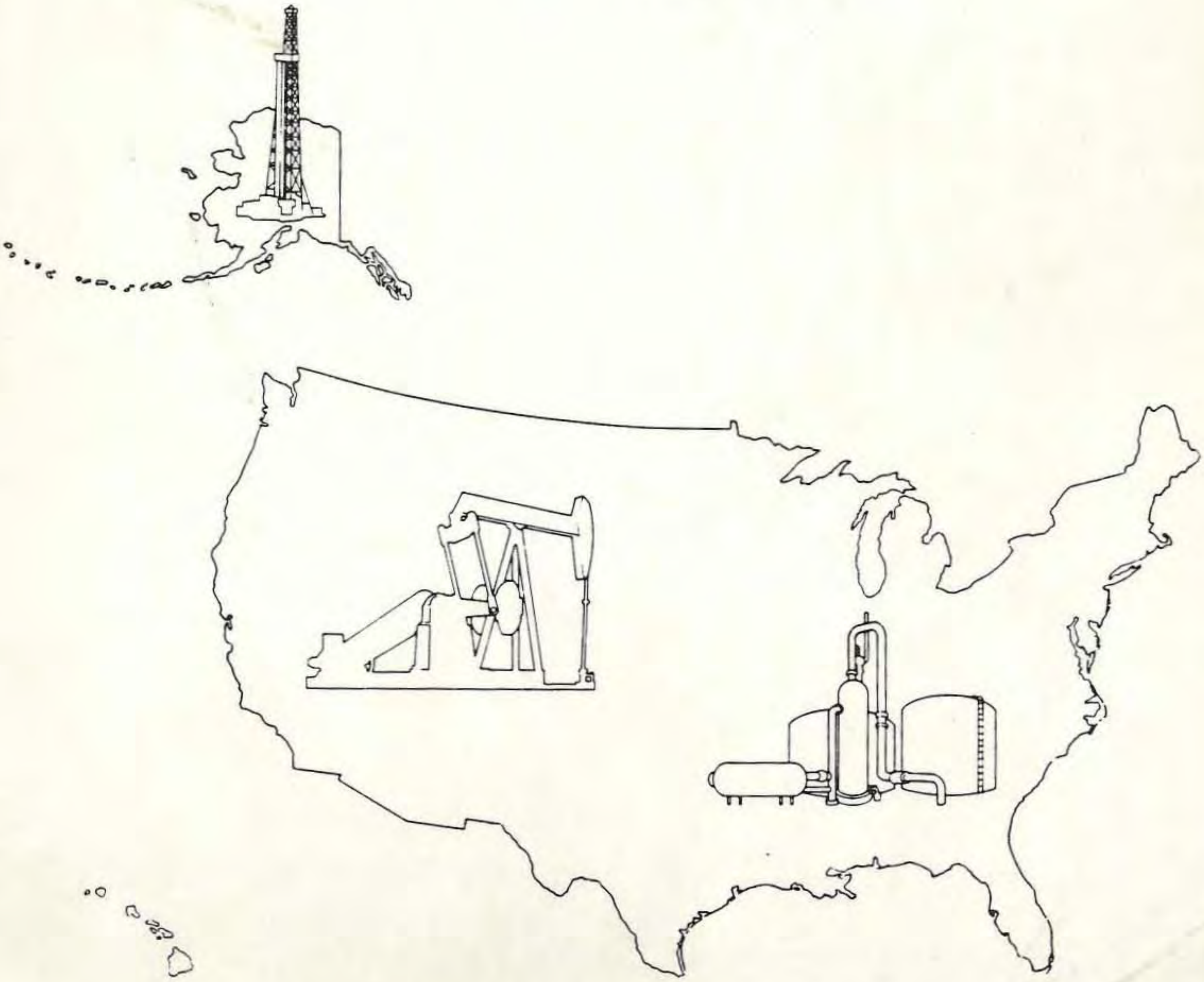
Solid Waste

EPA

Report to Congress

Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy

Volume 1 of 3
Oil and Gas



Report to Congress

Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy

VOLUME 1 OF 3

OIL AND GAS

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

Office of Solid Waste and Emergency Response
Washington, D.C. 20460

December 1987

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CHAPTER I

INTRODUCTION

STATUTORY REQUIREMENTS AND GENERAL PURPOSE

Under Section 3001(b)(2)(A) of the 1980 Amendments to the Resource Conservation and Recovery Act (RCRA), Congress temporarily exempted several types of solid wastes from regulation as hazardous wastes, pending further study by the Environmental Protection Agency (EPA).[1] Among the categories of wastes exempted were "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy." Section 8002(m) of the Amendments requires the Administrator to study these wastes and submit a final report to Congress. This report responds to those requirements. Because of the many inherent differences between the oil and gas industry and the geothermal energy industry, the report is submitted in three volumes. Volume 1 (this volume) covers the oil and gas industry; Volume 2 covers the geothermal energy industry; Volume 3 covers State regulatory summaries for the oil and gas industry and includes a glossary of terms. This report discusses wastes generated only by the onshore segment of the oil and gas industry.

The original deadline for this study was October 1982. EPA failed to meet that deadline, and in August 1985 the Alaska Center for the Environment sued the Agency for its failure to conduct the study.

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[1] EPA is also required to make regulatory determinations affecting the oil and gas and geothermal energy industries under several other major statutes. These include designing appropriate effluent limitations guidelines under the Clean Water Act, determining emissions standards under the Clean Air Act, and implementing the requirements of the underground injection control program under the Safe Drinking Water Act.

EPA entered into a consent order, obligating it to submit the final Report to Congress on or before August 31, 1987. In April 1987, this schedule was modified and the deadline for submittal of the final Report to Congress was extended to December 31, 1987.

Following submission of the current study, and after public hearings and opportunity for comment, the Administrator of EPA must determine either to promulgate regulations under the hazardous waste management provisions of RCRA (Subtitle C) or to declare that such regulations are unwarranted. Any regulations would not take effect unless authorized by an act of Congress.

This does not mean that the recommendations of this report are limited to a narrow choice between application of full Subtitle C regulation and continuation of the current exemption. Section 8002(m) specifically requires the Administrator to propose recommendations for "[both] Federal and non-Federal actions" to prevent or substantially mitigate any adverse effects associated with management of wastes from these industries. EPA interprets this statement as a directive to consider the practical and prudent means available to avert health or environmental damage associated with the improper management of oil, gas, or geothermal wastes. The Agency has identified a wide range of possible actions, including voluntary programs, cooperative work with States to modify their programs, and Federal action outside of RCRA Subtitle C, such as RCRA Subtitle D, the existing Underground Injection Control Program under the Safe Drinking Water Act, or the National Pollution Discharge Elimination System under the Clean Water Act.

In this light, EPA emphasizes that the recommendations presented here do <u>not</u> constitute a regulatory determination. Such a determination cannot be made until the public has had an opportunity to review and comment on this report (i.e., the determination cannot be made until June 1988). Furthermore, the Agency is, in several important areas, presenting optional approaches involving further research and consultation with the States and other affected parties.

STUDY APPROACH

The study factors are listed in the various paragraphs of Section 8002(m), which is quoted in its entirety as Exhibit 1 (page I-13). For clarity, the Agency has designed this report to respond specifically to each study factor within separate chapters or sections of chapters. It is important to note that although every study factor has been weighed in arriving at the conclusions and recommendations of this report, no single study factor has a determining influence on the conclusions and recommendations.

The study factors are defined in the paragraphs below, which also introduce the methodologies used to analyze each study area with respect to the oil and gas industry. More detailed methodological discussions can be found later in this report and in the supporting documentation and appendices.

STUDY FACTORS

The principal study factors of concern to Congress are listed in subparagraphs (A) through (G) of Section 8002(m)(1) (see Exhibit 1). The introductory and concluding paragraphs of the Section, however, also contain directives to the Agency on the content of this study. This work has therefore been organized to respond to the following comprehensive interpretation of the 8002(m) study factors.

Study Factor 1 - Defining Exempt Wastes

RCRA describes the exempt wastes in broad terms, referring to "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy." The Agency, therefore, relied to the extent possible on the legislative history of the amendments, which provides guidance on the definition of other wastes. The tentative scope of the exemption is discussed in Chapter II of this volume.

Study Factor 2 - Specifying the Sources and Volumes of Exempt Wastes

In response to Section 8002(m)(1)(A), EPA has developed estimates of the sources and volumes of all exempt wastes. The estimates are presented in Chapter II, "Overview of the Industry."

Comprehensive information on the volumes of exempt wastes from oil and gas operations is not routinely collected nationwide; however, estimates of total volumes produced can be made through a variety of approaches.

With respect to drilling muds and related wastes, two methods for estimating volumes are presented. The first, developed early in the study by EPA, estimates drilling wastes as a function of the size of reserve pits. The second method is based on a survey conducted by the American Petroleum Institute (API) on production of drilling muds and completion fluids, cuttings, and other associated wastes discharged to reserve pits. Both methods and their results are included in Chapter II.

Similarly, EPA and API developed independent estimates of produced water volumes. EPA's first estimates were based on a survey of the injection, production, and hauling reports of State agencies; API's were based on its own survey of production operations. Again, this report presents the results of both methodologies.

Study Factor 3 - Characterizing Wastes

Section 8002(m) does not directly call for a laboratory analysis of the exempted wastes, but the Agency considers such a review to be a necessary and appropriate element of this study. Analysis of the principal high-volume wastes (i.e., drilling fluids and produced waters) can help to indicate whether any of the wastes may be hazardous under the definitions of RCRA Subtitle C. Wastes were examined with regard to whether they exhibited any of the hazardous characteristics defined under 40 CFR 261 of RCRA, including extraction procedure toxicity, ignitability, corrosivity, and reactivity. Also, a compositional analysis was performed for the purpose of determining if hazardous constituents were present in the wastes at concentrations exceeding accepted health-based limits.

EPA therefore conducted a national screening type program that sampled facilities to compile relevant data on waste characteristics. Sites were selected at random in cooperation with State regulatory agencies, based on a division of the United States into zones (see Figure I-1). Samples were subjected to extensive analysis, and the results were subjected to rigorous quality control procedures prior to their publication in January 1987. Simultaneously, using a different sampling methodology, API sampled the same sites and wastes covered by the EPA-sponsored survey. Chapter II of this report, "Overview of the Industry," presents a summary of results of both programs.

Study Factor 4 - Describing Current Disposal Practices

Section 8002(m)(1)(B) calls for an analysis of current disposal practices for exempted wastes. Chapter III, "Current and Alternative Waste Management Practices," summarizes EPA's review, which was based on a number of sources. Besides reviewing the technical literature, EPA sent representatives to regulatory agencies of the major oil- and gas-producing States to discuss current waste management technologies with State representatives. In addition, early drafts of this study's characterizations of such technologies were reviewed by State and industry representatives.

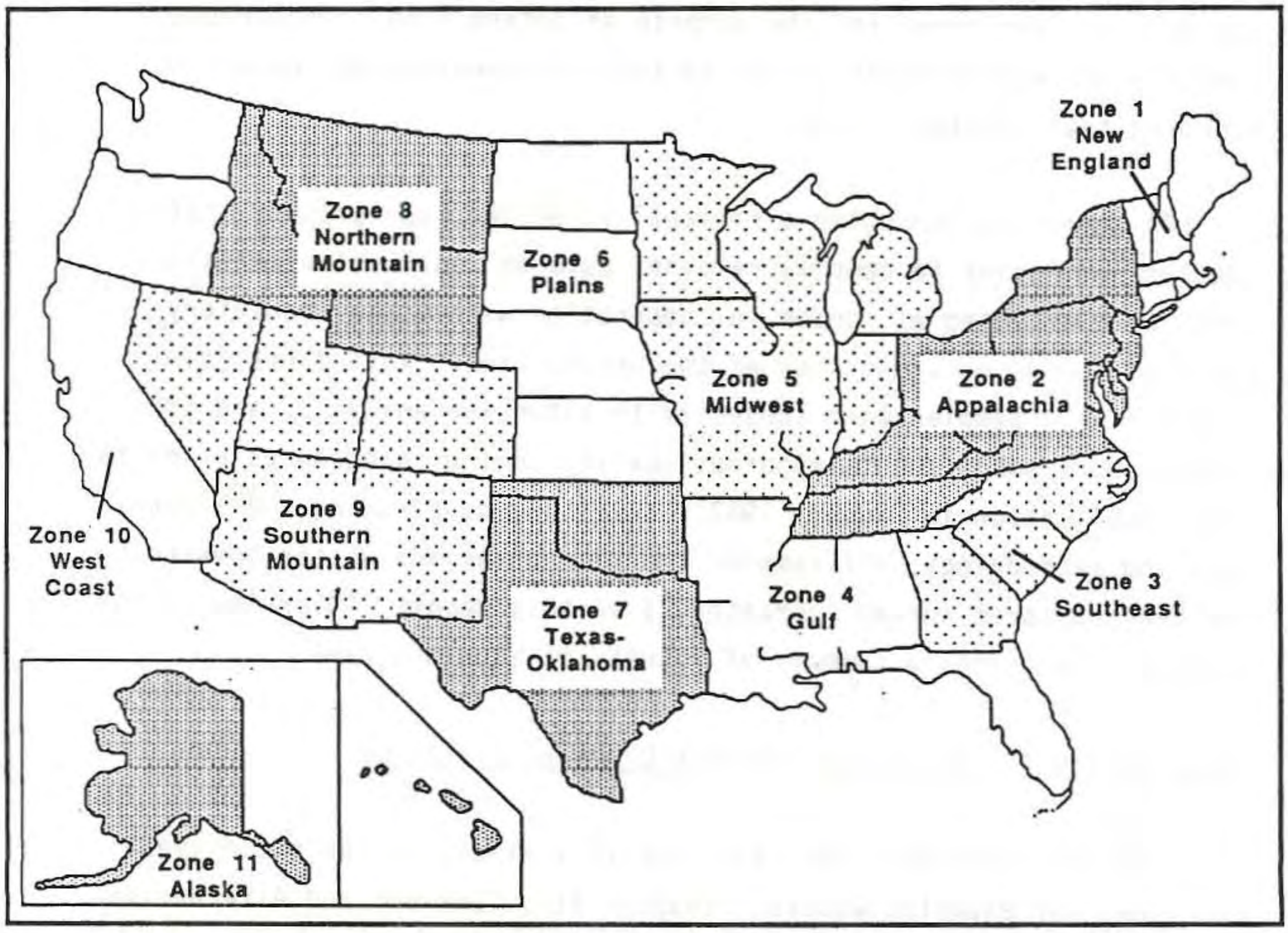

Figure I-1
Oil and Gas Production Zones
Divisions of the United States Used for the RCRA Section 8002(m) Study of Oil and Gas Wastes

The Agency intentionally has not compiled an exhaustive review of waste management technologies used by the oil and gas industry. As stressed throughout this volume, conditions and methods vary widely from State to State and operation to operation. Rather, the Agency has described the principal and common methods of managing field-generated wastes and has discussed these practices in general and qualitative terms in relation to their effectiveness in protecting human health and the environment.

Study Factor 5 - Documenting Evidence of Damage to Human Health and the Environment Caused by Management of Oil and Gas Wastes

Section 8002(m)(1)(D) requires EPA to analyze "documented cases" of health and environmental damage related to surface runoff or leachate. Although EPA has followed this instruction, paragraph (1) of the section also refers to "adverse effects of such wastes [i.e., exempted wastes, not necessarily only runoff and leachate] on humans, water, air, health, welfare, and natural resources...."

Chapter IV, "Damage Cases," summarizes EPA's effort to collect documented evidence of harm to human health, the environment, or valuable resources. Cases were accepted for presentation in this report only if, prior to commencement of field work, they met the standards of the test of proof, defined as (1) a scientific study, (2) an administrative finding of damage under State or other applicable authority, or (3) determination of damage by a court. Many cases met more than one such test of proof.

A number of issues of interpretation have been raised that must be clarified at the outset. First, in the Agency's opinion, the case study approach, such as that called for by Section 8002(m), is intended only to define the nature and range of known damages, not to estimate the frequency or extent of damages associated with typical operations. The results presented here should not be interpreted as having statistical significance. The number of cases reported in each category bears no statistically significant relationship to the actual types and distribution of damages that may or may not exist across the United States.

Second, the total number of cases bears no implied or intended relationship to the total extent of damage from oil or gas operations caused at present or in the past.

Third, Section 8002(m)(1)(D) makes no mention of defining relationships between documented damages and violations of State or other Federal regulations. As a practical necessity, EPA has in fact relied heavily on State enforcement and complaint files in gathering documentation for this section of the report.[2] Consequently, a large proportion of cases reported here involve violations of State regulations. However, the fact that the majority of cases presented here involve State enforcement actions implies nothing, positive or negative, about the success of State programs in enforcing their requirements on industry.

Study Factor 6 - Assessing Potential Danger to Human Health or the Environment from the Wastes

Section 8002(m)(1)(C) requires analysis of the potential dangers of surface runoff and leachate. These potential effects can involve all types of damages over a long period of time and are not necessarily limited to the categories of damages for which documentation is currently available.

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[2] Other sources have included evidence submitted by private citizens or supplied by attorneys in response to inquiries from EPA researchers.

Several methods of estimating potential damages are available, and EPA has combined two approaches in responding to this study factor in Chapter V, "Risk Modeling." The first has been to use quantitative risk assessment modeling techniques developed for use elsewhere in the RCRA program. The second has been to apply more qualitative methods, based on traditional environmental assessment techniques.

The goal of both the quantitative and the qualitative risk assessments has been to define the most important factors in causing or averting human health risk and environmental risk from field operations. For the quantitative evaluation, EPA has adapted the EPA Liner Location Model, which was built to evaluate the impacts of land disposal of hazardous wastes, for use in analyzing drilling and production conditions. Since oil and gas operations are in many ways significantly different from land disposal of hazardous wastes, all revisions to the Liner Location Model and assumptions made in its present application have been extensively documented and are summarized in Chapter V. The procedures of traditional environmental assessment needed no modification to be applied.

As is true in the damage case work, the results of the modeling analysis have no statistical significance in terms of either the pattern or the extent of damages projected. The Agency modeled a subset of prototype situations, designed to roughly represent significant variations in conditions across the country. The results are very useful for characterizing the interactions of technological, geological, and climatic differences as they influence the potential for damages.

Study Factor 7 - Reviewing the Adequacy of Government and Private Measures to Prevent and/or Mitigate any Adverse Effects

Section 8002 (m)(1) requires that the report's conclusions of any adverse effects associated with current management of exempted wastes include consideration of the "adequacy of means and measures currently employed by the oil and gas industry, Government agencies, and others" to dispose of or recycle wastes or to prevent or mitigate those adverse effects.

Neither the damage case assessment nor the risk assessment provided statistically representative data on the extent of damages, making it impossible to compare damages in any quantitative way to the presence and effectiveness of control efforts. The Agency's response to this requirement is therefore based on a qualitative assessment of all the materials gathered during the course of assembling the report and on a review of State regulatory programs presented in Chapter VII, "Current Regulatory Programs." Chapter VII reviews the elements of programs and highlights possible inconsistencies, lack of specificity, potential problems in implementation, or gaps in coverage. Interpretation of the adequacy of these control efforts is presented in Chapter VIII, "Conclusions."

Study Factor 8 - Defining Alternatives to Current Waste Management Practices

Section 8002 (m)(1) requires EPA to analyze alternatives to current disposal methods. EPA's discussion in response to this study factor is incorporated in Chapter III, "Current and Alternative Waste Management Practices."

Chapter III merges the concepts of current and alternative waste management practices. It does not single out particular technologies as potential substitutes for current practices because of the wide variation in practices among States and among different types of operations. Furthermore, waste management technology in this field is fairly simple. At least for the major high-volume waste streams, no significant, field-proven, newly invented technologies that can be considered "innovative" or "emerging" are in the research or development stage.

Practices that are routine in one location may be considered innovative or alternative elsewhere. On the other hand, virtually every waste management practice that exists can be considered "current" in one specific situation or another.

This does not mean that improvements are not possible: in some cases, currently available technologies may not be properly selected, implemented, or maintained. Near-term improvements in waste management in these industries will likely be based largely on more effective use of what is already available.

Study Factor 9 - Estimating the Costs of Alternative Practices

Subparagraph (F) calls for analysis of costs of alternative practices. The first several sections of Chapter VI, "Costs and Economic Impacts of Alternative Waste Management Practices," present the Agency's analysis of this study factor.

For the purposes of this report, EPA based its cost estimates on 21 prototypical regional projects, defined so as to capture significant differences between major and independent companies and between stripper operations and other projects. The study evaluates costs of waste disposal only for the two principal high-volume waste streams of concern, drilling fluids and produced waters, employing as its baseline the use of unlined reserve pits located at the drill site and the disposal of produced waters in injection wells permitted under the Federal Underground Injection Control Program and located off site.

The study then developed two alternative scenarios that varied the incremental costs of waste management control technology, applied them to each prototype project, and modeled the cost impacts of each. The first scenario imposes a set of requirements typical of full Subtitle C management rules; the second represents a less stringent and extensive range of requirements based, in essence, on uniform nationwide use of the most up-to-date and effective controls now being applied by any of the States. Model results indicate cumulative annual costs, at the project level, of each of the more stringent control scenarios.

Study Factor 10 - Estimating the Economic Impacts on Industry of Alternative Practices

In response to the requirements of subparagraph (G), the final two sections of Chapter VI present the Agency's analysis of the potential economic impacts of nationwide imposition of the two control scenarios analyzed at the project level.

Both the cost and the economic impact predicted in this report are admittedly large. Many significant variations influence the economics of this industry and make it difficult to generalize about impacts on either the project or the national level. In particular, the price of oil itself greatly affects both levels. Fluctuations in the price of oil over the period during which this study was prepared have had a profound influence on project economics, making it difficult to draw conclusions about the current or future impacts of modified waste management practices.

Nevertheless, the Agency believes that the analysis presented here is a reasonable response to Congress's directives, and that the results, while they cannot be exact, accurately reflect the general impacts that might be expected if environmental control requirements were made more stringent.

EXHIBIT 1:
Section 8002(m) Resource Conservation and Recovery Act as amended by PL 96-482

"(m) Drilling Fluids, Produced Waters, and Other Wastes Associated with the Extraction, Development, or Production of Crude Oil or Natural Gas or Geothermal Energy.- (1) The Administrator shall conduct a detailed and comprehensive study and submit a report on the adverse effects, if any, of drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy on human health and the environment, including, but not limited to the effects of such wastes on humans, water, air, health, welfare, and natural resources and on the adequacy of means and measures currently employed by the oil and gas and geothermal drilling and production industry, Government agencies, and others to dispose of and utilize such wastes and to prevent or substantially mitigate such adverse effects. Such study shall include an analysis of-

"(A) the sources and volume of discarded material generated per year from such wastes;

"(B) present disposal practices:

"(C) potential danger to human health and the environment from the surface runoff or leachate;

"(D) documented cases which prove or have caused danger to human health and the environment from surface runoff or leachate;

"(E) alternatives to current disposal methods:

"(F) the cost of such alternatives; and

"(G) the impact of those alternatives on the exploration for, and development and production of, crude oil and natural gas or geothermal energy.

In furtherance of this study, the Administrator shall, as he deems appropriate, review studies and other actions of other Federal agencies concerning such wastes with a view toward avoiding duplication of effort and the need to expedite such study. The Administrator shall publish a report of such and shall include appropriate findings and recommendations for Federal and non-Federal actions concerning such effects.

"(2) The Administrator shall complete the research and study and submit the report required under paragraph (1) not later than twenty-four months from the date of enactment of the Solid Waste Disposal Act Amendments of 1980. Upon completion of the study, the Administrator shall prepare a summary of the findings of the study, a plan for research, development, and demonstration respecting the findings of the study, and shall submit the findings and the study, along with any recommendations resulting from such study, to the Committee on Environment and Public Works of the United States Senate and the Committee on Interstate and Foreign Commerce of the United states House of Representatives.

"(3) There are authorized to be appropriations not to exceed $1,000,000 to carry out the provisions of this subsection.

CHAPTER II

OVERVIEW OF THE INDUSTRY

DESCRIPTION OF THE OIL AND GAS INDUSTRY

The oil and gas industry explores for, develops, and produces petroleum resources. In 1985 there were approximately 842,000 producing oil and gas wells in this country, distributed throughout 38 States. They produced 8.4 million barrels[1] of oil, 1.6 million barrels of natural gas liquids, and 44 billion cubic feet of natural gas daily. The American Petroleum Institute estimates domestic reserves at 28.4 billion barrels of oil, 7.9 billion barrels of natural gas liquids, and 193 trillion cubic feet of gas. Petroleum exploration, development, and production industries employed approximately 421,000 people in 1985.[2]

The industry is as varied as it is large. Some aspects of exploration, development, and production can change markedly from region to region and State to State. Well depths range from as little as 30 to 50 feet in some areas to over 30,000 feet in areas such as the Anadarko Basin of Oklahoma. Pennsylvania has been producing oil for 120 years; Alaska for only 15. Maryland has approximately 14 producing wells; Texas has 269,000 and completed another 25,721 in 1985 alone. Production from a single well can vary from a high of about 11,500 barrels per day (the 1985 average for wells on the Alaska North Slope) to less than 10 barrels per day for many thousands of "stripper" wells located in Appalachia and

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1 Crude oil production has traditionally been expressed in barrels. A barrel is equivalent to 5.61 ft^3, 0.158 m^3, or 42 U.S. gallons.

2 These numbers, provided to EPA by the Bureau of Land Management (BLM), are generally accepted.

the more developed portions of the rest of the country.[3] Overall, 70 percent of all U.S. oil wells are strippers, operating on the margins of profitability. Together, however, these strippers contribute 14 percent of total U.S. production--a number that appears small, yet is roughly the equivalent of the immense Prudhoe Bay field in Alaska.

Such statistics make it clear that a short discussion such as this cannot provide a comprehensive or fully accurate description of this industry. The purpose of this chapter is simply to present the terminology used in the rest of this report[4] and to provide an overview of typical exploration, development, and production methods. With this as introduction, the chapter then defines which oil and gas wastes EPA considers to be exempt within the scope of RCRA Section 8002; estimates the volumes of exempt wastes generated by onshore oil and gas operations; and presents the results of sample surveys conducted by EPA and the American Petroleum Institute to characterize the content of exempt oil and gas wastes.

Exploration and Development

Although geological and geophysical studies provide information concerning potential accumulations of petroleum, the only method that can confirm the presence of petroleum is exploratory drilling. The majority of exploratory wells are "dry" and must be plugged and abandoned. When an exploratory well does discover a commercial deposit, however, many development wells are typically needed to extract oil or gas from that reservoir.

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3 The definition of "stripper" well may vary from State to State. For example, North Dakota defines a stripper as a well that produces 10 barrels per day or less at 6,000 feet or less; 11 to 15 barrels per day from a depth of 6,001 feet to 10,000 feet; and 16 to 20 barrels per day for wells that are 10,000 feet deep.

4 A glossary of terms is also provided in Volume 3.

Exploratory and development wells are mechanically similar and generate similar wastes up to the point of production. In order to bring a field into production, however, development wells generate wastes associated with well completion and stimulation; these processes are discussed below. From 1981 to 1985, exploration and development drilling combined averaged 73,000 wells per year (API 1986). Drilling activity declined in 1986 and by mid-1987 rebounded over 1986 levels.

In the early part of the century, cable-tool drilling was the predominant method of well drilling. The up-and-down motion of a chisel-like bit, suspended by a cable, causes it to chip away the rock, which must be periodically removed with a bailer. Although an efficient technique, cable-tool drilling is limited to use in shallow, low-pressure reservoirs. Today, cable-tool drilling is used on a very limited basis in the United States, having been replaced almost entirely by rotary drilling.

Rotary drilling provides a safe method for controlling high-pressure oil/gas/water flows and allows for the simultaneous drilling of the well and removal of cuttings, making it possible to drill wells over 30,000 feet deep. Figure II-1 illustrates the process. The rotary motion provided by mechanisms on the drill rig floor turns a drill pipe or stem, thereby causing a bit on the end of the pipe to gouge and chip away the rock at the bottom of the hole. The bit itself generally has three cone-shaped wheels tipped with hardened teeth and is weighted into place by thick-walled collars. Well casing is periodically cemented into the hole, providing a uniform and stable conduit for the drill stem as it drills deeper into the hole. The casing also seals off freshwater aquifers, high-pressure zones, and other troublesome formations.

Most rotary drilling operations employ a circulation system using a water- or oil-based fluid, called "mud" because of its appearance. The

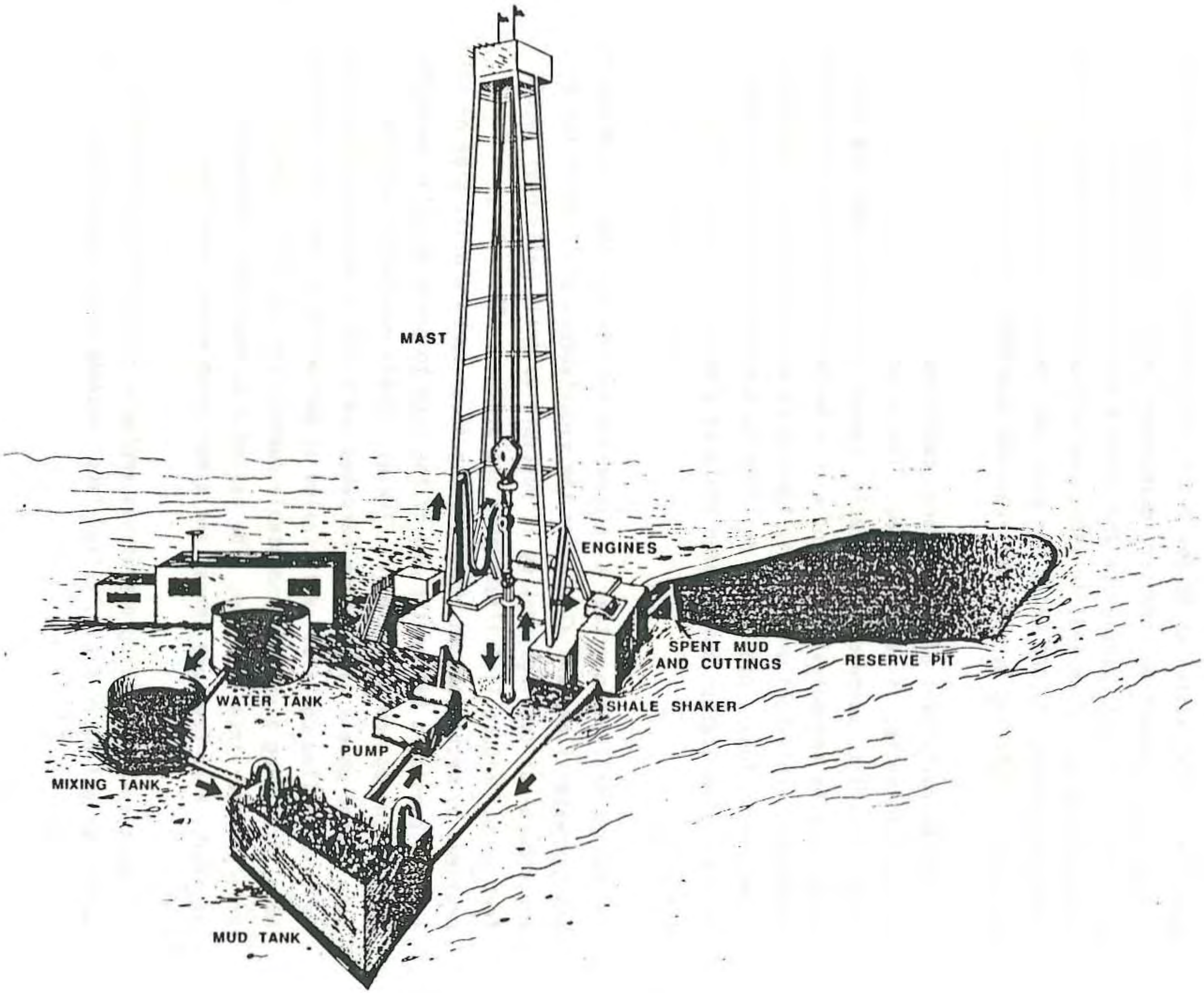

Figure II-1 Typical Rotary Drilling Rig

mud is pumped down the hollow drill pipe and across the face of the bit to provide lubrication and remove cuttings. The mud and cuttings are then pumped back up through the annular space between the drill pipe and the walls of the hole or casing. Mud is generally mixed with a weighting agent such as barite, and other mud additives, thus helping it serve several other important functions: (1) stabilizing the wellbore and preventing cave-ins, (2) counterbalancing any high-pressure oil, gas, or water zones in the formations being drilled, and (3) providing a medium to alleviate problems "downhole" (such as stuck pipe or lost circulation).

Cuttings are removed at the surface by shale shakers, desanders, and desilters; they are then deposited in the reserve pit excavated or constructed next to the rig. The reclaimed drilling mud is then recirculated back to the well. The type and extent of solids control equipment used influences how well the cuttings can be separated from the drilling fluid, and hence influences the volume of mud discharged versus how much is recirculated. Drilling mud must be disposed of when excess mud is collected, when changing downhole conditions require a whole new mud formulation, or when the well is abandoned. The reserve pit is generally used for this purpose. (Reserve pits serve multiple waste management functions. See discussion in Chapter III.) If the well is a dry hole, the drilling mud may be disposed of downhole upon abandonment.

The formation of a drilling mud for a particular job depends on types of geologic formations encountered, economics, availability, problems encountered downhole, and well data collection practices. Water-based drilling muds predominate in the United States. Colloidal materials, primarily bentonitic clay, and weighting materials, such as barite, are common constituents. Numerous chemical additives are available to give the mud precise properties to facilitate the drilling of the well; they include acids and bases, salts, corrosion inhibitors, viscosifiers, dispersants, fluid loss reducers, lost circulation materials, flocculants, surfactants, biocides, and lubricants. (See also Table III-2.)

Oil-based drilling fluids account for approximately 3 to 10 percent of the total volume of drilling fluids used nationwide. The oil base may consist of crude oil, refined oil (usually fuel oil or diesel), or mineral oil. Oil-based drilling fluid provides lubrication in directionally drilled holes, high-temperature stability in very deep holes, and protection during drilling through water-sensitive formations.

In areas where high-pressure or water-bearing formations are not anticipated, air drilling is considerably faster and less expensive than drilling with water- or oil-based fluids. (Air drilling cannot be used in deep wells.) In this process, compressed air takes the place of mud, cooling the bit and lifting the cuttings back to the surface. Water is injected into the return line for dust suppression, creating a slurry that must be disposed of. In the United States, air drilling is most commonly used in the Appalachian Basin, in southeastern Kansas/northeastern Oklahoma, and in the Four Corners area of the Southwest. Other low-density drilling fluids are used in special situations. Gases other than air, usually nitrogen, are sometimes useful. These may be dispersed with liquids or solids, creating wastes in the form of mist, foam, emulsion, suspension, or gel.

Potential producing zones are commonly measured and analyzed (logged) during drilling, a process that typically generates no waste. If hydrocarbons appear to be present, a drill stem test can tell much about their characteristics. When the test is completed, formation fluids collected in the drill pipe must be disposed of.

If tests show that commercial quantities of oil and gas are present, the well must be prepared for production or "completed." "Cased hole" completions are the most common type. First, production casing is run into the hole and cemented permanently in place. Then one or more strings of production tubing are set in the hole, productive intervals are isolated with packers, and surface equipment is installed. Actual completion involves the use of a gun or explosive charge that perforates the production casing and begins the flow of petroleum into the well.

During these completion operations, drilling fluid in the well may be modified or replaced by specialized fluids to control flow from the formation. A typical completion fluid consists of a brine solution modified with petroleum products, resins, polymers, and other chemical additives. When the well is produced initially, the completion fluid may be reclaimed or treated as a waste product that must be disposed of. For long-term corrosion protection, a packer fluid is placed into the casing/tubing annulus. Solids-free diesel oil, crude oil, produced water, or specially treated drilling fluid are preferred packer fluids.

Following well completion, oil or gas in the surrounding formations frequently is not under sufficient pressure to flow freely into the well and be removed. The formation may be impacted with indigenous material, the area directly surrounding the borehole may have become packed with cuttings, or the formation may have inherent low permeability.

Operators use a variety of stimulation techniques to correct these conditions and increase oil flow. Acidizing introduces acid into the production formation, dissolving formation matrix and thereby enlarging existing channels in carbonate-bearing rock. Hydraulic fracturing involves pumping specialized fluids carrying sand, glass beads, or similar materials into the production formation under high pressure; this creates fractures in the rock that remain propped open by the sand, beads, or similar materials when pressure is released.

Other specialized fluids may be pumped down a production well to enhance its yield; these can include corrosion inhibitors, surfactants, friction reducers, complexing agents, and cleanup additives. Although the formation may retain some of these fluids, most are returned to the surface when the well is initially produced or are slowly released over time. These fluids may require disposal, independent of disposal associated with produced water.

Drilling operations have the potential to create air pollution from several sources. The actual drilling equipment itself is typically run by large diesel engines that tend to emit significant quantities of particulates, sulfur oxides, and oxides of nitrogen, which are subject to regulation under the Clean Air Act. The particulates emitted may contain heavy metals as well as polycyclic organic matter (POMs). Particularly for deep wells, which require the most power to drill, and in large fields where several drilling operations may be in progress at the same time, cumulative diesel emissions can be important. Oil-fired turbines are also used as a source of power on newer drilling rigs. Other sources of air pollution include volatilization of light organic compounds from reserve pits and other holding pits that may be in use during drilling; these are exempt wastes. These light organics can be volatilized from recovered hydrocarbons or from solvents or other chemicals used in the production process for cleaning, fracturing, or well completion. The volume of volatile organic compounds is insignificant in comparison to diesel engine emissions.

Production

Production operations generally include all activities associated with the recovery of petroleum from geologic formations. They can be divided into activities associated with downhole operations and activities associated with surface operations. Downhole operations include primary, secondary, and tertiary recovery methods; well workovers; and well stimulation activities. Activities associated with surface operations include oil/gas/water separation, fluid treatment, and disposal of produced water. Each of these terms is discussed briefly below.

Downhole Operations

Primary recovery refers to the initial production of oil or gas from a reservoir using natural pressure or artificial lift methods, such as surface or subsurface pumps and gas lift, to bring it out of the formation and to the surface. Most reservoirs are capable of producing oil and gas by primary recovery methods alone, but this ability declines over the life of the well. Eventually, virtually all wells must employ some form of secondary recovery, typically involving injection of gas or liquid into the reservoir to maintain pressure within the producing formation. Waterflooding is the most frequently employed secondary recovery method. It involves injecting treated fresh water, seawater, or produced water into the formation through a separate well or wells.

Tertiary recovery refers to the recovery of the last portion of the oil that can be economically produced. Chemical, physical, and thermal methods are available and may be used in combination. Chemical methods involve injection of fluids containing substances such as surfactants and polymers. Miscible oil recovery involves injection of gases, such as carbon dioxide and natural gas, which combine with the oil. Thermal recovery methods include steam injection and in situ combustion (or "fire flooding"). When oil eventually reaches a production well, injected gases or fluids from secondary and tertiary recovery operations may be dissolved or carried in formation oil or water, or simply mixed with them; their removal is discussed below in conjunction with surface production operations.

Workovers, another aspect of downhole production operations, are designed to restore or increase production from wells whose flows are inhibited by downhole mechanical failures or blockages, such as sand or paraffin deposits. Fluids circulated into the well for this purpose must be compatible with the formation and must not adversely affect permeability. They are similar to completion fluids, described earlier. When the well is put back into production, the workover fluid may be reclaimed or disposed of.

Other chemicals may be periodically or continuously pumped down a production well to inhibit corrosion, reduce friction, or simply keep the well flowing. For example, methanol may be pumped down a gas well to keep it from becoming plugged with ice.

Surface Operations

Surface production operations generally include gathering of the produced fluids (oil, gas, gas liquids, and water) from a well or group of wells and separation and treatment of the fluids. See Figures II-2, II-3, and II-4. As producing reservoirs are depleted, their water/oil ratios may increase steeply. New wells may produce little if any water; stripper wells may vary greatly in the volume of water they produce. Some may produce more than 100 barrels of water for every barrel of oil, particularly if the wells are subject to waterflooding operations.

Virtually all of this water must be removed before the product can be transferred to a pipeline. (The maximum water content allowed is generally less than 1 percent.) The oil may also contain completion or workover fluids, stimulation fluids, or other chemicals (biocides, fungicides) used as an adjunct to production. Some oil/water mixtures may be easy to separate, but others may exist as fine emulsions that do

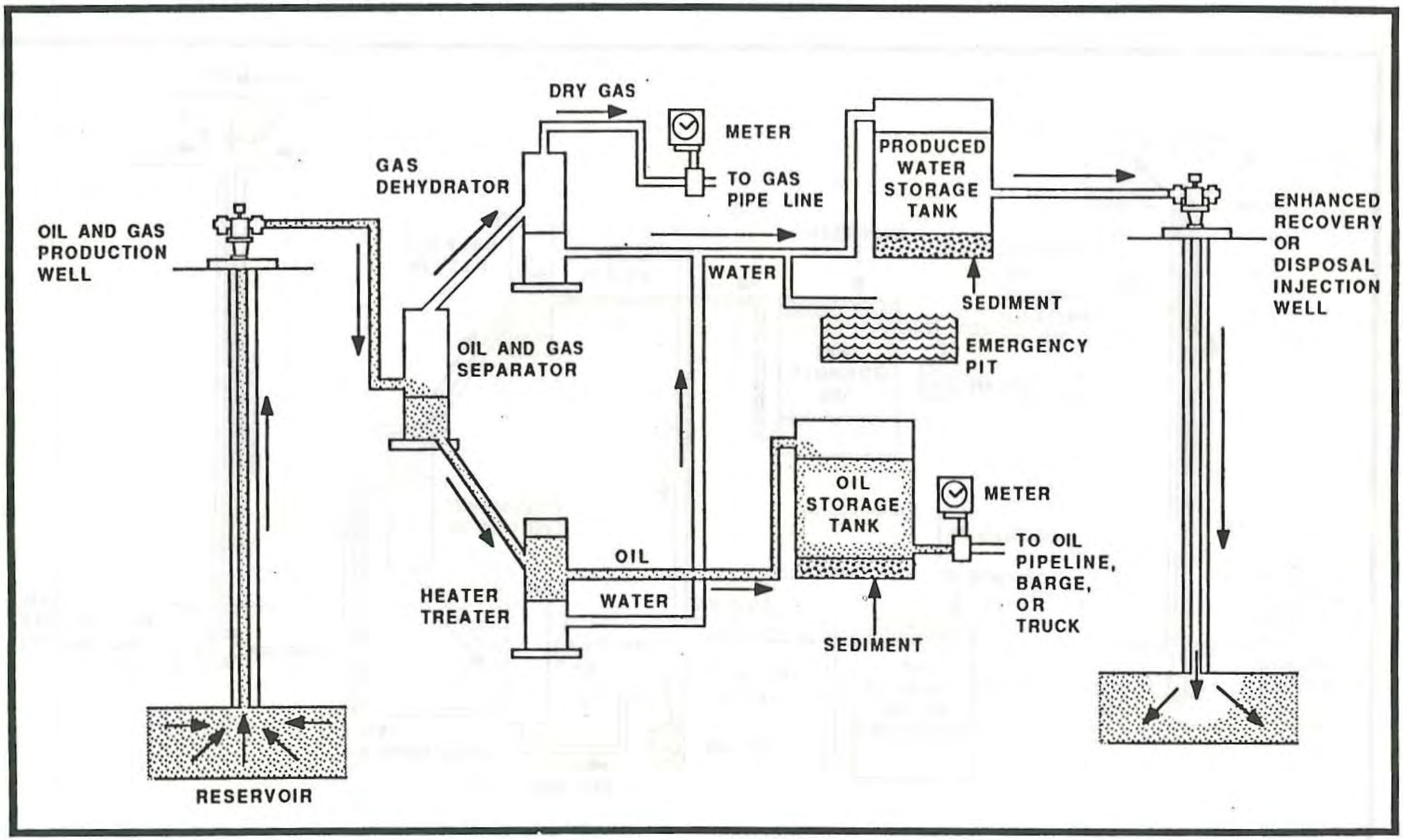

Figure II-2 Typical Production Operation, Showing Separation of Oil, Gas, and Water

Produced waters are not always injected as indicated in this figure. Produced water may be trucked to central treatment and disposal facilities, discharged into disposal pits, discharged to surface or coastal waters, or used for beneficial or agricultural use.

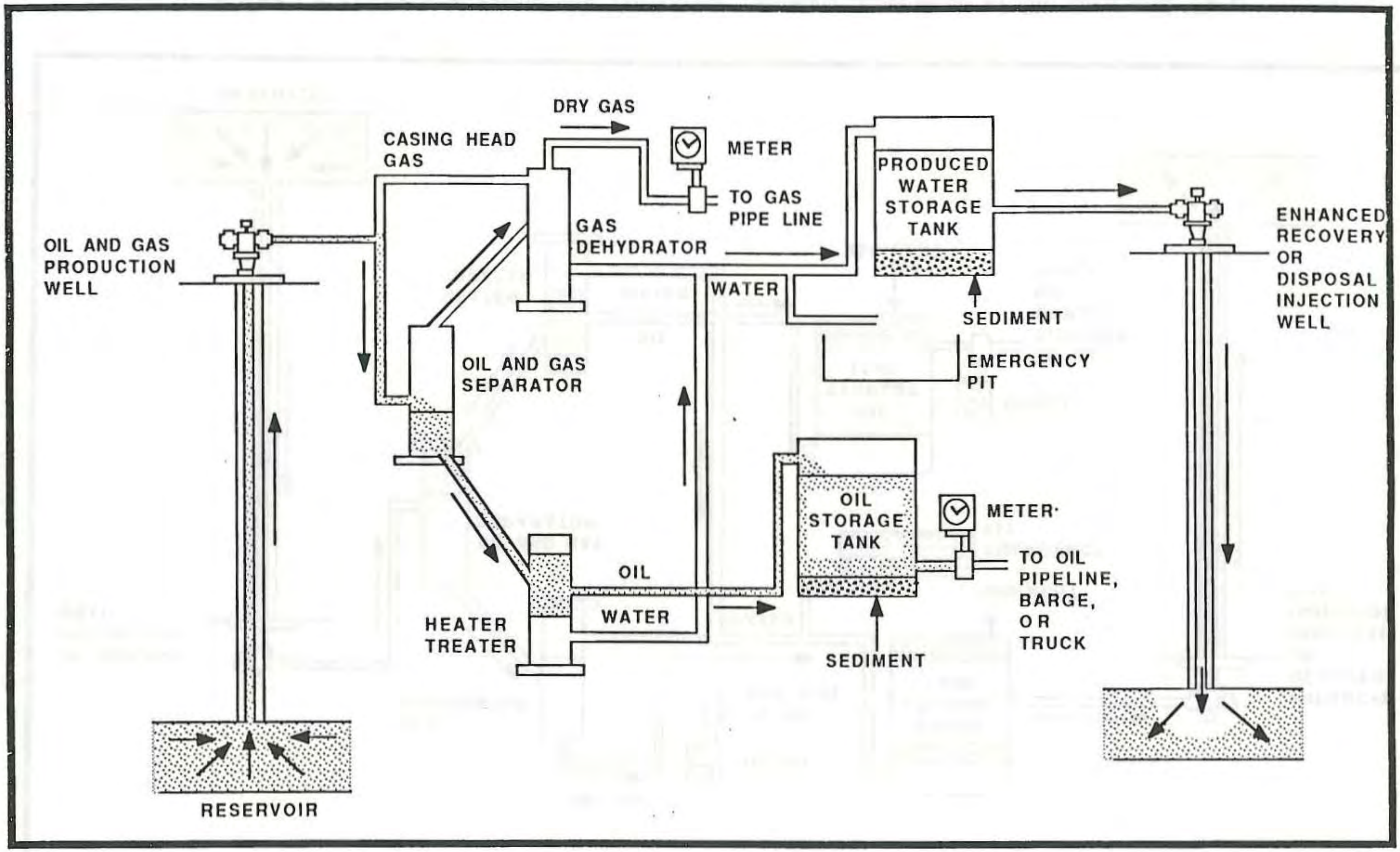

Figure II-3 Oil Production With Average H_2O Production With Dissolved/Associated Gas

Produced waters are not always injected as indicated in this figure. Produced water may be trucked to central treatment and disposal facilities, discharged into disposal pits, discharged to surface or coastal waters, or used for beneficial or agricultural use.

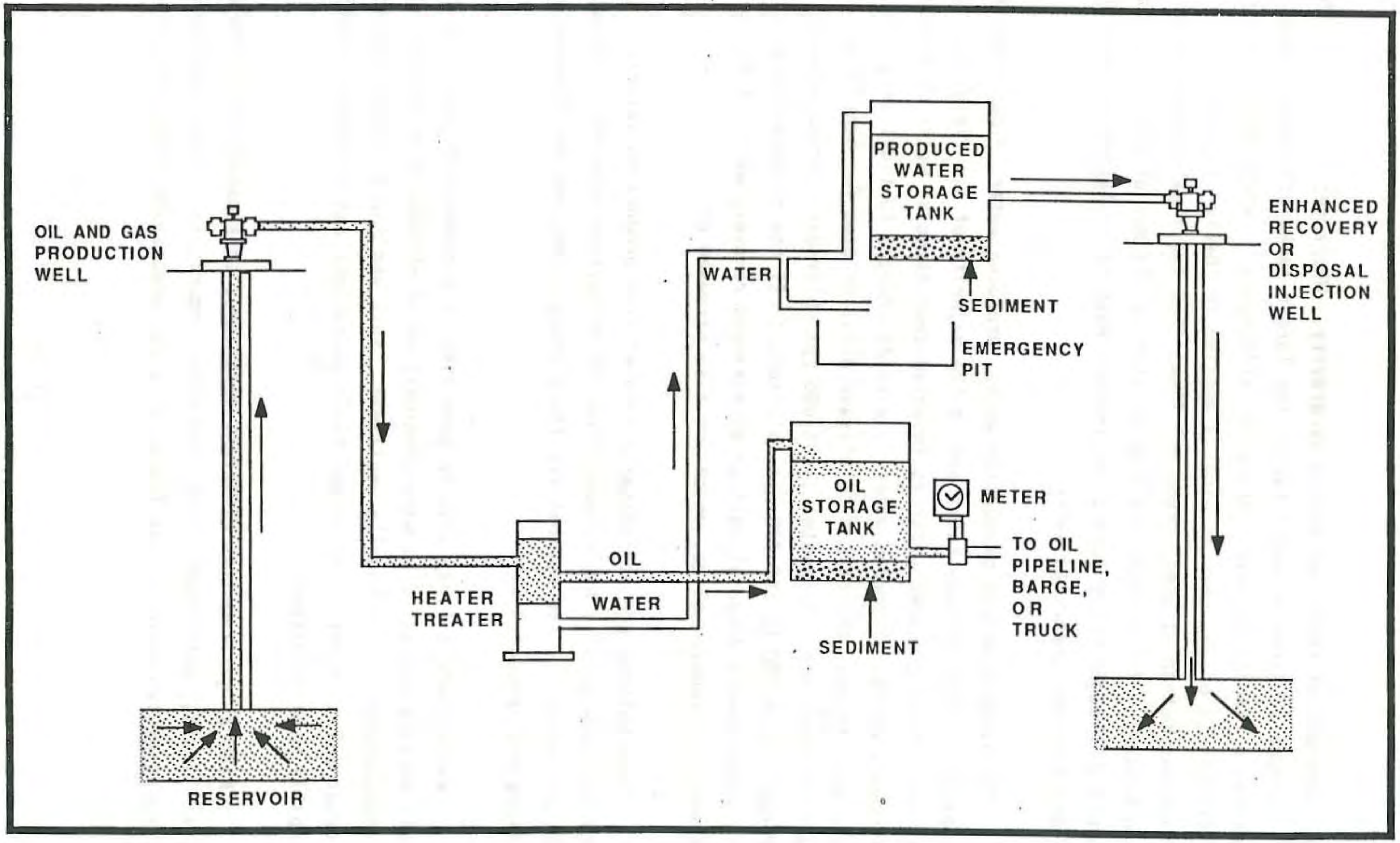

Figure II-4 High Oil/H_2O Ratio Without Significant Dissolved/Associated Gas

Produced waters are not always injected as indicated in this figure. Produced water may be trucked to central treatment and disposal facilities, discharged into disposal pits, discharged to surface or coastal waters, or used for beneficial or agricultural use.

not separate of their own accord by gravity. Where settling is possible, it is done in large or small tanks, the larger tanks affording longer residence time to increase separation efficiency. Where emulsions are difficult to break, heat is usually applied in "heater treaters." Whichever method is used, crude oil flows from the final separator to stock tanks. The sludges and liquids that settle out of the oil as tank bottoms throughout the separation process must be collected and discarded along with the separated water.

The largest volume production waste, produced water, flows from the separators into storage tanks and in the majority of oil fields is highly saline. Most produced water is injected down disposal wells or enhanced recovery wells. Produced water is also discharged to tidal areas and surface streams, discharged to storage pits, or used for beneficial or agricultural use. (Seawater is 35,000 ppm chlorides. Produced water can range from 5,000 to 180,000 ppm chlorides.) If the produced water is injected down a disposal well or an enhanced recovery well, it may be treated to remove solids, which are also disposed of.

Tank bottoms are periodically removed from production vessels. Tank bottoms are usually hauled away from the production site for disposal. Occasionally, if the bottoms are fluid enough, they may be disposed of along with produced water.

Waste crude oil may also be generated at a production site. If crude oil becomes contaminated with chemicals or is skimmed from surface impoundments, it is usually reclaimed. Soil and gravel contaminated by crude oil as a result of normal field operations and occasional leaks and spills require disposal.

Natural gas requires different techniques to separate out crude oil, gas liquids, entrained solids, and other impurities. These separation processes can occur in the field, in a gas processing plant, or both, but more frequently occur at an offsite processing plant. Crude oil, gas liquids, some free water, and entrained solids can be removed in conventional separation vessels. More water may be removed by any of several dehydration processes, frequently through the use of glycol, a liquid dessicant, or various solid dessicants. Although these separation media can generally be regenerated and used again, they eventually lose their effectiveness and must be disposed of.

Both crude oil and natural gas may contain the highly toxic gas hydrogen sulfide, which is an exempt waste. (Eight hundred ppm in air is lethal to humans and represents an occupational hazard, but not an ambient air toxics threat to human health offsite.) At plants where hydrogen sulfide is removed from natural gas, sulfur dioxide (SO_2) release results. (EPA requires compliance with the National Ambient Air Quality Standards (NAAQS) for sulfur dioxide; DOI also has authority to regulate these emissions.) Sulfur is often recovered from the hydrogen sulfide (H_2S) as a commercial byproduct. H_2S dissolved in crude oil does not pose any danger, but when it is produced at the wellhead in gaseous form, it poses serious occupational risks through possible leaks or blowouts. These risks are also present later in the production process when the H_2S is separated out in various "sweetening" processes. The amine, iron sponge, and selexol processes are three examples of commercial processes for removing acid gases from natural gas. Each H_2S removal process results in spent or waste separation media, which must be disposed of. EPA did not sample hydrogen sulfide and sulphur dioxide emissions because of their relatively low volume and infrequency of occurrence.

Gaseous wastes are generated from a variety of other production-related operations. Volatile organic compounds may also be released from minute leaks in production equipment or from pressure vents on separators and storage tanks. When a gas well needs to be cleaned out, it may be produced wide open and vented directly to the atmosphere.

Emissions from volatile organic compounds are exempt under Section 3001(b)(2)(A) of RCRA and represent a very low portion of national air emissions. Enhanced oil recovery steam generators may burn crude oil as fuel, thereby creating air emissions. These wastes are nonexempt.

DEFINITION OF EXEMPT WASTES

The following discussion presents EPA's tentative definition of the scope of the exemption.

Scope of the Exemption

The current statutory exemption originated in EPA's proposed hazardous waste regulations of December 18, 1978 (43 FR 58946). Proposed 40 CFR 250.46 contained standards for "special wastes"--reduced requirements for several types of wastes that are produced in large volume and that EPA believed may be lower in toxicity than other wastes regulated as hazardous wastes under RCRA. One of these categories of special wastes was "gas and oil drilling muds and oil production brines."

In the RCRA amendments of 1980, Congress exempted most of these special wastes from the hazardous waste requirements of RCRA Subtitle C, pending further study by EPA. The oil and gas exemption, Section 3001(b)(2)(A), is directed at "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas." The legislative history does not elaborate on the definition of drilling fluids or produced waters, but it does discuss "other wastes" as follows:

> The term "other wastes associated" is specifically included to designate waste materials intrinsically derived from the primary field operations associated with the exploration, development, or production of crude oil and natural gas. It would cover such substances as: hydrocarbon bearing soil in and around related facilities; drill cuttings; and materials (such as hydrocarbons,

water, sand and emulsion) produced from a well in conjunction with crude oil and natural gas and the accumulated material (such as hydrocarbons, water, sand, and emulsion) from production separators, fluid treating vessels, storage vessels, and production impoundments. (H.R. Rep No. 1444, 96th Cong., 2d Sess. at 32 (1980)).

The phrase "intrinsically derived from the primary field operations..." is intended to differentiate exploration, development, and production operations from transportation (from the point of custody transfer or of production separation and dehydration) and manufacturing operations.

In order to arrive at a clear working definition of the scope of the exemption under Section 8002(m), EPA has used these statements in conjunction with the statutory language of RCRA as a basis for making the following assumptions about which oil and gas wastes should be included in the present study.

- Although the legislative history underlying the oil and gas exemption is limited to "other wastes associated with the exploration development or production of crude oil or natural gas," the Agency believes that the rationale set forth in that history is equally applicable to produced waters and drilling fluids. Therefore, in developing criteria to define the scope of the Section 3001(b)(2) exemption, the Agency has applied this legislative history to produced waters and drilling fluids.
- The potential exists for small volume nonexempt wastes to be mixed with exempt wastes, such as reserve pit contents. EPA believes it is desirable to avoid improper disposal of hazardous (nonexempt) wastes through dilution with nonhazardous exempt wastes. For example, unused pipe dope should not be disposed of in reserve pits. Some residual pipe dope, however, will enter the reserve pit as part of normal field operations; this residual pipe dope does not concern EPA. EPA is undecided as to the proper disposal method for some other waste streams, such as rigwash that often are disposed of in reserve pits.

Using these assumptions, the test of whether a particular waste qualifies under the exemption can be made in relation to the following three separate criteria. No one criterion can be used as a standard when defining specific waste streams that are exempt. These criteria are as follows.

1. Exempt wastes must be associated with measures (1) to locate oil or gas deposits, (2) to remove oil or natural gas from the ground, or (3) to remove impurities from such substances, provided that the purification process is an integral part of primary field operations.[5]

2. Only waste streams intrinsic to the exploration for, or the development and production of, crude oil and natural gas are subject to exemption. Waste streams generated at oil and gas facilities that are not uniquely associated with the exploration, development, or production activities are <u>not</u> exempt. (Examples would include spent solvents from equipment cleanup or air emissions from diesel engines used to operate drilling rigs.)

   Clearly those substances that are extracted from the ground or injected into the ground to facilitate the drilling, operation, or maintenance of a well or to enhance the recovery of oil and gas are considered to be uniquely associated with primary field operations. Additionally, the injection of materials into the pipeline at the wellhead which keep the lines from freezing or which serve as solvents to prevent paraffin accumulation is intrinsically associated with primary field operations. With regard to injection for enhanced recovery, the injected materials must function primarily to enhance recovery of oil and gas and must be recognized by the Agency as being appropriate for enhanced recovery. An example would be produced water. In this context, "primarily functions" means that the main reason for injecting the materials is to enhance recovery of oil and gas rather than to serve as a means for disposing of those materials.

3. Drilling fluids, produced waters, and other wastes intrinsically derived from primary field operations associated with the exploration, development, or production of crude oil, natural gas, or geothermal energy are subject to exemption. Primary field operations encompass production-related activities but not transportation or manufacturing activities. With respect to oil production, primary field operations encompass those activities occurring at or near the wellhead, but prior to the transport of oil from an individual field facility or a centrally located facility to a carrier (i.e., pipeline or trucking concern) for transport to a refinery or to a refiner. With respect to natural gas production, primary field operations are those activities occurring at or near the wellhead or at the gas plant but prior to that point at which the gas is transferred from an individual field facility, a centrally located facility, or a gas plant to a carrier for transport to market.

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[5] Thus, wastes associated with such processes as oil refining, petrochemical-related manufacturing, or electricity generation are not exempt because those processes do not occur at the primary field operations.

Primary field operations may encompass the primary, secondary, and tertiary production of oil or gas. Wastes generated by the transportation process itself are not exempt because they are not intrinsically associated with primary field operations. An example would be pigging waste from pipeline pumping stations.

Transportation for the oil and gas industry may be for short or long distances. Wastes associated with manufacturing are not exempt because they are not associated with exploration, development, or production and hence are not intrinsically associated with primary field operations. Manufacturing (for the oil and gas industry) is defined as any activity occurring within a refinery or other manufacturing facility the purpose of which is to render the product commercially saleable.

Using these definitions, Table II-1 presents definitions of exempted wastes as defined by EPA for the purposes of this study. Note that this is a partial list only. Although it includes all the major streams that EPA has considered in the preparation of this report, others may exist. In that case, the definitions listed above would be applied to determine their status under RCRA.

Waste Volume Estimation Methodology

Information concerning volumes of wastes from oil and gas exploration, development, and production operations is not routinely collected nationwide, making it necessary to develop methods for estimating these volumes by indirect methods in order to comply with the Section 8002(m) requirement to present such estimates to Congress. For this study, estimates were compiled independently by EPA and by the American Petroleum Institute (API) using different methods. Both are discussed below.

Estimating Volumes of Drilling Fluids and Cuttings

EPA considered several different methodologies for determining volume estimates for produced water and drilling fluid.

Table II-1 Partial List of Exempt and Nonexempt Wastes

EXEMPT WASTES

Drill cuttings

Drilling fluids

Well completion, treatment, and stimulation fluids

Packing fluids

Sand, hydrocarbon solids, and other deposits removed from production wells

Pipe scale, hydrocarbon solids, hydrates, and other deposits removed from piping and equipment

Hydrocarbon-bearing soil

Pigging wastes from gathering lines

Wastes from subsurface gas storage and retrieval

Basic sediment and water and other tank bottoms from storage facilities and separators

Produced water

Constituents removed from produced water before it is injected or otherwise disposed of

Accumulated materials (such as hydrocarbons, solids, sand, and emulsion) from production separators, fluid-treating vessels, and production impoundments that are not mixed with separation or treatment media

Drilling muds from offshore operations

Appropriate fluids injected downhole for secondary and tertiary recovery operations

Liquid hydrocarbons removed from the production stream but not from oil refining

Gases removed from the production stream, such as hydrogen sulfide, carbon dioxide, and volatilized hydrocarbons

Materials ejected from a production well during the process known as blowing down a well

Waste crude oil from primary field operations

Light organics volatilized from recovered hydrocarbons or from solvents or other chemicals used for cleaning, fracturing, or well completion

NONEXEMPT WASTES

Waste lubricants, hydraulic fluids, motor oil, and paint

Waste solvents from clean-up operations

Off-specification and unused materials intended for disposal

Incinerator ash

Pigging wastes from transportation pipelines

Table II-1

Sanitary wastes, trash, and gray water

Gases, such as SOx, NOx, and particulates from gas turbines or other machinery

Drums (filled, partially filled, or cleaned) whose contents are not intended for use

Waste iron sponge, glycol, and other separation media

Filters

Spent catalysts

Wastes from truck- and drum-cleaning operations

Waste solvents from equipment maintenance

Spills from pipelines or other transport methods

EPA's estimates: For several regions of the country, estimates of volumes of drilling fluids and cuttings generated from well drilling operations are available on the basis of waste volume per foot of well drilled. Estimates range from 0.2 barrel/foot (provided by the West Virginia Dept. of Natural Resources) to 2.0 barrels/foot (provided by NL Baroid Co. for Cotton Valley formation wells in Panola County, Texas). EPA therefore considered the possibility of using this approach nationwide. If it were possible to generate such estimates for all areas of the country, including allowances for associated wastes such as completion fluids and waste cement, nationwide figures would then be comparatively easy to generate. They could be based on the total footage of all wells drilled in the U.S., a statistic that is readily available from API.

This method proved infeasible, however, because of a number of complex factors contributing to the calculation of waste-per-foot estimates that would be both comprehensive and valid for all areas of the country. For instance, the use of solids control equipment at drilling sites, which directly affects waste generation, is not standardized. In addition, EPA would have to differentiate among operations using various drilling fluids (oil-based, water-based, and gas-based fluids). These and other considerations caused the Agency to reject this method of estimating volumes of drilling-related wastes.

Another methodology would be to develop a formal model for estimating waste volumes based on all the factors influencing the volume of drilling waste produced. These factors would include total depth drilled, geologic formations encountered, drilling fluid used, solids control equipment used, drilling problems encountered, and so forth. Such a model could then be applied to a representative sample of wells drilled nationwide, yielding estimates that could then be extrapolated to produce nationwide volumes estimates.

This method, too, was rejected as infeasible. It would have required access to data derived from the driller's logs and mud logs maintained at individual well sites, which would have been very difficult to acquire. Beyond this, other data and analytical needs for building such a model proved to be beyond the resources available for the project.

With these methodologies unavailable, EPA developed its estimates by equating the wastes generated from a drilling operation with the volume of the reserve pit constructed to service the well. Typically, each well is served by a single reserve pit, which is used primarily for either temporary or permanent disposal of drilling wastes. Based on field observations, EPA made the explicit assumption that reserve pits are sized to accept the wastes anticipated from the drilling operation. The Agency then collected information on pit sizes during the field sampling program in 1986 (discussed later in this chapter), from literature searches, and by extensive contact with State and Federal regulatory personnel.

EPA developed three generic pit sizes (1,984-, 22,700-, and 87,240-barrel capacity) to represent the range of existing pits and assigned each State a percent distribution for each pit size based on field observation and discussion with selected State and industry personnel. For example, from the data collected, Utah's drilling sites were characterized as having 35 percent small pits, 50 percent medium pits, and 15 percent large pits. Using these State-specific percent distributions, EPA was then able to readily calculate an estimate of annual drilling waste volumes per year for each State. Because Alaska's operations are generally larger than operations in the other oil- and gas-producing States, Alaska's generic pit sizes were different (55,093- and 400,244-barrel capacity.)

Although the EPA method is relatively simple, relying on a well site feature that is easily observable (namely, the reserve pit), the method does have several disadvantages. It does not explicitly account for waste volume increases and decreases due to evaporation, percolation, and rainwater collection. The three generic pit sizes may not adequately represent the wide range of pit sizes used for drilling, and they all assume that the total volume of each reserve pit, minus a nominal 2 feet of freeboard, will be used for wastes. Finally, the information collected to determine the percent distributions of pit sizes within States may not adequately characterize the industry, and adjusting the distribution would require gathering new information or taking a new survey. All of these uncertainties detract from the accuracy of a risk assessment or an economic impact analysis used to evaluate alternative waste management techniques.

<u>The American Petroleum Institute's estimates:</u> As the largest national oil trade organization, the API routinely gathers and analyzes many types of information on the oil and gas industry. In addition, in conducting its independent estimates of drilling waste volumes, API was able to conduct a direct survey of operators in 1985 to request waste volume data--a method that was unavailable to EPA because of time and funding limitations. API sent a questionnaire to a sample of operators nationwide, asking for estimated volume data for drilling muds and completion fluids, drill cuttings, and other associated wastes discharged to the reserve pit. Completed questionnaires were received for 693 individual wells describing drilling muds, completion fluids, and drill cuttings; 275 questionnaires also contained useful information concerning associated wastes. API segregated the sampled wells so that it could characterize drilling wastes within each of 11 sampling zones used in this study and within each of 4 depth classes. Since API maintains a data base on basic information on all wells drilled in the U.S., including location and depth, it was able to estimate a volume of wastes for the more than 65,000 wells drilled in 1985. The API survey does have

several significant limitations. Statistical representativeness of the survey is being analyzed by EPA. Respondents to the survey were primarily large oil companies. The survey was accompanied by a letter that may have influenced the responses. Also, EPA experience with operators indicates that they may underestimate reserve pit volumes.

Even though volumetric measurement and statistical analysis represent the preferred method for estimating drilling waste volumes, the way in which API's survey was conducted and the data were analyzed may have some drawbacks. Operators were asked to estimate large volumes of wastes, which are added slowly to the reserve pit and are not measured. Because the sample size is small in comparison to the population, it is questionable whether the sample is an unbiased representation of the drilling industry.

Estimating Volumes of Produced Water

By far the largest volume production waste from oil and gas operations is produced water. Of all the wastes generated from oil and gas operations, produced water figures are reported with the most frequency because of the reporting requirements under the Underground Injection Control (UIC) and National Pollution Discharge Elimination System (NPDES) programs.

EPA's estimates: Because produced water figures are more readily available than drilling waste data, EPA conducted a survey of the State agencies of 33 oil- and gas-producing States, requesting produced water data from injection reports, production reports, and hauling reports. For those States for which this information was not available, EPA derived estimates calculated from the oil/water ratio from surrounding States (this method used for four States) or derived estimates based on information provided by State representatives (this method used for six States).

API's estimates: In addition to its survey of drilling wastes, API conducted a supplemental survey to determine total volumes of produced water on a State-by-State basis. API sent a produced water survey form to individual companies requesting 1985 crude oil and condensate volumes and produced water volumes and distribution. Fourteen operators in 23 States responded. Because most of the operators were active in more than one State, API was able to include a total of 170 different survey points. API then used these data to generate water-to-oil ratios (number of barrels of water produced with each barrel of oil) for each operator in each State. By extrapolation, the results of the survey yield an estimate of the total volume of produced water on a statewide basis; the statewide estimated produced water volume total is simply the product of the estimated State ratio (taken from this survey) and the known total oil production for the State. API reports this survey method to have a 95 percent confidence level for produced water volumes. No standard deviation was reported with this confidence level.

For most States, the figure generated by this method agrees closely with the figure arrived at by EPA in its survey of State agencies in 33 oil-producing States. For a few States, however, the EPA and API numbers are significantly different; Wyoming is an example. Since most of the respondents to the API survey were major companies, their production operations may not be truly representative of the industry as a whole. Also, the API method did not cover all of the States covered by EPA.

Neither method can be considered completely accurate, so judgment is needed to determine the best method to apply for each State. Because the Wyoming State agency responsible for oil and gas operations believes that the API number is greatly in error, the State number is used in this report. Also, since the API survey did not cover many of the States in the Appalachian Basin, the EPA numbers for all of the Appalachian Basin States are used here. In all other cases, however, the API-produced water volume numbers, which were derived in part from a field survey, are believed to be more accurate than EPA numbers and are therefore used in this report.

Waste Volume Estimates

Drilling waste volumes for 1985, calculated by both the EPA and API methods, appear in Table II-2. Although the number of wells drilled for each State differs between the two methods, both methods fundamentally relied upon API data. The EPA method estimates that 2.44 billion barrels of waste were generated from the drilling of 64,508 wells, for an average of 37,902 barrels of waste per well. The API method estimates that 361 million barrels of waste were generated from the drilling of 69,734 wells, for an average of 5,183 barrels of waste per well. EPA has reviewed API's survey methodology and believes the API method is more reliable in predicting actual volumes generated. For the purposes of this report, EPA will use the API estimates for drilling waste volumes.

Produced water volumes for 1985, calculated by both the EPA and API methods, appear in Table II-3. The EPA method estimates 11.7 billion barrels of produced water. The API method estimates 20.9 billion barrels of produced water.

CHARACTERIZATION OF WASTES

In support of this study, EPA collected samples from oil and gas exploration, development, and production sites throughout the country and analyzed them to determine their chemical composition. The Agency designed the sampling plan to ensure that it would cover the country's wide range of geographic and geologic conditions and that it would randomly select individual sites for study within each area (USEPA 1987). One hundred one samples were collected from 49 sites in 26 different locations. Operations sampled included centralized treatment facilities, central disposal facilities, drilling operations, and production facilities. For a more detailed discussion of all aspects of EPA's sampling program, see USEPA 1987.

Table II-2 Estimated U.S. Drilling Waste Volumes, 1985

State	EPA method Number of wells drilled	Volume[a] 1,000 bbl	API method Number of wells drilled	Volume[b] 1,000 bbl
Alabama	343	15,179	367	5,994
Alaska	206	4,118	242	1,816
Arizona	3	56	3	23
Arkansas	975	43,147	1,034	8,470
California	3,038	82,276	3,208	4,529
Colorado	1,459	27,249	1,578	8,226
Florida	21	929	21	1,068
Georgia	NC[c]	NC	1	2
Idaho	NC	NC	3	94
Illinois	2,107	57,063	2,291	2,690
Indiana	910	24,645	961	1,105
Iowa	NC	NC	1	1
Kansas	5,151	96,818	5,560	17,425
Kentucky	2,141	8,683	2,482	4,874
Louisiana	4,645	205,954	4,908	46,726
Maryland	85	345	91	201
Michigan	823	22,289	870	3,866
Mississippi	568	25,136	594	14,653
Missouri	22	596	23	18
Montana	591	36,302	623	4,569
Nebraska	261	4,906	282	761
Nevada	34	1,070	36	335
New Mexico	1,694	31,638	1,780	13,908
New York	395	1,602	436	1,277
North Dakota	485	9,116	514	4,804
Ohio	3,413	13,842	3,818	8,139
Oklahoma	6,978	383,581	7,690	42,547
Oregon	5	135	5	5
Pennsylvania	2,466	10,001	2,836	8,130

Table II-2 (continued)

State	EPA method Number of wells drilled	EPA method Volume[a] 1,000 bbl	API method Number of wells drilled	API method Volume[b] 1,000 bbl
South Dakota	44	827	49	289
Tennessee	169	685	228	795
Texas	22,538	1,238,914	23,915	133,014
Utah	332	6,201	364	4,412
Virginia	85	345	91	201
Washington	NC[c]	NC[c]	4	15
West Virginia	1,188	4,818	1,419	3,097
Wyoming	1,409[d]	86,546[d]	1,497	13,528
U.S. Total	64,499	2,444,667	69,734	361,406

[a] Based on total available reserve pit volume, assuming 2 ft of freeboard (ref.).
[b] Based on total volume of drilling muds, drill cuttings, completion fluids, circulated cement, formation testing fluids, and other water and solids.
[c] Not calculated.
[d] EPA notes that for Wyoming, the State's numbers are 1,332 and 11,988,000, respectively.

Table II-3 Estimated U.S. Produced Water Volumes, 1985

State	EPA volumes 1,000 bbl	EPA volumes Source	API volumes 1,000 bbl	API volumes Source
Alabama	34,039	a	87,619	g
Alaska	112,780	b	97,740	g
Arizona	288	b	149	g
Arkansas	226,784	b	184,536	g
California	2,553,326	b	2,846,978	g
Colorado	154,255	d	388,661	g
Florida	85,052	b	64,738	g
Illinois	8,560	e	1,282,933	g
Indiana	5,846	d	--	h
Kansas	1,916,250	f	999,143	g
Kentucky	16,055	d	90,754	g
Louisiana	794,030	f	1,346,675	g
Maryland	0	b	---	h
Michigan	64,046	b	76,440	g
Mississippi	361,038	e	318,666	g
Missouri	2,177	a	--	h
Montana	159,343	b	223,558	g
Nebraska	73,411	b	164,688	g
Nevada	3,693	a	--	h
New Mexico	368,249	e	445,265	g
New York	4,918	e	--	h
North Dakota	88,529	b	59,503	g
Ohio	13,688	e	--	h
Oklahoma	1,627,390	f	3,103,433	g
Oregon	33	b	--	h
Pennsylvania	31,131	f	--	h
South Dakota	3,127	b	5,155	g
Tennessee	800	f	--	h
Texas	2,576,000	e	7,838,783	g
Utah	126,000	e	260,661	g
Virginia	0	b	--	h
West Virginia	7,327	d	2,844	g
Wyoming	253,476*	f	985,221	g
U.S. Total	11,671,641		20,873,243**	

Sources:
- a. Injection Reports
- b. Production Reports
- c. Hauling Reports
- d. Estimate calculated from water/oil ratio from surrounding States
- e. Estimate calculated from water/oil ratio from other years for which data were available
- f. Estimate calculated from information provided by State representative. See Table I-8, (Westec, 1987) to explain footnotes a-f
- g. API industry survey
- h. Not surveyed

* Wyoming states that 1,722,599,614 barrels of produced water were generated in the State in 1985. For the work done in Chapter VI, the State's numbers were used.

** Includes only States surveyed.

Central pits and treatment facilities receive wastes from numerous oil and gas field operations. Since large geographic areas are serviced by these facilities, the facilities tend to be very large; one pit in Oklahoma measured 15 acres and was as deep as 50 feet in places. Central pits are used for long-term waste storage and incorporate no treatment of pit contents. Typical operations accept drilling waste only, produced waters only, or both. Long-term, natural evaporation can concentrate the chemical constituents in the pit. Central treatment and disposal facilities are designed for reconditioning and treating wastes to allow for discharge or final disposal. Like central pits, central treatment facilities can accept drilling wastes only, produced water only, or both.

Reserve pits are used for onsite disposal of waste drilling fluids. These reserve pits are usually dewatered and backfilled. Waste byproducts present at production sites include saltwater brines (called produced waters), tank bottom sludge, and "pigging wax," which can accumulate in the gathering lines.

Extracts from these samples were prepared both directly and following the proposed EPA Toxicity Characteristic Leaching Procedure (TCLP). They were analyzed for organic compounds, metals, classical wet chemistry parameters, and certain other analytes.

API conducted a sampling program concurrent with EPA's. API's universe of sites was slightly smaller than EPA's, but where they overlapped, the results have been compared. API's methodology was designed to be comparable to that used by EPA, but API's sampling and analytical methods, including quality assurance and quality control procedures, varied somewhat from EPA's. These dissimilarities can lead to different analytical results. For a more detailed discussion of all aspects of API's sampling program, see API 1987.

Sampling Methods

Methods used by EPA and by API are discussed briefly below, with emphasis placed on EPA's program.

EPA Sampling Procedures

Pit sampling: All pit samples were composited grab samples. The EPA field team took two composited samples for each pit--one sludge sample and one supernatant sample. Where the pit did not contain a discrete liquid phase, only a sludge sample was taken. Sludge samples are defined by EPA for this report as tank bottoms, drilling muds, or other samples that contains a significant quantity of solids (normally greater than 1 percent). EPA also collected samples of drilling mud before it entered the reserve pit.

Each pit was divided into four quadrants, with a sample taken from the center of each quadrant, using either a coring device or a dredge. The coring device was lined with Teflon or glass to avoid sample contamination. This device was preferred because of its ease of use and deeper penetration. The quadrant samples were then combined to make a single composite sample representative of that pit.

EPA took supernatant samples at each of the four quadrant centers before collecting the sludge samples, using a stainless steel liquid thief sampler that allows liquid to be retrieved from any depth. Samples were taken at four evenly spaced depths between the liquid surface and the sludge-supernatant interface. EPA followed the same procedure at each of the sampling points and combined the results into a single composite for each site.

To capture volatile organics, volatile organic analysis (VOA) vials were filled from the first liquid grab sample collected. All other sludge and liquid samples were composited and thoroughly mixed and had any foreign material such as stones and other visible trash removed prior to sending them to the laboratory for analysis (USEPA 1987).

Produced water: To sample produced water, EPA took either grab samples from process lines or composited samples from tanks. Composite samples were taken at four evenly spaced depths between the liquid surface and the bottom of the tank, using only one sampling point per tank. Storage tanks that were inaccessible from the top had to be sampled from a tap at the tank bottom or at a flow line exiting the tank. For each site location, EPA combined individual samples into a single container to create the total liquid sample for that location. EPA mixed all composited produced water samples thoroughly and removed visible trash prior to transport to the laboratory (USEPA 1987).

Central treatment facilities: Both liquid and sludge samples were taken at central treatment facilities. All were composited grab samples using the same techniques described above for pits, tanks, or process lines (USEPA 1987).

API Sampling Methods

The API team divided pits into six sections and sampled in an "S" curve pattern in each section. There were 30 to 60 sample locations depending upon the size of the pit. API's sampling device was a metal or PVC pipe, which was driven into the pit solids. When the pipe could not be used, a stoppered jar attached to a ridged pole was used. Reserve pit supernatant was sampled using weighted bottles or bottom filling devices. Produced waters were usually sampled from process pipes or valves. API did not sample central treatment facilities (API 1987).

Analytical Methods

As for sampling methods, analytical methods used by EPA and by API were somewhat different. Each is briefly discussed below.

EPA Analytical Methods

EPA analyzed wastes for the RCRA characteristics in accordance with the Office of Solid Waste test methods manual (SW-846). In addition, since the Toxicity Characteristic Leaching Procedure (TCLP) has been proposed to be a RCRA test, EPA used that analytical procedure for certain wastes, as appropriate. EPA also used EPA methods 1624 and 1625, isotope dilution methods for organics, which have been determined to be scientifically valid for this application.

EPA's survey analyzed 444 organic compounds, 68 inorganics, 19 conventional contaminants, and 3 RCRA characteristics for a total of 534 analytes. Analyses performed included gas and liquid chromatography, atomic absorption spectrometry and mass spectrometry, ultraviolet detection method, inductively coupled plasma spectrometry, and dioxin and furan analysis. All analyses followed standard EPA methodologies and protocols and included full quality assurance/quality control (QA/QC) on certain tests (USEPA 1987).

Of these 534 analytes, 134 were detected in one or more samples. For about half of the sludge samples, extracts were taken using EPA's proposed Toxicity Characteristic Leaching Procedure (TCLP) and were analyzed for a subset of organics and metals. Samples from central pits and central treatment facilities were analyzed for 136 chlorinated dioxins and furans and 79 pesticides and herbicides (USEPA 1987).

API Analytical Methods

API analyzed for 125 organics, 29 metals, 15 conventional contaminants, and 2 RCRA characteristics for each sample. The same methods were used by API and EPA for analysis of metals and conventional pollutants with some minor variations. For organics analysis EPA used methods 1624C and 1625C, while API used EPA methods 624 and 625. While the two method types are comparable, method 1624 (and 1625C) may give a more accurate result because of less interference from the matrix and a lower detection limit than methods 624 and 625. In addition, QA/QC on API's program has not been verified by EPA. See USEPA 1987 for a discussion of EPA analytical methods.

Results

Chemical Constituents Found by EPA in Oil and Gas Extraction Waste Streams

As previously stated, EPA collected a total of 101 samples from drilling sites, production sites, waste treatment facilities, and commercial waste storage and disposal facilities. Of these 101 samples, 42 were sludge samples and 59 were liquid samples (USEPA 1987).

Health-based numbers in milligrams per liter (mg/L) were tabulated for all constituents for which there are Agency-verified limits. These are either reference doses for noncarcinogens (Rfds) or risk-specific doses (RSDs) for carcinogens. RSDs were calculated, using the following risk levels: 10-6 for class A (human carcinogen) and 10-5 for class B (probable human carcinogen). Maximum contaminant limits (MCLs) were used, when available, then Rfds or RSDs. An MCL is an enforceable drinking water standard that is used by the Office of Solid Waste when ground water is a main exposure pathway.

Two multiples of the health-based limits (or MCLs) were calculated for comparison with the sample levels found in the wastes. Multiples of 100 were used to approximate the regulatory level set by the EP toxicity test (i.e., 100 x the drinking water standards for some metals and pesticides). Multiples of 1,000 were used to approximate the concentration of a leachate which, as a first screen, is a threshold level of potential regulatory concern. Comparison of constituent levels found by direct analysis of waste with multiples of health-based numbers (or MCLs) can be used to approximate dispersion of this waste to surface waters. Comparison of constituent levels found by TCLP analysis of waste with multiples of health-based numbers (or MCLs) can be used to approximate dispersion of this waste to ground water.

For those polyaromatic hydrocarbons (PAHs) for which verified health-based numbers do not exist, limits were estimated by analogy with known toxicities of other PAHs. If structure activity analysis (SAR) indicated that the PAH had the potential to be carcinogenic, then it was assigned the same health-based number as benzo(a)pyrene, a potent carcinogen. If the SAR analysis yielded equivocal results, the PAH was assigned the limit given to indeno-(1,2,3-cd) pyrene, a PAH with possible carcinogenic potential. If the SAR indicated that the PAH was not likely to be carcinogenic, then it was assigned the same number as naphthalene, a noncarcinogen.

The analysis in this chapter does not account for the frequency of detection of constituents, or nonhuman health effects. Therefore, it provides a useful indication of the constituents deserving further study, but may not provide an accurate description of the constituents that have the potential to pose actual human health and environmental risks. Readers should refer to Chapter V, "Risk Modeling," for information on human health and environmental risks and should not draw any conclusions from the analysis presented in Chapter II about the level of risk posed by wastes from oil and gas wells.

EPA may further evaluate constituents that exceeded the health-based limit or MCL multiples to determine fate, transport, persistence, and toxicity in the environment. This evaluation may show that constituents designated as secondary in the following discussion may not, in fact, be of concern to EPA.

Although the Toxicity Characteristics Leaching Procedure (TCLP) was performed on the sludge samples, the only constituent in the leach exhibiting concentrations that exceeded the multiples previously described was benzene in production tank bottom sludge. All of the other chemical constituents that exceeded the multiples were from direct analysis of the waste.

Constituents Present at Levels of Potential Concern

Because of the limited number of samples in relation to the large universe of facilities from which the samples were drawn, results of the waste sampling program conducted for this study must be analyzed carefully. EPA is conducting a statistical analysis of these samples.

Table II-4 shows EPA and API chemical constituents that were present in oil and gas extraction waste streams in amounts greater than health-based limits multiplied by 1,000 (primary concern) and those constituents that occurred within the range of multiples of 100 and 1,000 (secondary concern). Benzene and arsenic, constituents of primary and secondary concern respectively, by this definition, were modeled in the risk assessment chapter (Chapter V). The table compares waste stream location and sample phase with the constituents found at that location and phase. Table II-5 shows the number of samples compared with the number of detects in EPA samples for each constituent of potential concern.

The list of constituents of potential concern is not final. EPA is currently evaluating the data collected at the central treatment facilities and central pits, and more chemical constituents of potential concern may result from this evaluation. Also, statistical analysis of the sampling data is continuing.

Table II-4 Constituents of Concern Found in Waste Streams Sampled by EPA and API

	Production			Central treatment			Central pit	Drilling		
	Midpoint	Tank bottom	Endpoint	Influent	Tank	Effluent	Central pit	Drilling mud	Tank bottoms	Pit
Chemical Constituents **Primary concern**										
Benzene	L #	S# S+	L L#•		S#	L S	S#		S#	S S•
Phenanthrene		S #	L L#•		S#		S #	S	S #	
Lead				S#		S#	S#		L#	L# L• S# S#•
Barium			L	S#	S#	S#	S#	S#	L	L# L#• S# S#•
Secondary concern										
Arsenic		S	L			S	S			S S•
Fluoride				S		S	S			L S
Antimony			L•							

Legend:
- L: Liquid sample > 100 x health-based number
- S: Sludge sample > 100 x health-based number
- #: Denotes > 1,000 x health-based number
- L,S: EPA samples
- L•,S•: API samples
- +: TCLP extraction
- — All values determined from direct samples except as denoted by "+"

Table II-5 EPA Samples Containing Constituents of Concern

	Production			Central treatment			Central pit	Drilling		
	Midpoint	Tank bottom	Endpoint	Influent	Tank	Effluent	Central pit	Drilling mud	Tank bottoms	Pit
Primary concern										
Benzene	L5 (3)	S1 (1) +	L21 (16)		S2 (1)	L3 (2) S3 (1)	S3 (1)		S1 (1)	S18 (7)
Phenanthrene		S1 (1)	L21 (5)		S2 (2)		S3 (1)	S2 (1)	S1 (1)	
Lead				S1 (1)		S3 (3)	S3 (3)		L1 (1)	L17 (17) S21 (21)
Barium			L24 (21)	S1 (1)	S2 (1)	S3 (3)	S3 (3)	S1 (1)	L1 (1)	L17 (17) S21 (21)
Secondary concern										
Arsenic		S1 (1)	L24 (9)			S3 (3)	S3 (1)			S21 (11)
Fluoride				S1 (1)		S3 (3)	S3 (3)			L17 (17) S20 (20)

Legend:
- L: Liquid sample
- S: Sludge sample
- # (#) Number of samples (number of detects)
- \+ TCLP extract and direct extracts

Comparison to Constituents of Potential Concern Identified in the Risk Analysis

This report's risk assessment selected the chemical constituents that are most likely to dominate the human health and environmental risks associated with drilling wastes and produced water endpoints. Through this screening process, EPA selected arsenic, benzene, sodium, cadmium, chromium VI, boron, chloride, and total mobile ions as the constituents to model for risk assessment.[6]

The chemicals selected for the risk assessment modeling differ from the constituents of potential concern identified in this chapter's analysis for at least three reasons. First, the risk assessment screening accounted for constituent mobility by examining several factors in addition to solubility that affect mobility (e.g., soil/water partition coefficients) whereas, in Chapter II, constituents of potential concern were not selected on the basis of mobility in the environment. Second, certain constituents were selected for the risk assessment modeling based on their potential to cause adverse environmental effects as opposed to human health effects; the Chapter II analysis considers mostly human health effects. Third, frequency of detection was considered in selecting constituents for the risk analysis but was not considered in the Chapter II analysis.

Facility Analysis

Constituents of potential concern were chosen on the basis of exceedances in liquid samples or TCLP extract. Certain sludge samples are listed in Tables II-4 and II-5, since these samples, through direct

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[6] Mobile ions modeled in the risk assessment include chloride, sodium, potassium, calcium, magnesium, and sulfate.

chemical analysis, indicated the presence of constituents at levels exceeding the multiples previously described. One sludge sample analyzed by the TCLP method contained benzene in an amount above the level of potential concern. This sample is included in Tables II-4 and II-5. The sludge samples are shown for comparison with the liquid samples and TCLP extract and were not the basis for choice as a constituent of potential concern. Constituents found in the liquid samples or the TCLP extract in amounts greater than 100 times the health-based number are considered constituents of potential concern by EPA.

Central Treatment Facility

Benzene, the only constituent found in liquid samples at the central treatment facilities, was found in the effluent in amounts exceeding the level of potential concern.

Central Pit Facility

No constituent was found in the liquid phase in amounts exceeding the level of potential concern at central pit facilities.

Drilling Facilities

Lead and barium were found in amounts exceeding the level of potential concern in the liquid phase of the tank bottoms and the reserve pits that were sampled. Fluoride was found in amounts that exceeded 100 times the health-based number in reserve pit supernatant.

Production Facility

Benzene was present in amounts that exceeded the level of potential concern at the midpoint and the endpoint locations. Exceedances of the level of potential concern that occurred only at the endpoint location were for phenanthrene, barium, arsenic, and antimony. Benzene was present in amounts exceeding the multiple of 1,000 in the TCLP leachate of one sample.

WASTE CHARACTERIZATION ISSUES

Toxicity Characteristic Leaching Procedure (TCLP)

The TCLP was designed to model a reasonable worst-case mismanagement scenario, that of co-disposal of industrial waste with municipal refuse or other types of biodegradable organic waste in a sanitary landfill. As a generic model of mismanagement, this scenario is appropriate for nonregulated wastes because those wastes may be sent to a municipal landfill. However, most waste from oil and gas exploration and production is not disposed of in a sanitary landfill, for which the test was designed. Therefore, the test may not reflect the true hazard of the waste when it is managed by other methods. However, if these wastes were to go to a sanitary landfill, EPA believes the TCLP would be an appropriate leach test to use.

For example, the TCLP as a tool for predicting the leachability of oily wastes placed in surface impoundments may actually overestimate that leachability. One reason for this overestimation involves the fact that the measurement of volatile compounds is conducted in a sealed system during extraction. Therefore, all volatile toxicants present in the waste are assumed to be available for leaching to ground water. None of the volatiles are assumed to be lost from the waste to the air. Since volatilization is a potentially significant, although as yet unquantified, route of loss from surface impoundments, the TCLP may overestimate the leaching potential of the waste. Another reason for overestimation is that the TCLP assumes that no degradation--either chemical, physical, or biological--will occur in the waste before the leachate actually leaves the impoundment. Given that leaching is not likely to begin until a finite time after disposal and will continue to occur over many years, the assumption of no change may tend to overestimate leachability.

Conversely, the TCLP may underestimate the leaching potential of petroleum wastes. One reason for this assumption is a procedural problem in the filtration step of the TCLP. The amount of mobile liquid phase that is present in these wastes and that may migrate and result in ground-water contamination is actually underestimated by the TCLP. The TCLP requires the waste to be separated into its mobile and residue solid phases by filtration. Some production wastes contain materials that may clog the filter, indicating that the waste contains little or no mobile fraction. In an actual disposal environment, however, the liquid may migrate. Thus, the TCLP may underestimate the leaching potential of these materials. Another reason for underestimation may be that the acetate extraction fluid used is not as aggressive as real world leaching fluid since other solubilizing species (e.g., detergents, solvents, humic species, chelating agents) may be present in leaching fluids in actual disposal units. The use of a citric acid extraction media for more aggressive leaching has been suggested.

Because the TCLP is a generic test that does not take site-specific factors into account, it may overestimate waste leachability in some cases and underestimate waste leachability in other cases. This is believed to be the case for wastes from oil and gas exploration and production.

The EPA has several projects underway to investigate and quantify the leaching potential of oily matrices. These include using filter aids to prevent clogging of the filter, thus increasing filtration efficiency, and using column studies to quantitatively assess the degree to which oily materials move through the soil. These projects may result in a leach test more appropriate for oily waste.

Solubility and Mobility of Constituents

Barium is usually found in drilling waste as barium sulfate (barite), which is practically insoluble in water (Considine 1974). Barium sulfate may be reduced to barium sulfide, which is water soluble. It is the relative insolubility of barium sulfate that greatly decreases its toxicity to humans; the more soluble and mobile barium sulfide is also much more toxic (Sax 1984). Barium sulfide formation from barium sulfate requires a moist anoxic environment.

The organic constituents present in the liquid samples in concentrations of potential concern were benzene and phenanthrene. Benzene was found in produced waters and effluent from central treatment facilities, and phenanthrene was found in produced waters.

An important commingling effect that can increase the mobility of nonpolar organic solvents is the addition of small amounts of a more soluble organic solvent. This effect can significantly increase the extent to which normally insoluble materials are dissolved. This solubility enhancement is a log-linear effect. A linear increase in cosolvent concentration can lead to a logarithmic increase in solubility. This effect is also additive in terms of concentration. For instance, if a number of cosolvents exist in small concentrations, their total concentration may be enough to have a significant effect on nonpolar solvents with which the cosolvents come in contact (Nkedi-Kizza 1985, Woodburn et al. 1986). Common organic cosolvents are acetone, toluene, ethanol, and xylenes (Brown and Donnelly 1986).

Other factors that must be considered when evaluating the mobility of these inorganic and organic constituents in the environment are the use of surfactants at oil and gas drilling and production sites and the general corrosivity of produced waters. Surfactants can enhance the solubility of many constituents in these waters. Produced waters have been shown to corrode casing (see damage cases in Chapter IV).

Changes in pH in the environment of disposal can cause precipitation of compounds or elements in waste and this can decrease mobility in the environment. Also adsorption of waste components to soil particles will attenuate mobility. This is especially true of soils containing clay because of the greater surface area of clay-sized particles.

Phototoxic Effect of Polycyclic Aromatic Hydrocarbons (PAH)

New studies by Kagan et al. (1984), Allred and Giesy (1985), and Bowling et al. (1983) have shown that very low concentrations (ppb in some cases) of polycyclic aromatic hydrocarbon (PAH) are lethal to some forms of aquatic wildlife when they are introduced to sunlight after exposure to the PAHs. This is called the phototoxic effect.

In the study conducted by Allred and Giesy (1985), it was shown that anthracene toxicity to Daphnia pulex resulted from activation by solar radiation of material present on or within the animals and not in the water. It appeared that activation resulted from anthracene molecules and not anthracene degeneration products. Additionally, it was shown that wavelengths in the UV-A region (315 to 380 nm) are primarily responsible for photo-induced anthracene toxicity.

It has been shown that PAHs are a typical component of some produced waters (Davani et al., 1986a). The practice of disposal of produced waters in unlined percolation pits is allowing PAHs and other constituents to migrate into and accumulate in soils (Eiceman et al., 1986a, 1986b).

pH and Other RCRA Characteristics

Of the RCRA parameters reactivity, ignitability, and corrosivity, no waste sample failed the first two. Reactivity was low and ignitability averaged 200^{o}F for all waste tested. On the average, corrosivity parameters were not exceeded, but one extreme did fail this RCRA test (See Table II-6). A solid waste is considered hazardous under RCRA if its aqueous phase has a pH less than or equal to 2 or greater than or equal to 12.5. As previously stated, a sludge sample is defined by EPA in this document as a sample containing a significant quantity of solids (normally greater than 1 percent).

Of the major waste types at oil and gas facilities, waste drilling muds and produced waters have an average neutral pH. Waste drilling fluid samples ranged from neutral values to very basic values, and produced waters ranged from neutral to acidic values. In most cases the sludge phase tends to be more basic than the liquid phases. An exception is the tank bottom waste at central treatment facilities, which has an average acidic value. Drilling waste tends to be basic in the liquid and sludge phases and failed the RCRA test for alkalinity in one extreme case. At production facilities the pH becomes more acidic from the midpoint location to the endpoint. This is probably due to the removal of hydrocarbons. This neutralizing effect of hydrocarbons is also shown by the neutral pH values of the production tank bottom waste. An interesting anomaly of Table II-6 is the alkaline values of the influent and effluent of central treatment facilities compared to the acidic values of the tank bottoms at these facilities. Because central treatment facilities accept waste drilling fluids and produced waters, acidic constituents of produced waters may be accumulating in tank bottom sludges. The relative acidity of the produced waters is also indicated by casing failures, as shown by some of the damage cases in Chapter IV.

Table II-6 pH Values for Exploration, Development and Production Wastes (EPA Samples)

	Midpoint	Tank bottom	Endpoint	Influent	Tank	Effluent	Central pit	Tank bottoms	Pit
Production									
Sludge		7.0; 7.0; 7.0							
Liquid	6.4; 6.6; 8.0		2.7; 7.6; 8.1						
Central treatment									
Sludge				8.8; 8.8; 8.8	2.0; 3.9; 5.8	6.7; 8.2; 10.0			
Liquid				5.7; 6.5; 7.3		7.0; 8.2; 10.1			
Central pit									
Sludge							7.2; 8.0; 9.2		
Liquid							5.7; 7.5; 8.5		
Drilling									
Sludge									6.8; 9.0; 12.8
Liquid								7.1; 7.1; 7.1	6.5; 7.7; 12.7

Legend:

#; #; # - minimum; average; maximum

Use of Constituents of Concern

The screening analysis conducted for the risk assessment identified arsenic, benzene, sodium, cadmium, chromium VI, boron, and chloride as the constituents that likely pose the greatest human health and environmental risks. The risk assessment's findings differ from this chapter's findings since this chapter's analysis did not consider the frequency of detection of constituents, mobility factors, or nonhuman health effects (see Table II-7). Some constituents found in Table II-4 were in waste streams causing damages as documented in Chapter IV.

Table II-7 Comparison of Potential Constituents of Concern That Were Modeled in Chapter V

Chemical	Chapter II*	Chapter V**	Reasons for not including in Chapter V risk analysis ***
Benzene	P	Yes	N/A
Phenanthrene	P	No	Low frequency in drilling pit and produced water samples; low ground-water mobility; relatively low concentration-to-toxicity ratio; unverified reference dose used for Chapter 2 analysis.
Lead	P	No	Low ground-water mobility.
Barium	P	No	Low ground-water mobility.
Arsenic	S	Yes	N/A
Fluoride	S	No	Relatively low concentration-to-toxicity ratio.
Antimony	S	No	Low frequency in drilling pit and produced water samples.

* P = primary concern in Chapter II; S = secondary concern in Chapter II.

** Yes = modeled in Chapter V analysis; no = not modeled in Chapter V analysis.

*** Table summarizes primary reasons only; additional secondary reasons may also exist.

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CHAPTER III

CURRENT AND ALTERNATIVE WASTE MANAGEMENT PRACTICES

INTRODUCTION

Managing wastes produced by the oil and gas industry is a large task. By the estimates gathered for this report, in 1985 over 361 million barrels of drilling muds and 20.9 billion barrels of produced water were disposed of in the 33 States that have significant exploration, development, and production activity. In that same year, there were 834,831 active oil and gas wells, of which about 70 percent (580,000 wells) were stripper operations.

The focus of this section is to review current waste management technologies employed for wastes at all phases of the exploration-development-production cycle of the onshore oil and gas industry. It is convenient to divide wastes into two broad categories. The first category includes drilling muds, wellbore cuttings, and chemical additives related to the drilling and well completion process. These wastes tend to be managed together and may be in the form of liquids, sludges, or solids. The second broad category includes all wastes associated with oil and gas production. Produced water is the major waste stream and is by far the highest volume waste associated with oil and gas production. Other production-related wastes include relatively small volumes of residual bactericides, fungicides, corrosion inhibitors, and other additives used to ensure efficient production; wastes from oil/gas/water separators and other onsite processing facilities; production tank bottoms; and scrubber bottoms.[1]

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[1] For the purpose of this chapter, all waste streams, whether exempt or nonexempt, are discussed.

In addition to looking at these two general waste categories, it is also important to view waste management in relation to the sequence of operations that occurs in the life cycle of a typical well. The chronology involves both drilling and production--the two phases mentioned above--but it also can include "post-closure" events, such as seepage of native brines into fresh ground water from improperly plugged or unplugged abandoned wells or leaching of wastes from closed reserve pits.

Section 8002(m) of RCRA requires EPA to consider both current and alternative technologies in carrying out the present study. Sharp distinctions between current and alternative technologies are difficult to make because of the wide variation in practices among States and among different types of operations. Furthermore, waste management technology in this field is fairly simple. At least for the major high-volume streams, there are no significant newly invented, field-proven technologies in the research or development stage that can be considered "innovative" or "emerging." Although practices that are routine in one location may be considered innovative or alternative elsewhere, virtually every waste management practice that exists can be considered "current" in one specific situation or another. This is because different climatological or geological settings may demand different management procedures, either for technical convenience in designing and running a facility or because environmental settings in a particular region may be unique. Depth to ground water, soil permeability, net evapotranspiration, and other site-specific factors can strongly influence the selection and design of waste management practices. Even where geographic and production variables are similar, States may impose quite different requirements on waste management, including different permitting conditions.

Long-term improvements in waste management need not rely, however, purely on increasing the use of better existing technology. The Agency does foresee the possibility of significant technical improvements in future technologies and practices. Examples include incineration and other thermal treatment processes for drilling fluids; conservation, recycling, reuse, and other waste minimization techniques; and wet air oxidation and other proven technologies that have not yet been applied to oil and gas operations.

Sources of Information

The descriptions and interpretations presented here are based on State or Federal regulatory requirements, published technical information, observations gathered onsite during the waste sampling program, and interviews with State officials and private industry. Emphasis is placed on practices in 13 States that represent a cross-section of the petroleum extraction industry based on their current drilling activity, rank in production, and geographic distribution. (See Table III-1.)

Limitations

Data on the prevalence, environmental effectiveness, and enforcement of waste management requirements currently in effect in the petroleum-producing States are difficult to obtain. Published data are scarce and often outdated. Some of the State regulatory agencies that were interviewed for this study have only very limited statistical information on the volumes of wastes generated and on the relative use of the various methods of waste disposal within their jurisdiction. Time was not available to gather statistics from other States that have significant oil and gas activity. This lack of concrete data makes it difficult for EPA to complete a definitive assessment of available disposal options. EPA is collecting additional data on these topics.

Table III-1 States with Major Oil Production Used as Primary References in This Study

Alaska
Arkansas
California
Colorado
Kansas
Louisiana
Michigan
New Mexico
Ohio
Oklahoma
Texas
West Virginia
Wyoming

DRILLING-RELATED WASTES

Description of Waste

Drilling wastes include a wide variety of materials, ranging in volume from the thousands of barrels of fluids ("muds") used to drill a well, to the hundreds of barrels of drill cuttings extracted from the borehole, to much smaller quantities of wastes associated with various additives and chemicals sometimes used to condition drilling fluids. A general description of each of these materials is presented in broad terms below.

Drilling Fluids (Muds)

The largest volume drilling-related wastes generated are the spent drilling fluids or muds. The composition of modern drilling fluids or muds can be quite complex and can vary widely, not only from one geographical area to another but also from one depth to another in a particular well as it is drilled.

Muds fall into two general categories: water-based muds, which can be made with fresh or saline water and are used for most types of drilling, and oil-based muds, which can be used when water-sensitive formations are drilled, when high temperatures are encountered, or when it is necessary to protect against severe drill string corrosion in hostile downhole environments. Drilling muds contain four essential parts: (1) liquids, either water or oil; (2) reactive solids, the viscosity- and density-building part of the system, often bentonite clays; (3) inert solids such as barite; and (4) additives to control the chemical, physical, and biological properties of the mud. These basic components perform various functions. For example, clays increase viscosity and density, barium sulfate (barite) acts as a weighting agent to maintain pressure in the well, and lime and caustic soda increase pH and control viscosity. Additional conditioning materials include polymers, starches, lignitic material, and various other chemicals (Canter et al. 1984).

Table III-2 presents a partial list, by use category, of additives to drilling muds (Note: this table is based on data that may, in some cases, be outdated.)

Cuttings

Well cuttings include all solid materials produced from the geologic formations encountered during the drilling process that must be managed as part of the content of the waste drilling mud. Drill cuttings consist of rock fragments and other heavy materials that settle out by gravity in the reserve pit. Other materials, such as sodium chloride, are soluble in fresh water and can pose problems in waste disposal. Naturally occurring arsenic may also be encountered in significant concentrations in certain wells and in certain parts of the country and must be disposed of appropriately. (Written communication with Mr. Don Basko, Wyoming Oil and Gas Conservation Commission.)

Waste Chemicals

In the course of drilling operations, chemicals may be disposed of by placing them in the well's reserve pit. These can include any substances deliberately added to the drilling mud for the various purposes mentioned above (see Table III-2).

Table III-2 Characterization of Oil

and Gas Drilling Fluids

Source: Information in this table was taken from American Petroleum Institute (API) Bulletin 13F (1978). Drilling practices have evolved significantly in some respects since its publication; the information presented below may therefore not be fully accurate or current.

Bases

Bases used in formulating drilling fluid are predominantly fresh water, with minor use of saltwater or oils, including diesel and mineral oils. It is estimated that the industry used 30,000 tons of diesel oil per year in drilling fluid in 1978.[a]

Weighting Agents

Common weighting agents found in drilling fluids are barite, calcium carbonate, and galena (PbS).[b] Approximately 1,900,000 tons of barite, 2,500 tons of calcium carbonate, and 50 tons of galena (the mineral form of lead) are used in drilling each year.

Viscosifiers

Viscosifiers found in drilling fluid include:

• Bentonite clays	650,000 tons/year
• Attapulgite/sepiolite	85,000 tons/year
• Asphalt/gilsonite	10,000 tons/year
• Asbestos	10,000 tons/year
• Bio-polymers	500 tons/year

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[a] This figure included contributions from offshore operations. According to API, use of diesel oil in drilling fluid has been substantially reduced in the past 10 years principally as a result of its restricted use in offshore operations.

[b] API states that galena is no longer used in drilling mud.

Table III-2 (continued)

Dispersants

Dispersants used in drilling fluid include:

• Cadmium, chromium, iron, and other metal lignosulfonates	65,000 tons/year
• Natural, causticized chromium and zinc lignite	50,000 tons/year
• Inorganic phosphates	1,500 tons/year
• Modified tannins	1,200 tons/year

Fluid Loss Reducers

Fluid loss reducers used in drilling fluid include:

• Starch/organic polymers	15,000 tons/year
• Cellulosic polymers (CMC, HEC)	12,500 tons/year
• Guar gum	100 tons/year
• Acrylic polymers	2,500 tons/year

Lost Circulation Materials

Lost circulation materials used comprise a variety of nontoxic substances including cellophane, cotton seed, rice hulls, ground Formica, ground leather, ground paper, ground pecan and walnut shells, mica, and wood and cane fibers. A total of 20,000 tons of tnese materials is used per year.

Table III-2 (continued)

Surface Active Agents

Surface active agents (used as emulsifiers, detergents, defoamants) include:

- Fatty acids, naphthenic acids, and soaps 5,000 tons/year
- Organic sulfates/sulfonates 1,000 tons/year
- Aluminum stearate (quantity not available)

Lubricants

Lubricants used include:

- Vegetable oils 500 tons/year
- Graphite <5 tons/year

Flocculating Agents

The primary flocculating agents used in drilling are:

- Acrylic polymers 2,500 tons/year

Biocides

Biocides used in drilling include:

- Organic amines, amides, amine salts 1,000 tons/year
- Aldehydes (paraformaldehyde) 500 tons/year
- Chlorinated phenols <1 ton/year
- Organosulfur compounds and organometallics (quantity not available)

Miscellaneous

Miscellaneous drilling fluid additives include:

- Ethoxylated alkyl phenols 1,800 tons/year
- Aaliphatic alcohols <10 tons/year
- Aluminum anhydride derivatives and chrom alum (quantities not available)

Table III-2 (continued)

Commercial Chemicals

Commercial chemicals used in drilling fluid include:

• Sodium hydroxide	50,000 tons/year
• Sodium chloride	50,000 tons/year
• Sodium carbonate	20,000 tons/year
• Calcium chloride	12,500 tons/year
• Calcium hydroxide/calcium oxide	10,000 tons/year
• Potassium chloride	5000 tons/year
• Sodium chromate/dichromate[a]	4,000 tons/year
• Calcium sulfate	500 tons/year
• Potassium hydroxide	500 tons/year
• Sodium bicarbonate	500 tons/year
• Sodium sulfite	50 tons/year
• Magnesium oxide	<10 tons/year
• Barium carbonate	(quantity not available)

These commercial chemicals are used for a variety of purposes including pH control, corrosion inhibition, increasing fluid phase density, treating out calcium sulfate in low pH muds, treating out calcium sulfate in high pH muds.

Corrosion Inhibitors

Corrosion inhibitors used include:

• Iron oxide	100 tons/year
• Ammonium bisulfite	100 tons/year
• Basic zinc carbonate	100 tons/year
• Zinc chromate	<10 tons/year

[a] API states that sodium chromate is no longer used in drilling mud.

Fracturing and Acidizing Fluids

Fracturing and acidizing are processes commonly used to enlarge existing channels and open new ones to a wellbore for several purposes:

- To increase permeability of the production formation of a well;
- To increase the zone of influence of injected fluids used in enhanced recovery operations; and
- To increase the rate of injection of produced water and industrial waste material into disposal wells.

The process of "fracturing" involves breaking down the formation, often through the application of hydraulic pressure, followed by pumping mixtures of gelled carrying fluid and sand into the induced fractures to hold open the fissures in the rocks after the hydraulic pressure is released. Fracturing fluids can be oil-based or water-based. Additives are used to reduce the leak-off rate, to increase the amount of propping agent carried by the fluid, and to reduce pumping friction. Such additives may include corrosion inhibitors, surfactants, sequestering agents, and suspending agents. The volume of fracturing fluids used to stimulate a well can be significant.[2] Closed systems, which do not involve reserve pits, are used very occasionally (see discussion below). However, closed systems are widely used in California. Many oil and gas fields currently being developed contain low-permeability reservoirs that may require hydraulic fracturing for commercial production of oil or gas.

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[2] Mobile Oil Co. recently set a well stimulation record (single stage) in a Wilcox formation well in Zapata County, Texas, by placing 6.3 million pounds of sand, using a fracturing fluid volume of 1.54 million gallons (World Oil, January 1987).

The process of "acidizing" is done by injecting acid into the target formation. The acid dissolves the rock, creating new channels to the wellbore and enhancing existing ones. The two basic types of acidizing treatments used are:

- Low-pressure acidizing: acidizing that avoids fracturing the formation and allows acid to work through the natural pores (matrix) of the formation.
- Acid fracturing: acidizing that utilizes high pressure and high volumes of fluids (acids) to fracture rock and to dissolve the matrix in the target formation.

The types of acids normally used include hydrochloric acid (in concentrations ranging from 15 to 28 percent in water), hydrochloric-hydrofluoric acid mixtures (12 percent and 3 percent, respectively), and acetic acid. Factors influencing the selection of acid type include formation solubility, reaction time, reaction products effects, and the sludging and emulsion-forming properties of the crude oil. The products of spent acid are primarily carbon dioxide and water.

Spent fracturing and acidizing fluid may be discharged to a tank, to the reserve pit, or to a workover pit.

Completion and Workover Fluids

Completion and workover fluids are the fluids placed in the wellbore during completion or workover to control the flow of native formation fluids, such as water, oil, or gas. The base for these fluids is usually water. Various additives are used to control density, viscosity, and filtration rates; prevent gelling of the fluid; and reduce corrosion. They include a variety of salts, organic polymers, and corrosion inhibitors.

When the completion or workover operation is completed, the fluids in the wellbore are discharged into a tank, the reserve pit, or a workover pit.

Rigwash and Other Miscellaneous Wastes

Rigwash materials are compounds used to clean decks and other rig equipment. They are mostly detergents but can include some organic solvents, such as degreasers.

Other miscellaneous wastes include pipe dope used to lubricate connections in pipes, sanitary sewage, trash, spilled diesel oil, and lubricating oil.

All of these materials may, in many operations, be disposed of in the reserve pit.

ONSITE DRILLING WASTE MANAGEMENT METHODS

Several waste management methods can be used to manage oil and gas drilling wastes onsite. The material presented below provides a separate discussion for reserve pits, landspreading, annular disposal, solidification of reserve pit wastes, treatment and disposal of liquid wastes to surface water, and closed treatment systems.

Several waste management methods may be employed at a particular site simultaneously. Issues associated with reserve pits are particularly complex because reserve pits are both an essential element of the drilling process and a method for accumulating, storing, and disposing of wastes. This section therefore begins with a general discussion of several aspects of reserve pits--design, construction, operation, and closure--and then continues with more specific discussions of the other technologies used to manage drilling wastes.

Reserve Pits

Description

Reserve pits, an essential design component in the great majority of well drilling operations,[3] are used to accumulate, store, and, to a large extent, dispose of spent drilling fluids, cuttings, and associated drill site wastes generated during drilling, completion, and testing operations.

There is generally one reserve pit per well. In 1985, an estimated 70,000 reserve pits were constructed. In the past, reserve pits were used both to remove and dispose of drilled solids and cuttings and to store the active mud system prior to its being recycled to the well being drilled. As more advanced solids control and drilling fluid technology has become available, mud tanks have begun to replace the reserve pit as the storage and processing area for the active mud system, with the reserve pit being used to dispose of waste mud and cuttings. Reserve pits will, however, continue to be the principal method of drilling fluid storage and management.

A reserve pit is typically excavated directly adjacent to the site of the rig and associated drilling equipment. Pits should be excavated from undisturbed, stable subsoil so as to avoid pit wall failure. Where it is impossible to excavate below ground level, the pit berm (wall) is usually constructed as an earthen dam that prevents runoff of liquid into adjacent areas.

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[3] Closed systems, which do not involve reserve pits, are used very occasionally (see discussion below). However, closed systems are widely used in California.

In addition to the components found in drilling mud, common constituents found in reserve pits include salts, oil and grease, and dissolved and/or suspended heavy metals. Sources of soluble salt contamination include formation waters, downhole salt layers, and drilling fluid additives. Sources of organic contamination include lubricating oil from equipment leaks, well pressure control equipment testing, heavy oil-based lubricants used to free stuck drill pipe, and, in some cases, oil-based muds used to drill and complete the target formation.[4] Sources of potential heavy metal contamination include drilling fluid additives, drilled solids, weighting materials, pipe dope, and spilled chemicals (Rafferty 1985).

The reserve pit itself can be used for final disposal of all or part of the drilling wastes, with or without prior onsite treatment of wastes, or for temporary storage prior to offsite disposal. Reserve pits are most often used in combination with some other disposal techniques, the selection of which depends on waste type, geographical location of the site, climate, regulatory requirements, and (if appropriate) lease agreements with the landowner.

The major onsite waste disposal methods include:

- Evaporation of supernatant;
- Backfilling of the pit itself, burying the pit solids and drilled cuttings by using the pit walls as a source of material (the most common technique);
- Landspreading all or part of the pit contents onto the area immediately adjacent to the pit;

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[4] Charles A. Koch of the North Dakota Industrial Commission, Oil and Gas Division, states that "A company would not normally change the entire drilling fluid for just the target zone. This change would add drastically to the cost of drilling."

- Onsite treatment and discharge;
- Injecting or pumping all or part of the wastes into the well annulus; and
- Discharge to surface waters.

Another less common onsite management method is chemical solidification of the wastes.

Dewatering and burial of reserve pit contents (or, alternatively, landspreading the pit contents) are discussed here because they are usually an integral aspect of the design and operation of a reserve pit. The other techniques are discussed separately.

Dewatering of reserve pit wastes is usually accomplished through natural evaporation or skimming of pit liquids. Evaporation is used where climate permits. The benefits of evaporation may be overstated. In the arid climate of Utah, 93 percent of produced waters in an unlined pit percolated into the surrounding soil. Only 7 percent of the produced water evaporated (Davani et al. 1985). Alternatively, dewatering can be accomplished in areas of net precipitation by siphoning or pumping off free liquids. This is followed by disposal of the liquids by subsurface injection or by trucking them offsite to a disposal facility. Backfilling consists of burying the residual pit contents by pushing in the berms or pit walls, followed by compaction and leveling. Landspreading can involve spreading the excess muds that are squeezed out during the burial operation on surrounding soils; where waste quantities are large, landowners' permission is generally sought to disperse this material on land adjacent to the site. (This operation is different from commercial landfarming, which is discussed later.)

Environmental Performance

Construction of reserve pits is technically simple and straightforward. They do not require intensive maintenance to ensure proper function, but they may, in certain circumstances, pose environmental hazards during their operational phase.

Pits are generally built or excavated into the surface soil zones or into unconsolidated sediments, both of which are commonly highly permeable. The pits are generally unlined,[5] and, as a result, seepage of liquid and dissolved solids may occur through the pit sides and bottom into any shallow, unconfined freshwater aquifers that may be present. When pits are lined, materials used include plastic liners, compacted soil, or clay. Because reserve pits are used for temporary storage of drilling mud, any seepage of pit contents to ground water may be temporary, but it can in some cases be significant, continuing for decades (USEPA 1986).

Other routes of environmental exposure associated with reserve pits include rupture of pit berms and overflow of pit contents, with consequent discharge to land or surface water. This can happen in areas of high rainfall or where soil used for berm construction is particularly unconsolidated. In such situations, berms can become saturated and weakened, increasing the potential for failure. Leaching of pollutants after pit closure can also occur and may be a long-term problem especially in areas with highly permeable soils.

[5] An API study suggests that 37 percent of reserve pits are lined with a clay or synthetic liner.

Annular Disposal of Pumpable Drilling Wastes

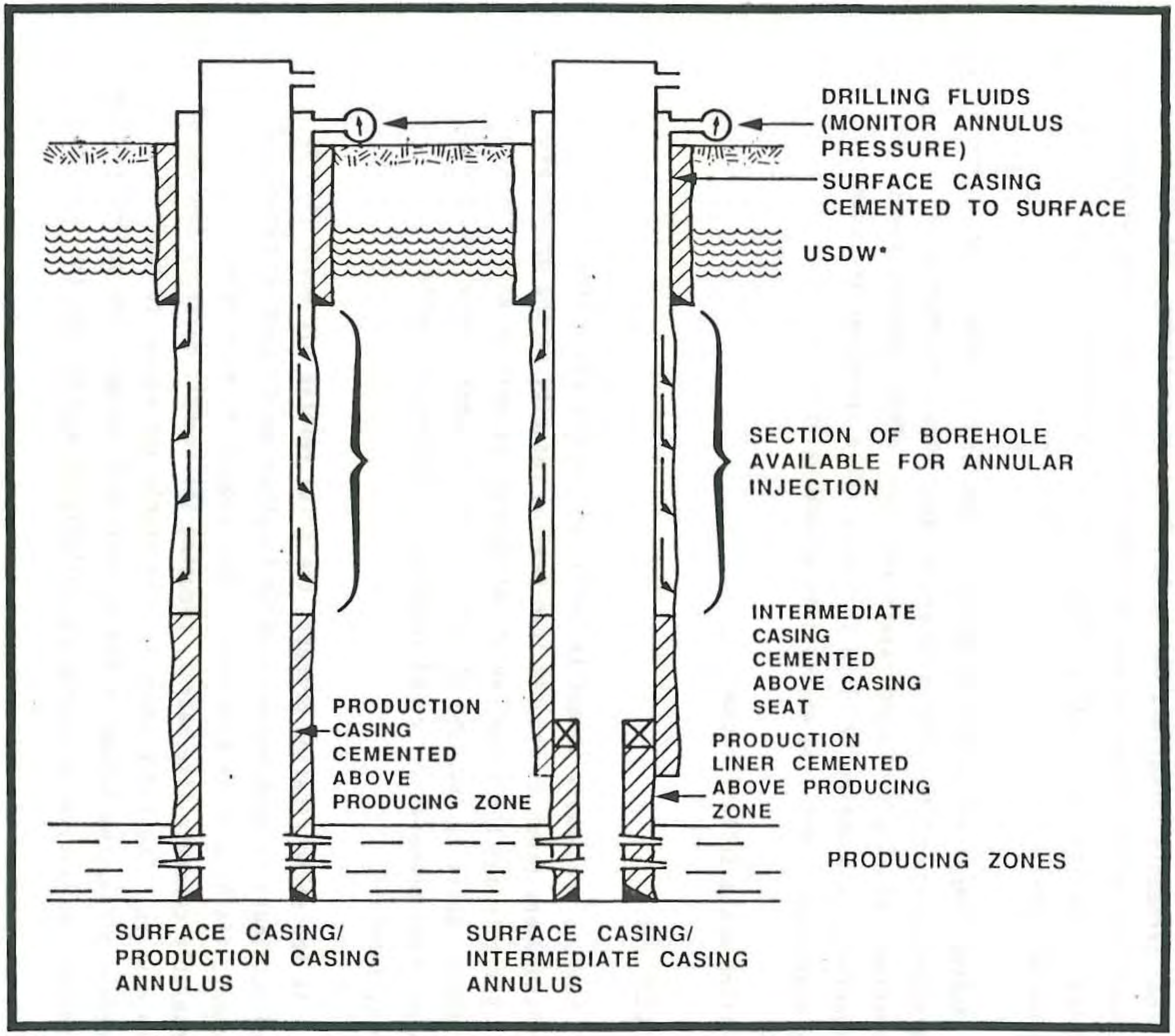
Description

Annular disposal involves the pumping of waste drilling fluids down the annulus created between the surface and intermediate casing of a well (see Figure III-1). (Disposal of solids is accomplished by using burial, solidification, landfarming, or landspreading techniques.) Disposal down the surface casing in the absence of an intermediate casing is also considered annular disposal. Annular disposal of pumpable drilling wastes is significantly more costly than evaporation, dewatering, or land application and is generally used when the waste drilling fluid contains an objectionable level of a contaminant or contaminants (such as chlorides, metals, oil and grease, or acid) which, in turn, limits availability of conventional dewatering or land application of drilling wastes. However, for disposal in a "dry" hole, costs may be relatively low. No statistics are available on how frequently annular injection of drilling wastes is used.

Environmental Performance

The well's surface casing is intended to protect fresh ground-water zones during drilling and after annular injection. To avoid adverse impacts on ground water in the vicinity of the well after annular injection, it is important that surface casing be sound and properly cemented in place. There is no feasible way to test the surface casing for integrity without incurring significant expense.

Assuming the annulus is open and the surface casing has integrity, the critical implementation factor is the pressure at which the reserve



* UNDERGROUND SOURCE OF DRINKING WATER
NOTE: NOT TO SCALE

Figure III-1 Annular Disposal of Waste Drilling Fluids pit contents are injected. The receiving strata are usually relatively shallow, permeable formations having low fracture pressures. If these pressures are exceeded during annular injection, the strata may develop vertical fractures, potentially allowing migration of drilling waste into freshwater zones.

Another important aspect of annular injection is identification and characterization of the confining shale layer above the receiving formation. Shallow confining layers are, very often, discontinuous. Any unidentified discontinuity close to the borehole increases the potential for migration of drilling wastes into ground water.

Drilling Waste Solidification

Description

Surface problems with onsite burial of reserve pit contents reported by landowners (such as reduced load-bearing capacity of the ground over the pit site and the formation of wet spots), as well as environmental problems caused by leaching of salts and toxic constituents into ground water, have prompted increased interest in reserve pit waste solidification.

In the solidification process, the total reserve pit waste (fluids and cuttings) is combined with solidification agents such as commercial cement, flash, or lime kiln dust. This process forms a relatively insoluble concrete-like matrix, reducing the overall moisture content of the mixture. The end product is more stable and easier to handle than reserve pit wastes buried in the conventional manner.. The solidification process can involve injecting the solidifying agents into the reserve pit or pumping the wastes into a mixing chamber near the pit. The waste does not have to be dewatered prior to treatment. Solidification can increase the weight and bulk of the treated waste, which may in some cases be a disadvantage of this method.

Environmental Performance

Solidification of reserve pit wastes offers a variety of environmental improvements over simple burial of wastes, with or without dewatering. By reducing the mobility of potentially hazardous materials, such as heavy metals, the process decreases the potential for contamination of ground water from leachate of unsolidified, buried reserve pit wastes. Bottom sludges, in which heavy metals largely accumulate, may continue to leach into ground water. (There are no data to establish whether the use of kiln dust would add harmful constituents to reserve pit waste. Addition of kiln dust would increase the volume of waste to be managed.)

Treatment and Discharge of Liquid Wastes to Land or Surface Water

Description

Discharge of waste drilling fluid to surface water is prohibited by EPA's zero discharge effluent guideline. However, in the Gulf Coast area, the liquid phase of waste drilling muds having low chloride concentrations is chemically treated for discharge to surface water. The treated aqueous phase (at an appropriate alkaline pH) can then be discharged to land or surface water bodies.[6] The addition of selected reagents to reserve pit liquids must achieve the necessary reactions to allow effective separation of the suspended solids prior to dewatering of the sludge in the reserve pit.

Onsite treatment methods used prior to discharge are commercially available for reserve pit fluids as well as for solids. They are typically provided by mobile equipment brought to the drill site. These methods include pH adjustment, aeration, coagulation and flocculation, centrifugation, filtration, dissolved gas flotation, and reverse osmosis. All these methods, however, are more expensive than the more common approach of dewatering through evaporation and percolation. Usually, a treatment company employs a combination of these methods to treat the sludge and aqueous phases of reserve pit wastes.

Environmental Performance

Treatment and discharge of liquid wastes are used primarily to shorten the time necessary to close a pit.

Closed Cycle Systems

Description

A closed cycle waste treatment system can be an alternative to the use of a reserve pit for onsite management and disposal of drilling

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6 David Flannery states that his interpretation of EPA's effluent guidelines would preclude such a discharge. "On July 4, 1987, a petition was filed with EPA to revise the effluent guideline. If that petition is granted, stream discharges of drilling fluid and produced fluids would be allowed at least from operations in the Appalachian States."

wastes. Essentially an adaptation of offshore systems for onshore use, closed systems have come into use relatively recently. Because of their high cost, they are used very rarely, usually only when operations are located at extremely delicate sites (such as a highly sensitive wildlife area), in special development areas (such as in the center of an urbanized area), or where the cost of land reclamation is considered excessive. They can also be used where limited availability of makeup water for drilling fluid makes control of drill cuttings by dilution infeasible.

Closed cycle systems are defined as systems in which mechanical solids control equipment (shakers, impact type sediment separation, mud cleaners, centrifuges, etc.) and collection equipment (roll-off boxes, vacuum trucks, barges, etc.) are used to minimize waste mud and cutting volumes to be disposed of onsite or offsite. This in turn maximizes the volume of drilling fluid returned to the active mud system. Benefits derived from the use of this equipment include the following (Hanson et al. 1986):

- A reduction in the amount of water or oil needed for mud maintenance;
- An increased rate of drill bit penetration because of better solids control;
- Lower mud maintenance costs;
- Reduced waste volumes to be disposed of; and
- Reduction in reserve pit size or total elimination of the reserve pit.

Closed cycle systems range from very complex to fairly simple. The degree of solids control used is based on the mud type and/or drilling program and the economics of waste transportation to offsite disposal facilities (particularly the dollars per barrel charges at these facilities versus the cost per day for additional solids control equipment rental). Closed systems at drill sites can be operated to have recirculation of the liquid phase, the solid phase, or both. In reality, there is no completely closed system for solids because drill cuttings are always produced and removed. The closed system for solids, or the mud recirculation system, can vary in design from site to site, but the system must have sufficient solids handling equipment to effectively remove the cuttings from muds to be reused.

Water removed from the mud and cuttings can be reused. It is possible to operate a separate closed system for water reuse onsite along with the mud recirculation system. As with mud recirculation systems, the design of a water recirculation system can vary from site to site, depending on the quality of water required for further use. This may include chemical treatment of the water.

Environmental Performance

Although closed systems offer many environmental advantages, their high cost seriously reduces their potential use, and the mud and cuttings must still ultimately be disposed of.

Disposal of Drilling Wastes on the North Slope of Alaska--A Special Case

The North Slope is an arctic desert consisting of a wet coastal plain underlain by up to 2,500 feet of permafrost, the upper foot or two of which thaws for about 2 months a year. The North Slope is considered to be a sensitive area because of the extremely short growing season of the tundra, the short food chain, and the lack of species diversity found in this area. Because of the area's severe climate, field practices for management of drilling media and resulting waste are different on the North Slope of Alaska from those found elsewhere in the country. In the Arctic, production pads are constructed above ground using gravel. This type of construction prevents melting of the permafrost. Reserve pits are constructed on the production pads using gravel and native soils for the pit walls; they become a permanent part of the production facility. Pits are constructed above and below grade.

Because production-related reserve pits on the North Slope are permanent, the contents of these pits must be disposed of periodically. This is done by pumping the aqueous phase of a pit onto the tundra. This pumping can take place after a pit has remained inactive for 1 year to allow for settling of solids and freeze-concentration of constituents; the aqueous phase is tested for effluent limits for various constituents established by the State of Alaska. The National Pollutant Discharge Elimination System (NPDES) permit system does not cover these discharges. An alternative to pumping of the reserve pit liquids onto the tundra is to "road-spread" the liquid, using it as a dust control agent on the gravel roads connecting the production facilities. Prior to promulgation of new State regulations, no standards other than "no oil sheen" were established for water used for dust control. ADEC now requires that at the edge of the roads, any leachate, runoff, or dust must not cause a violation of the State water quality standards. Alaska is evaluating the need for setting standards for the quality of fluids used to avoid undesirable impacts. Other North Slope disposal options for reserve pit liquids include disposal of the reserve pit liquids through annular injection or disposal in Class II wells. The majority of reserve pit liquids are disposed of through discharge to the tundra.

Reserve pits on the North Slope are closed by dewatering the pit and filling it with gravel. The solids are frozen in place above grade and below grade. Freezing in place of solid waste is successful as long as hydrocarbon contamination of the pit contents is minimized. Hydrocarbon residue in the pit contents can prevent the solids from freezing completely. In above-grade structures thawing will occur in the brief summer. If the final waste surface is below the active thaw zone, the wastes will remain frozen year-round.

Disposal of produced waters on the North Slope is through subsurface injection. This practice does not vary significantly from subsurface injection of production wastes in the Lower 48 States, and a description of this practice can be found under "Production-Related Wastes" below.

Environmental Performance

Management of drilling media and associated waste can be problematic in the Arctic. Because of the severe climate, the reserve pits experience intense freeze-thaw cycles that can break down the stability of the pit walls, making them vulnerable to erosion. From time to time, reserve pits on the North Slope have breached, spilling untreated liquid and solid waste onto the surrounding tundra. Seepage of untreated reserve pit fluids through pit walls is also known to occur.

Controlled discharge of excess pit liquids is a State-approved practice on the North Slope; however, the long-term effects of discharging large quantities of liquid reserve pit waste on this sensitive environment are of concern to EPA, Alaska Department of Environmental Conservation (ADEC), and officials from other Federal agencies. The existing body of scientific evidence is insufficient to conclusively demonstrate whether or not there are impacts resulting from this practice.

OFFSITE WASTE MANAGEMENT METHODS

Offsite waste management methods include the use of centralized disposal pits (centralized injection facilities, either privately or commercially operated, will be discussed under "subsurface injection" of production wastes), centralized treatment facilities, commercial landfarming, and reconditioning and reuse of drilling media.

Centralized Disposal Pits

Description

Centralized disposal pits are used in many States to store and dispose of reserve pit wastes. In some cases, large companies developing an extensive oil or gas field may operate centralized pits within the field for better environmental control and cost considerations. Most centralized pits are operated commercially, primarily for the use of smaller operators who cannot afford to construct properly designed and sited disposal pits for their own use. They serve the disposal needs for drilling or production wastes from multiple wells over a large geographical area. Centralized pits are typically used when storage and disposal of pit wastes onsite are undesirable because of the high chloride content of the wastes or because of some other factor that raises potential problems for the operators.[7] Wastes are generally transported to centralized disposal pits in vacuum trucks. These centralized pits are usually located within 25 miles of the field sites they serve.

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[7] Operators, for instance, may be required under their lease agreements with landowners not to dispose of their pit wastes onsite because of the potential for ground-water contamination.

The number of commercial centralized pits in major oil-producing States may vary from a few dozen to a few hundred. The number of privately developed centralized pits is not known.

Technically, a centralized pit is identical in basic construction to a conventional reserve pit. It is an earthen impoundment, which can be lined or unlined and used to accumulate, store, and dispose of drilling fluids from drilling operations within a certain geographical area. Centralized pits tend to be considerably larger than single-well pits; surface areas can be as large as 15 acres, with depths as great as 50 feet. Usually no treatment of the pit contents is performed. Some centralized pits are used as separation pits, allowing for solids settling. The liquid recovered from this settling process may then be injected into disposal wells. Many centralized pits also have State requirements for oil skimming and reclamation.

Environmental Performance

Centralized pits are a storage and disposal operation; they usually perform no treatment of wastes.

Closure of centralized pits may pose adverse environmental impacts. In the past some pits have been abandoned without proper closure, sometimes because of the bankruptcy of the original operator. So far as EPA has been able to determine, only one State, Louisiana, has taken steps to avoid this eventuality; Louisiana requires operators to post a bond or irrevocable letter of credit (based on closing costs estimated in the facility plan) and have at least $1 million of liability insurance to cover operations of open pits.

Centralized Treatment Facilities

Description

A centralized treatment facility for oil and gas drilling wastes is a process facility that accepts such wastes solely for the purpose of conditioning and treating wastes to allow for discharge or final disposal. Such facilities are distinct from centralized disposal pits, which do not treat drilling wastes as part of their storage and disposal functions. The use of such facilities may remove the burden of disposal of wastes from the operators in situations where State regulations have imposed stringent disposal requirements for burying reserve pit wastes onsite.

Centralized treatment may be an economically viable alternative to onsite waste disposal for special drilling fluids, such as oil-based muds, which cannot be disposed of in a more conventional manner. The removal, hauling, and treatment costs incurred by treatment at commercial sites will generally outweigh landspreading or onsite burial costs. A treatment facility can have a design capacity large enough to accept a great quantity of wastes from many drilling and/or production facilities.

Many different treatment technologies can potentially be applied to centralized treatment of oil and gas drilling wastes. The actual method used at the particular facility would depend on a number of factors. One of these factors is type of waste. Currently, some facilities are designed to treat solids for pH adjustment, dewatering, and solidification (muds and cuttings), while others are designed to treat produced waters, completion fluids, and stimulation fluids. Some facilities can treat a combination of wastes. Other factors determining treatment method include facility capacity, discharge options and requirements, solid waste disposal options, and other relevant State or local requirements.

Environmental Performance

Experience with centralized treatment is limited. Until recently, it was used only for treatment of offshore wastes. Its use in recent years for onshore wastes is commercially speculative, being principally a commercial response to the anticipated impacts of stricter State rules pertaining to oil and gas drilling and production waste. The operations have not been particularly successful as business ventures so far.

Commercial Landfarming

Description

Landfarming is a method for converting reserve pit waste material into soil-like material by bacteriological breakdown and through soil incorporation. The method can also be used to process production wastes, such as production tank bottoms, emergency pit cleanouts, and scrubber bottoms. Incorporation into soil uses dilution, biodegradation, chemical alteration, and metals adsorption mechanisms of soil and soil bacteria to reduce waste constituents to acceptable soil levels consistent with intended land use.

Solid wastes are distributed over the land surface and mixed with soils by mechanical means. Frequent turning or disking of the soil is necessary to ensure uniform biodegradation. Waste-to-soil ratios are normally about 1:4 in order to restrict concentrations of certain pollutants in the mixture, particularly chlorides and oil (Tucker 1985). Liquids can be applied to the land surface by various types of irrigation including sprinkler, flood, and ridge and furrow. Detailed landfarming design procedures are discussed in the literature (Freeman and Deuel 1984).

Landfarming methods have been applied to reserve pit wastes in commercial offsite operations. The technique provides both treatment and final disposition of salts, oil and grease, and solids. Landfarming may eventually produce large volumes of soil-like material that must be removed from the area to allow operations to continue.

Requirements for later reuse or disposal of this material must be determined separately.

Environmental Performance

Landfarming is generally done in areas large enough to incorporate the volume of waste to be treated. In commercial landfarming operations where the volume of materials treated within a given area is large, steps must be taken to ensure protection of surface and ground water. It is important, for instance, to minimize application of free liquids so as to reduce rapid transport of fluids through the soils.

The process is most suitable for the treatment of organics, especially the lighter fluid fractions that tend to distribute themselves quickly into the soil through the action of biodegradation. Heavy metals are also "treated" in the sense that they are adsorbed onto clay particles in the soil, presumably within a few feet of where they are applied; but the capacity of soils to accept metals is limited depending upon clay content. Similarly, the ability of the soil to accept chlorides and still sustain beneficial use is also limited.

Some States, such as Oklahoma and Kansas, prohibit the use of commercial landfarming of reserve pit wastes. Other States, such as Louisiana, allow reuse of certain materials treated at commercial landfarming facilities. Materials determined to meet certain criteria after treatment can be reused for applications such as daily sanitary landfill covering or roadbed construction. When reusing landfarmed material, it is important that such material not adversely affect any part of the food chain.

Reconditioning and Reuse of Drilling Media

Description

Reconditioning and reuse of drilling media are currently practiced in a few well-defined situations. The first such situation involves the reconditioning of oil-based muds. This is a universal practice because of the high cost of oil used in making up this type of drilling media. A second situation involves the reuse of reserve pit fluids as "spud" muds, the muds used in drilling the initial shallow portions of a well in which lightweight muds can be used. A third situation involves the increased reuse of drilling fluid at one well, using more efficient solids removal. Less mud is required for drilling a single well if efficient solids control is maintained. Another application for reuse of drilling media is in the plugging procedure for well abandonment. Pumpable portions of the reserve pit are transported by vacuum truck to the well being closed. The muds are placed in the wellbore to prevent contamination of possibly productive strata and freshwater aquifers from saltwater strata. The ability to reuse drilling media economically varies widely with the distance between drilling operations, frequency and continuity of the drilling schedule, and compatibility between muds and formations among drill sites.

Environmental Performance

The above discussion raises the possibility of minimization of drilling fluids as an approach to limiting any potential environmental impacts of drilling-related wastes. Experience in reconditioning and reusing spud muds and oil-based muds does not provide any estimate of specific benefits that might be associated with recycling or reuse of most conventional drilling muds. Benefits from mud recycling at the project level can be considerable. From a national perspective, benefits are unknown. The potential for at least some increased recycling and reuse appears to exist primarily through more efficient management of mud handling systems. Specific attempts to minimize the volume of muds used are discouraged, at present, by two factors: (1) drilling mud systems are operated by independent contractors, for whom sales of muds are a primary source of income, and (2) the central concern of all parties is successful drilling of the well, resulting in a general bias in favor of using virgin materials.

In spite of these economic disincentives, recent industry studies suggest that the benefits derived from decreasing the volume of drilling mud used to drill a single well are significant, resulting in mud cost reductions of as much as 30 percent (Amoco 1985).

PRODUCTION-RELATED WASTES

Waste Characterization

Produced Water

When oil and gas are extracted from hydrocarbon reservoirs, varying amounts of water often accompany the oil or gas being produced. This is known as produced water. Produced water may originate from the reservoir being produced or from waterflood treatment of the field (secondary recovery). The quantity of water produced is dependent upon the method of recovery, the nature of the formation being produced, and the length of time the field has been producing. Generally, the ratio of produced water to oil or gas increases over time as the well is produced.

Most produced water is strongly saline. Occasionally, chloride levels, and levels of other constituents, may be low enough (i.e., less than 500 ppm chlorides) to allow the water to be used for beneficial purposes such as crop irrigation or livestock watering. More often, salinity levels are considerably higher, ranging from a few thousand parts per million to over 150,000 ppm. Seawater, by contrast, is typically about 35,000 ppm chlorides. Produced water also tends to contain quantities of petroleum hydrocarbons (especially lower molecular weight compounds), higher molecular weight alkanes, polynuclear aromatic hydrocarbons, and metals. It may also contain residues of biocides and other additives used as production chemicals. These can include coagulants, corrosion inhibitors, cleaners, dispersants, emulsion breakers, paraffin control agents, reverse emulsion breakers, and scale inhibitors.

Radioactive materials, such as radium, have been found in some oil field produced waters. Ra-226 activity in filtered and unfiltered produced waters has been found to range between 16 and 395 picocuries/liter; Ra-228 activity may range from 170 to 570 picocuries/liter (USEPA 1985). The ground-water standard for the Maximum Contaminant Level (MCL) for combined Ra-226 and Ra-228 is 5 picocuries/liter (40 CFR, Part 257, Appendix 1). No study has been done to determine the percentage of produced water that contains radioactive materials.

Low-Volume Production Wastes

Low-volume production-related wastes include many of the chemical additives discussed above in relation to drilling (see Table III-2), as well as production tank bottoms and scrubber bottoms.

Onsite Management Methods

Onsite management methods for production wastes include subsurface injection, the use of evaporation and percolation pits, discharge of produced waters to surface water, and storage.

Subsurface Injection

Description: Today, subsurface injection is the primary method for disposing of produced water from onshore operations, whether for enhanced oil recovery (EOR) or for final disposal. Nationally, an estimated 80 percent of all produced water is disposed of in injection wells permitted under EPA's Underground Injection Control (UIC) program under the authority of the Safe Drinking Water Act.[8] In the major oil-producing States, it is estimated that over 90 percent of production wastes are disposed of by this method. Subsurface injection may be done at injection wells onsite, offsite, or at centralized facilities. The mechanical design and procedures are generally the same in all cases.

In enhanced recovery projects, produced water is generally reinjected into the same reservoir from which the water was initially produced. Where injection is used solely for disposal, produced water is injected into saltwater formations, the original formation, or older depleted producing formations. Certain physical criteria make a formation suitable for disposal, and other criteria make a formation acceptable to regulatory authorities for disposal.

The sequence of steps by which waste is placed in subsurface formations may include:

- Separation of free oil and grease from the produced water;
- Tank storage of the produced water;
- Filtration;
- Chemical treatment (coagulation, flocculation, and possibly pH adjustment); and, ultimately,
- Injection of the fluid either by pumps or by gravity flow.

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8 API states that 80 to 90 percent of all produced water is injected in Class II wells.

By regulation, injection for the purpose of disposal must take place below all formations containing underground sources of drinking water (USDWs). Figure III-2 displays a typical disposal well pumping into a zone located below the freshwater table (Templeton and Associates 1980). The type of well often preferred by State regulatory agencies is the well specifically drilled, cased, and completed to accept produced water and other oil and gas production wastes. Another type of disposal well is a converted production well, the more prevalent type of disposal and enhanced recovery well. An injection well's location and age and the composition of injected fluids are the important factors in determining the level of mechanical integrity and environmental protection the well can provide.

Although it is not a very widespread practice, some produced water is disposed of through the annulus of producing wells. In this method, produced water is injected through the annular space between the production casing and the production tubing (see Figure III-3).[9] Injection occurs using little or no pressure. The disposal zone is shallower than the producing zone in this case. Testing of annular disposal wells is involved and expensive.

One method of testing the mechanical integrity of the casing used for annular injection, without removing the tubing and packer, is through the use of radioactive tracers and sensing devices. This method involves the pumping of water spiked with a low-level radioactive tracer into the injection zone, followed by running a radioactivity-sensing logging tool through the tubing string. This procedure should detect any shallow casing leaks or any fluid migration between the casing and the borehole. Most State regulatory agencies discourage annular injection and allow the practice only in small-volume, low-pressure applications.

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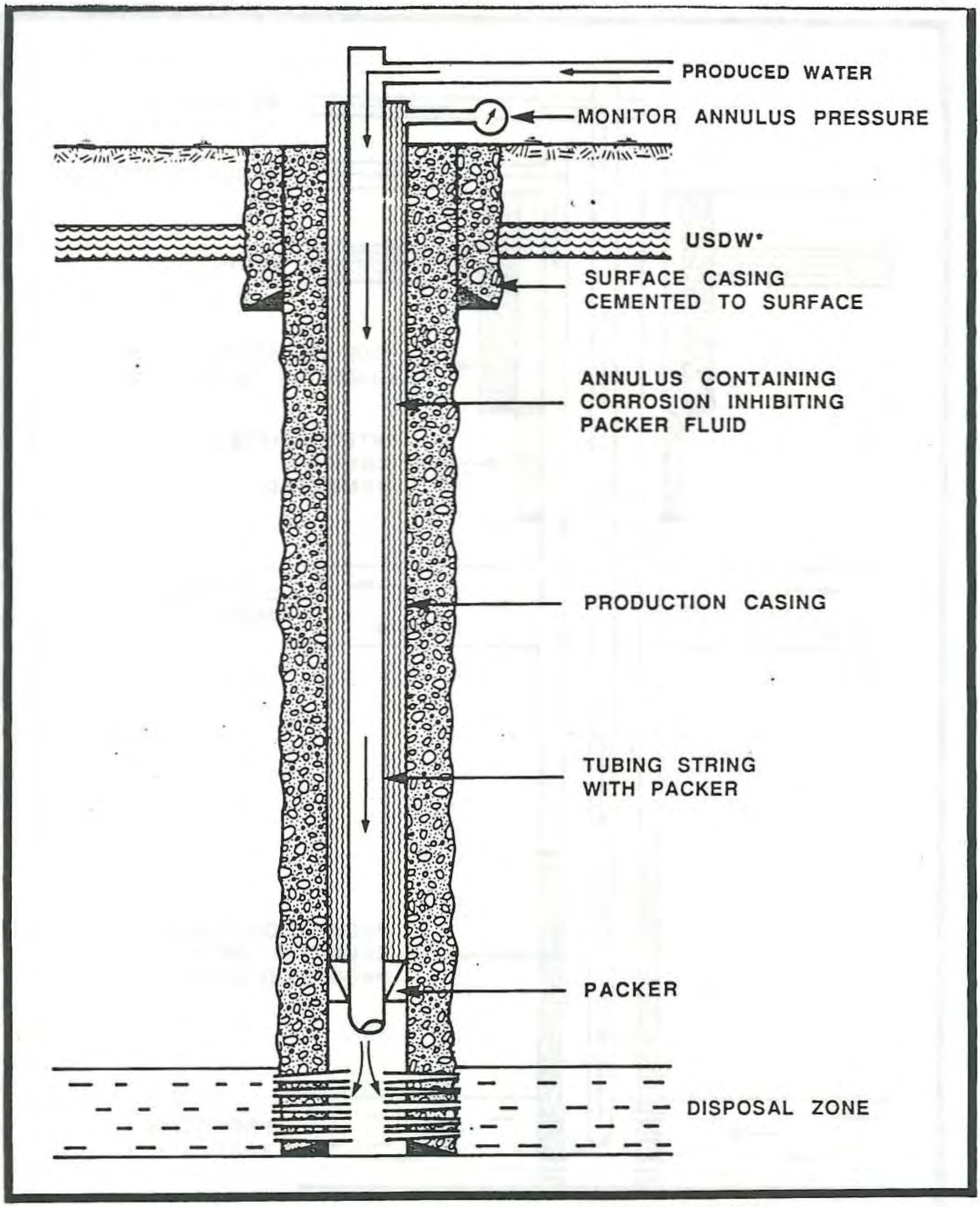
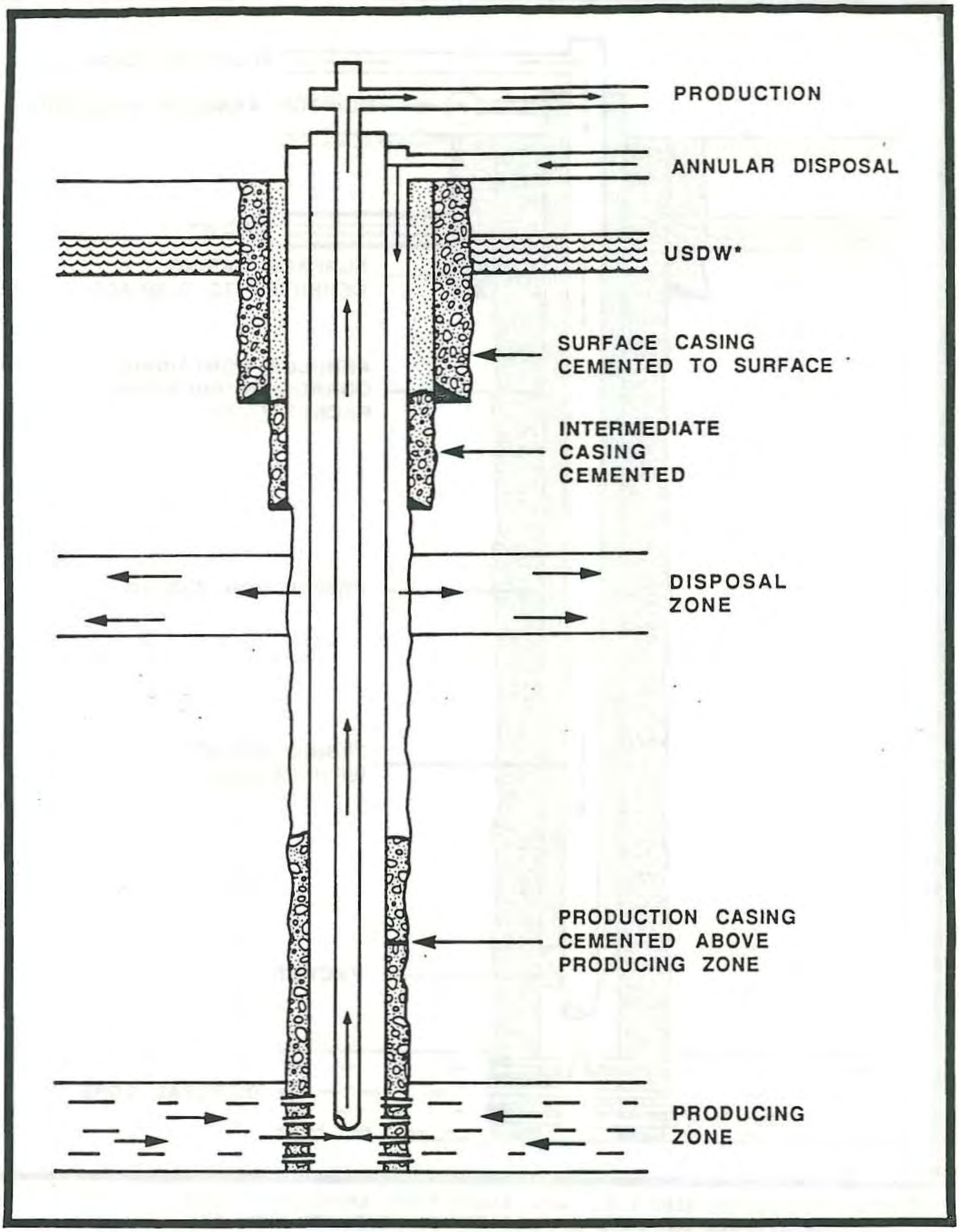
[9] In the State of Ohio, produced water is gravity-fed into the annulus rather than being pumped.



SOURCE: TEMPLETON, ELMER E., AND ASSOCIATES, ENVIRONMENTALLY ACCEPTABLE DISPOSAL OF SALT BRINES PRODUCED WITH OIL AND GAS, JANUARY, 1980.

* UNDERGROUND SOURCE OF DRINKING WATER
NOTE: NOT TO SCALE

Figure III-2 Typical Produced Water Disposal Well Design



SOURCE: TEMPLETON, ELMER E., AND ASSOCIATES, ENVIRONMENTALLY ACCEPTABLE DISPOSAL OF SALT BRINES PRODUCED WITH OIL AND GAS, JANUARY, 1980.

* UNDERGROUND SOURCE OF DRINKING WATER
NOTE: NOT TO SCALE

Figure III-3 Annular Disposal Outside Production Casing

Environmental performance: From the environmental standpoint, the primary issue with disposal of produced waters is the potential for chloride contamination of arable lands and fresh water. Other constituents in produced water may also affect the quality of ground water. Because of their high solubility in water, there is no practical way to immobilize chlorides chemically, as can be done with heavy metals and many other pollutants associated with oil and gas production.

Injection of produced water below all underground sources of drinking water is environmentally beneficial if proper safeguards exist to ensure that the salt water will reach a properly chosen disposal horizon, which is sufficiently isolated from usable aquifers. This can be accomplished by injecting water into played-out formations or as part of a waterflooding program to enhance recovery from a field. Problems to be avoided include overpressurization of the receiving formation, which could lead to the migration of the injected fluids or native formation fluids into fresh water via improperly completed or abandoned wells in the pressurized area. Another problem is leaking of injected fluids into freshwater zones through holes in the tubing and casing.

The UIC program attempts to prevent these potential problems. The EPA UIC program requires periodic mechanical integrity tests (MITs) to detect leaks in casing and ensure mechanical integrity of the injection well. Such testing can detect performance problems if it is conscientiously conducted on schedule. The Federal regulations require that mechanical integrity be tested for at least every 5 years. If leaks are detected or mechanical integrity cannot be established during the testing of the well, the response is generally to suspend disposal operations until the well is repaired or to plug and abandon the well if repair proves too costly or inefficient. The Federal regulations also require that whenever a new well or existing disposal well is permitted, a one-quarter mile radius around the well must be reviewed for the presence of manmade or natural conduits that could lead to injected fluids or native brines leaving the injection zone. In cases where improperly plugged or completed wells are found, the permit applicant must correct the problems or agree to limit the injection pressure. Major factors influencing well failure include the design, construction, and age of the well itself (converted producing wells, being older, are more likely to fail a test for integrity than newly constructed Class II injection wells); the corrosivity of the injected fluid (which varies chiefly in chloride content); and the injection pressure (especially if wastes are injected at pressures above specified permit limits).

Design, construction, operation, and testing: There is considerable variation in the actual construction of Class II wells in operation nationwide because many wells in operation today were constructed prior to enactment of current programs and because current programs themselves may vary quite significantly. The legislation authorizing the UIC program directed EPA to provide broad flexibility in its regulations so as not to impede oil and gas production, and to impose only requirements that are essential to the protection of USDWs. Similarly, the Agency was required to approve State programs for oil and gas wells whether or not they met EPA's regulations as long as they contained the minimum required by the Statute and were effective in protecting USDWs. For these reasons there is great variability in UIC requirements in both State-run and EPA-run programs. In general, requirements for new injection wells are quite extensive. Not every State, however, has required the full use of the "best available" technology. Furthermore, State requirements have evolved over time, and most injection wells operate with a lifetime permit. In practice, construction ranges from wells in which all USDWs are fully protected by two strings of casing and cementing, injection is through a tubing, and the injection zone is isolated by the packer and cement in the wellbore to shallow wells with one casing string, no packer, and little or no cement.

With respect to requirements for mechanical integrity testing of injection wells, Federal UIC requirements state that "an injection well has mechanical integrity if: (1) there is no significant leak in the casing, tubing or packer; and (2) there is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore." Translation of these general requirements into specific tests varies across States.

In addition to initial pressure testing prior to operation of injection wells, States (including those that do not have primacy under the UIC program) also require monitoring or mechanical integrity tests of Class II injection wells at least once every 5 years. In lieu of such a casing pressure test, the operator may, each month, monitor or record the pressure in the casing/tubing annulus during actual injection and report the pressure on a yearly basis.

To date, about 70 percent of all Class II injection wells have been tested nationwide, though statistics vary across EPA Regions. Data on these tests available at the Federal level are not highly detailed. Although Federal legislation lists a number of specific monitoring requirements (such as monitoring of injection pressures, volumes, and nature of fluid being injected and 5-year tests for mechanical integrity), technical information such as injection pressure and waste characterization is not reported at the Federal level. (These data are often kept at the State level.) Until recently, Federal data on mechanical integrity tests listed only the number of wells passing and failing within each State, without any explanation of the type of failure or its environmental consequences.

For injection wells used to access underground hydrocarbon storage and enhanced recovery, a well may be monitored on a field or project basis rather than on an individual well basis by manifold monitoring, provided the owner or operator demonstrates that manifold monitoring is comparable to individual well monitoring. Manifold monitoring may be used in cases where facilities consist of more than one injection well and operate with a common manifold. Separate monitoring systems for each well are not required provided the owner or operator demonstrates that manifold monitoring is comparable to individual well monitoring.

Under the Federal UIC program, all ground water with less than 10,000 mg/L total dissolved solids (TDS) is protected. Casing cemented to the surface is one barrier against contamination of USDWs. State programs vary in their requirements for casing and cementing. For example, Texas requires surface casing in strata with less than 3,000 ppm TDS; Louisiana, less than 1,500 ppm TDS; New Mexico, less than 5,000 ppm TDS. However, all wells must be designed to protect USDWs through a combination of surface casing, long string or intermediate casing, cementing, and geologic conditions.

Proximity to other wells and to protected aquifers: When a new injection well is drilled or an existing well is converted for injection, the area surrounding the site must be inspected to determine whether there are any wells of record that may be unplugged or inadequately plugged or any active wells that were improperly completed. The radius of concern includes that area within which underground pressures will be increased. All States have adopted at least the minimum Federal requirement of a one-quarter mile radius of review; however, the Agency is concerned that problems may still arise in instances where undocumented wells (such as dry holes) exist or where wells of record cannot be located.

States typically request information on the permit application about the proximity of the injection well to potable aquifers or to producing wells, other injection wells, or abandoned oil- or gas-producing wells within a one-quarter mile radius. In Oklahoma, for instance, additional restrictions are placed on UIC Class II wells within one-half mile of an active or reserve municipal water supply well unless the applicant can "prove by substantial evidence" that the injection well will not pollute a municipal water supply.

Although these requirements exist, it is important to recognize the following:

- Policy on review of nearby wells varies widely from State to State, and the injection well operator has had only a limited responsibility to identify possible channels of communication between the injection zone and freshwater zones.
- Many injection operations predate current regulations on the review of nearby wells and, because of "grandfather" clauses, are exempt.

Operation and maintenance: Incentives for compliance with applicable State or Federal UIC requirements will tend to vary according to whether a well is used for enhanced recovery or purely for waste disposal. Wells used for both purposes may be converted production wells or wells constructed specifically as Class II wells.

In order for enhanced recovery to be successful, it is essential for operators to ensure that fluids are injected into a specific reservoir and that pressures within the producing zone are maintained by avoiding any communication between that zone and others. Operators therefore have a strong economic incentive to be scrupulous in operating and maintaining Class II wells used for enhanced recovery.

On the other hand, economic incentives for careful operation of disposal wells may not be as strong. The purpose here is to dispose of fluids. The nature of the receiving zone itself, although regulated by State or Federal rules, is not of fundamental importance to the well operator as long as the receiving formation is able to accept injected fluids. Wells used for disposal are often older, converted production wells and may be subject to more frequent failures.

Evaporation and Percolation Pits

Description: Evaporation and percolation pits (see discussion above under "Reserve Pits") are also used for produced water disposal. An evaporation pit is defined as a surface impoundment that is lined by a clay or synthetic liner. An evaporation/percolation pit is one that is unlined.

Environmental performance: Evaporation of produced water can occur only under suitable climatic conditions, which limits the potential use of this practice to the more arid producing areas within the States. Percolation of produced water into soil has been allowed more often in areas where the ground water underlying the pit area is saline and is not suitable for use as irrigation water, livestock water, or drinking water. The use of evaporation and percolation pits has the potential to degrade usable ground water through seepage of produced water constituents into unconfined, freshwater aquifers underlying such pits.[10]

Discharge of Produced Waters to Surface Water Bodies

Description: Discharge of produced water to surface water bodies is generally done under the NPDES permit program. Under NPDES, discharges are permitted for (1) coastal or tidally influenced water, (2) agricultural and wildlife beneficial use, and (3) discharge of produced water from stripper oil wells to surface streams. Discharge under NPDES often occurs after the produced water is treated to control

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10 This phenomenon is documented in Chapter IV.

pH and minimize a variety of common pollutants, such as oil and grease, total dissolved solids, and sulfates. Typical treatment methods include simple oil and grease separation followed by a series of settling and skimming operations.

Environmental performance: Direct discharge of produced waters must meet State or Federal permit standards. Although pollutants such as total organic carbon are limited in these discharges, large volumes of discharges containing low levels of such pollutants may be damaging to aquatic communities.[11]

Other Production-Related Pits

Description: A wide variety of pits are used for ancillary storage and management of produced waters and other production-related wastes. These can include:[12]

1. Basic sediment pit: Pit used in conjunction with a tank battery for storage of basic sediment removed from a production vessel or from the bottom of an oil storage tank. (Also referred to as a burn pit.)

2. Brine pit: Pit used for storage of brine used to displace hydrocarbons from an underground hydrocarbon storage facility.

3. Collecting pit: Pit used for storage of produced water prior to disposal at a tidal disposal facility, or pit used for storage of produced water or other oil and gas wastes prior to disposal at a disposal well or fluid injection well. In some cases, one pit is both a collecting pit and a skimming pit.

4. Completion/workover pit: Pit used for storage or disposal of spent completion fluids, workover fluids, and drilling fluid; silt; debris; water; brine; oil; scum; paraffin; or other materials that have been cleaned out of the wellbore of a well being completed or worked over.

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11 This phenomenon is documented in Chapter IV.

12 List adapted from Texas Railroad Commission Rule 8, amended March 5, 1984.

5. Emergency produced water storage pit: Pit used for storage of produced water for a limited period of time. Use of the pit is necessitated by a temporary shutdown of a disposal well or fluid injection well and/or associated equipment, by temporary overflow of produced water storage tanks on a producing lease, or by a producing well loading up with formation fluids such that the well may die. Emergency produced water storage pits may sometimes be referred to as emergency pits or blowdown pits.

6. Flare pit: Pit that contains a flare and that is used for temporary storage of liquid hydrocarbons that are sent to the flare during equipment malfunction but are not burned. A flare pit is used in conjunction with a gasoline plant, natural gas processing plant, pressure maintenance or repressurizing plant, tank battery, or well.

7. Skimming pit: Pit used for skimming oil off produced water prior to disposal of produced water at a tidal disposal facility, disposal well, or fluid injection well.

8. Washout pit: Pit located at truck yard, tank yard, or disposal facility for storage or disposal of oil and gas waste residue washed out of trucks, mobile tanks, or skid-mounted tanks.[13]

   The Wyoming Oil and Gas Conservation Commission would add pits that retain fluids for disposal by evaporation such as pits used for gas wells or pits used for dehydration facilities.

Environmental performance: All of these pits may cause adverse environmental impact if their contents leach, if they are improperly closed or abandoned, or if they are used for improper purposes. Although they are necessary and useful parts of the production process, they are subject to potential abuse. An example would be the use of an emergency pit for disposal (through percolation or evaporation) of produced water.

Offsite Management Methods

Road or Land Applications

Description: Untreated produced water is sometimes disposed of by application to roads as a deicing agent or for dust control.

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[13] The Alaska Department of Environmental Conservation questions whether pits described in Items 1, 6, and 8 should be exempt under RCRA.

Environmental performance: Road or land application of produced waters may cause contamination of ground water through leaching of produced water constituents to unconfined freshwater aquifers. Many States do not allow road or land application of produced waters.

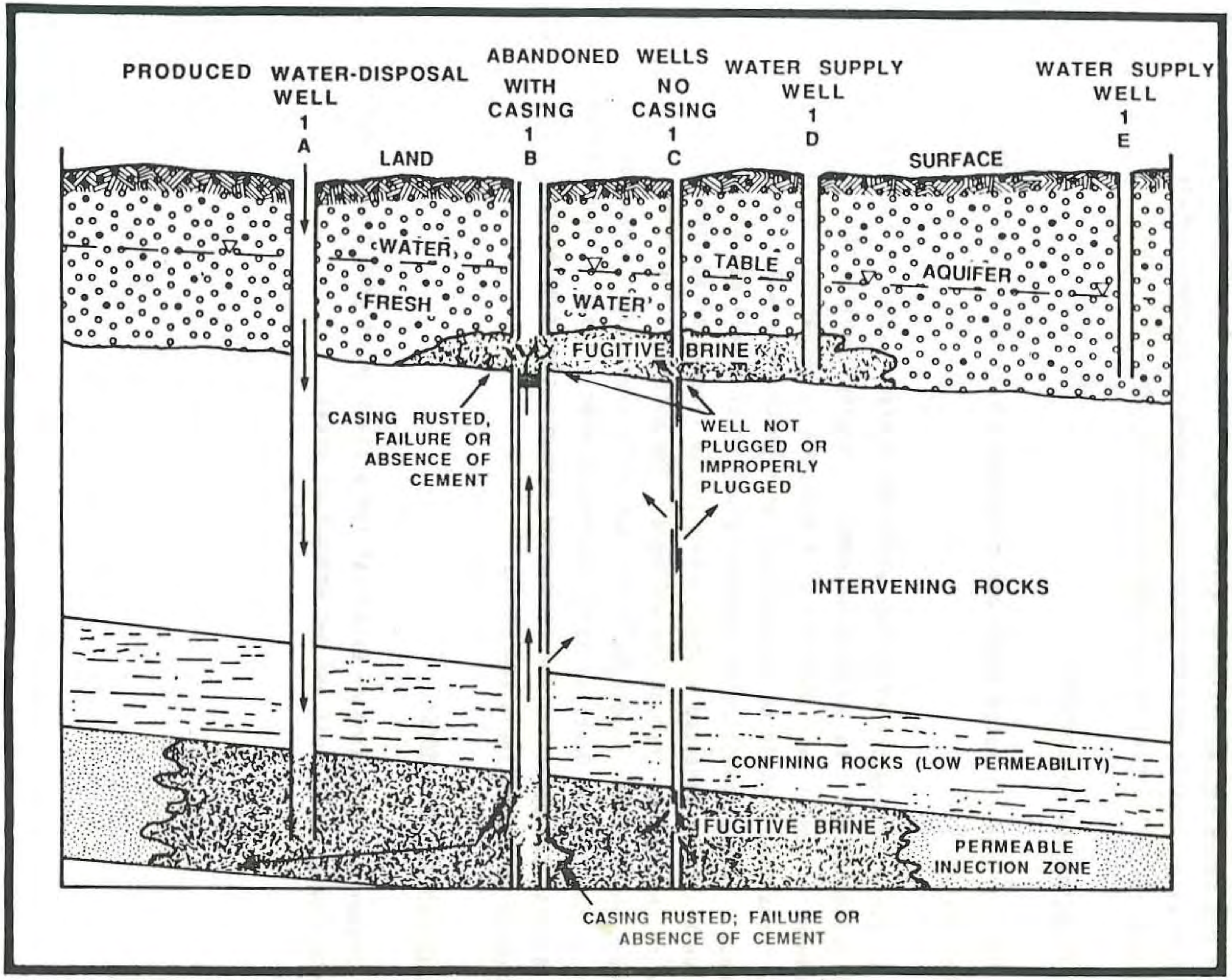
Well Plugging and Abandonment

There are an estimated 1,200,000 abandoned oil or gas wells in the United States.

To avoid degradation of ground water and surface water, it is vital that abandoned wells be properly plugged. Plugging involves the placement of cement over portions of a wellbore to permanently block or seal formations containing hydrocarbons or high-chloride waters (native brines). Lack of plugging or improper plugging of a well may allow native brines or injected wastes to migrate to freshwater aquifers or to come to the surface through the wellbore. The potential for this is highest where brines originate from a naturally pressurized formation such as the Coleman Junction formation found in West Texas. Figure III-4 illustrates the potential for freshwater contamination created by abandoned wells (Illinois EPA 1978).

Environmental Performance

Proper well plugging is essential for protection of ground water and surface water in all oil and gas production areas.



SOURCE: ILLINOIS EPA, ILLINOIS OIL FIELD BRINE DISPOSAL ASSESSMENT: STAFF REPORT, NOVEMBER 1978.

NOTE: NOT TO SCALE

Figure III-4 Pollution of a Fresh Water Aquifer Through Improperly

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CHAPTER IV

DAMAGE CASES

INTRODUCTION

Purpose of the Damage Case Review

The damage case study effort conducted for this report had two principal objectives:

<u>To Respond to the Requirements of Section 8002(m)(C)</u>

The primary objective was to respond to the requirements of Section 8002(m) of RCRA, which require EPA to identify documented cases that prove or have caused danger to human health and the environment from surface runoff or leachate. In interpreting this passage, EPA has emphasized the importance of strict documentation of cases by establishing a test of proof (discussed below) that all cases were required to pass before they could be included in this report. In addition, EPA has emphasized development of recent cases that illustrate damages created by <u>current</u> practices under <u>current</u> State regulations. This has been complicated in some instances by recent revisions to regulatory requirements in some States. The majority of cases presented in this chapter (58 out of 61) occurred during the last 5 years. Historical damages that occurred under prior engineering practices or under previous regulatory regimes have been excluded unless such historical damages illustrate health or environmental problems that the Agency believes should be brought to the attention of Congress now.[1] The overall objective is to present documented cases that show reasonably clear links of cause and effect between waste management practices and resulting damages, and to identify cases where damages have been most significant in terms of human health or environmental impacts.

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[1] The primary example of this is the problem of abandoned wells, discussed at length under <u>Miscellaneous Issues</u> below. The abandoned well problem results for the most part from inadequate past plugging practices. Although plugging practices have since been improved under State regulations, associated damages to health and the environment are continuing.

To Provide an Overview of the Nature of Damages Associated with Oil and Gas Exploration, Development, or Production Activities

In the course of accumulating damage cases, EPA has acquired a significant amount of information that has provided helpful insights into the nature of damages.

Methodology for Gathering Damage Case Information

The methodology for identifying, collecting, and processing damage cases was originally presented in draft form in the Technical Report published on October 31, 1986. The methodology, which differs minimally from the draft, is outlined below.

Information Categories

The damage case effort attempted to collect and record several categories of information on each case. Initially, this information was organized into a data base from which portions of cases were drawn for use in the final report. Categories of information were as follows:

1. Characterization of specific damage types: For each case, the environmental medium involved was determined (ground water, surface water, or land), along with the type of incident and characterization of damage. Only cases with documented damage were included. Types of potential health or environmental damages of interest are shown on Table IV-1.

2. The size and location of the site: Sites were located by nearest town and by county. Where significant hydrogeological or other pertinent factors are known, they were included; however, this type of information has been difficult to gather for all cases.

3. The operating status of the facility or site: All pertinent factors relating to the site's status (active, inactive, in process of shutdown, etc.) have been noted.

Table IV-1 Types of Damage of Concern to This Study

1. Human Health Effects (acute and chronic): While there are some instances where contamination has resulted in cases of acute adverse human health effects, such cases are difficult to document. Levels of pollution exposure caused by oil and gas operations are more likely to be in ranges associated with chronic carcinogenic and noncarcinogenic effects.

2. Environmental Effects: Impairment of natural ecosystems and habitats, including contaminating of soils, impairment of terrestrial or aquatic vegetation, or reduction of the quality of surface waters.

3. Effects on Wildlife: Impairment to terrestrial or aquatic fauna; types of damage may include reduction in species' presence or density, impairment of species' health or reproductive ability, or significant changes in ecological relationships among species.

4. Effects on Livestock: Morbidity or mortality of livestock, impairment in the marketability of livestock, or any other adverse economic or health-based impact on livestock.

5. Impairment of Other Natural Resources: Contamination of any current or potential source of drinking water, disruption or lasting impairment to agricultural lands or commercial crops, impairment of potential or actual industrial use of land, or reduction in current or potential use of land.

4. Identification of the type and volume of waste involved: While the type of waste involved has been easy to define, volumes often have not.

5. Identification of waste management practices: For each incident, the waste management practices associated with the incident have been presented.

6. Identification of any pertinent regulations affecting the site: State regulations in force across the oil- and gas-producing States are discussed at length in Appendix A. Since it would be unwieldy to attempt to discuss all pertinent regulations in relation to each site, each documented case includes a section on Compliance Issues that discusses significant regulatory issues associated with each incident as reported by sources or contacts.[2] In some cases, interpretations were necessary.

7. Type of documentation available: All documentation available for each case was included to the extent possible. For a few cases, documentation is extensive.

For the purpose of this report, the data base was condensed and is presented in Appendix C.

Sources and Contacts

No attempt was made to compile a complete census of current damage cases. States from which cases were drawn are listed on Table IV-2. As evident from the table, resources did not permit gathering of cases from all States.

Within each of the States, every effort was made to contact all available source categories listed in the Technical Report (see Table IV-3). Because time was extremely limited, the effort relied principally on information available through relevant State and local agencies and

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[2] All discussions have been reviewed by State officials and by any other sources or contacts who provided information on a case.

Table IV-2 States From Which Case Information Was Assembled

1. Alaska
2. Arkansas
3. California
4. Colorado
5. Kansas
6. Louisiana
7. Michigan
8. New Mexico
9. Ohio
10. Oklahoma
11. Pennsylvania
12. Texas
13. West Virginia
14. Wyoming

Table IV-3 Sources of Information Used in Developing Damage Cases

1. Relevant State or Local Agencies: including State environmental agencies; oil and gas regulatory agencies; State, regional, or local departments of health; and other agencies potentially knowledgeable about damages related to oil and gas operations.
2. EPA Regional Offices
3. Bureau of Land Management
4. Forest Service
5. Geological Survey
6. Professional or trade associations
7. Public interest or citizens' groups
8. Attorneys engaged in litigation

on contacts provided through public interest or citizens' groups. In some instances, cases were developed through contacts with private attorneys directly engaged in litigation. Because these nongovernmental sources often provided information on incidents of which State agencies were unaware, such cases were sometimes undocumented at the State level. State agencies were, however, provided with review drafts of case write-ups. They, in turn, provided extensive additional information and comments.

Case Study Development

Virtually all of the data used here were gathered through direct contacts with agencies and individuals, or through followup to those contacts, rather than through secondary references. For each State, researchers first contacted all State agencies that play a significant role in the regulation of oil or gas operations and set up appointments for field visits. At the same time, contacts and appointments were made where possible with local citizens' groups and private attorneys in each State. Visits were made in the period between December 1986 and February 1987. During that time, researchers gathered actual documentation and made as many additional contacts as possible.

Test of Proof

All cases were classified according to whether they met one or more formal tests of proof, a classification that was to some extent judgmental. Three tests were used, and cases were considered to meet the documentation standards of 8002(m)(C) if they met one or more of them.

The tests were as follows:

1. Scientific investigation: A case could meet documentation standards if damages were found to exist as part of the findings of a scientific study. Such studies could be extensive formal investigations supporting litigation or a State enforcement action, or they could, in some instances, be the results of technical tests (such as monitoring of wells) if such tests (a) were conducted with State-approved quality control procedures, and (b) revealed contamination levels in excess of an applicable State or Federal standard or guideline (such as a drinking water standard or water quality criterion).

2. Administrative ruling: A case could meet documentation standards if damages were found to exist through a formal administrative finding, such as the conclusions of a site report by a field investigator, or through existence of an enforcement action that cited specific health or environmental damages.

3. Court decision: The third way in which a case could be accepted was if damages were found to exist through the ruling of a court or through an out-of-court settlement.

EPA considered the possibility of basing its damage case review solely on cases that have been tried in court and for which damage determinations have been made by jury or judicial decision. This approach was rejected for a variety of reasons. First and most important, EPA wanted wherever possible to base its damage case work on scientific evidence and on evidence developed by States as part of their own regulatory control programs. Since States are the most important entity in controlling the environmental impacts of this industry, the administrative damage determinations they make are of the utmost concern to EPA. Second, comparatively few cases are litigated, and many litigated cases, perhaps a majority, are settled out of court and their records sealed through agreements between plaintiffs and defendants. Third, as data collected for this report indicate, many litigated cases are major cases in which the plaintiff may be a corporation or a comparatively wealthy landowner with the resources necessary to develop the detailed evidence necessary to successfully litigate a private suit (see damage case LA 65 on pages IV-78 and IV-79). Private citizens rarely bring cases to court because court cases are expensive to conduct, and most of these cases are settled out of court.

Review by State Groups and Other Sources

All agencies, groups, and individuals who provided documentation or who have jurisdiction over the sites in any specific State were sent draft copies of the damage cases. Because of the tight schedule for development of the report, there was limited time available for damage case review. Their comments were incorporated to the extent possible; EPA determined which comments should be included.

Limitations of the Methodology and Its Results

Schedule for Collection of Damage Case Information

The time period over which the damage case study work occurred was short, covering portions of three consecutive months. In addition, much of the field research was arranged or conducted over the December 1986-January 1987 holiday period, when it was often difficult to make contacts with State agency representatives or private groups. To the extent that resources permitted, followup visits were made to fill gaps. Nevertheless, coverage of some States had to be omitted entirely, and coverage in others (particularly Oklahoma) was limited.

Limited Number of Oil- and Gas-Producing States in Analysis

Of the States originally intended to be covered as discussed in the Technical Report, several were omitted from coverage; however, States visited account for a significant percentage of U.S. oil and gas production (see Table IV-2).

Difficulty in Obtaining a Representative Sample

In general, case studies are used to gain familiarity with ranges of issues involved in a particular study topic, not to provide a statistical representation of damages. Therefore, although every attempt was made to produce representative cases of damages associated with oil and gas operations, this study does not assert that its cases are a statistically representative record of damages in each State. Even if an attempt had been made to create a statistically valid study set, such as by randomly selecting drilling operations for review, it would have been difficult for a number of practical reasons.

First, record keeping varies significantly among States. A few States, such as Ohio, have unusually complete and up-to-date central records of enforcement actions and complaints. More often, however, enforcement records are incomplete and/or distributed throughout regional offices within the State. Schedules were such that only a few offices, usually only the State's central offices, were visited by researchers. Furthermore, their ability to collect files at each office was limited by the time available on site (usually 1 day, but never more than 3 days) and by the ability of each State to spare staff time to assist in the research. The number of cases found at each office and the amount of material gathered were influenced strongly by these constraints.

Second, very often damage claims against oil and gas operators are settled out of court, and information on known damage cases has often been sealed through agreements between landowners and oil companies.

This is typical practice, for instance, in Texas. In some cases, even the records of well-publicized damage incidents are almost entirely unavailable for review. In addition to concealing the nature and size of any settlement entered into between the parties, impoundment curtails access to scientific and administrative documentation of the incident.

A third general limitation in locating damage cases is that oil and gas activities in some parts of the country are in remote, sparsely populated, and unstudied areas. In these areas, no significant population is present to observe or suffer damages, and access to sites is physically difficult. To systematically document previously unreported damages associated with operations in more remote areas would have required an extensive original research project far beyond the resources available to this study.

Organization of This Presentation

As noted throughout this report, conditions affecting exploration, development, and production of oil and gas vary extensively from State to State, and by regions within States. While it would be logical to discuss damage cases on a State-by-State basis, the following discussion is organized according to the zones defined for other purposes in this project. Within each zone the report presents one or more categories of damages that EPA has selected as fairly illustrative of practices and conditions within that zone, focusing principally on cases of damage associated with management of high-volume wastes (drilling fluids and produced waters). Wherever possible, State-specific issues are discussed as well.

At the end of this chapter are a number of miscellaneous categories of damage cases that, although significant and well-documented, are associated either with management of lower volume exempt wastes or with types of damage not immediately related to management of wastes from current field operations. Such categories include damages caused by unplugged or improperly plugged abandoned wells.

NEW ENGLAND

The New England zone includes Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut. No significant oil and gas are found in this zone, and no damage cases were collected.

APPALACHIA

The Appalachian zone includes Delaware, Kentucky, Maryland, New Jersey, New York, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. Many of these States have minimal oil and gas production. Damage cases were collected from Ohio, West Virginia, and Pennsylvania.

Operations

Oil and gas production in the Appalachian Basin tends to be marginal, and operations are often low-budget efforts. Funds for proper maintenance of production sites may be limited. Although the absolute amount of oil produced in the Appalachian zone is small in comparison with the rest of the country, the produced water-to-product ratios are typically very high and produced waters contain high concentrations of chlorides.[3]

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[3] David Flannery, on behalf of various oil and gas trade organizations, states that "...in absolute terms, the discharge of produced water from wells in the Appalachian states is small."

In West Virginia in 1985, 1,839 new wells were completed at an average depth of 4,270 feet. Only 18 exploratory wells were drilled in that year. In Pennsylvania 4,627 new wells were completed in 1985 to an average depth 2,287 feet; 59 exploratory wells were drilled in that year. Activity in Ohio is developmental rather than exploratory, with only 78 exploratory wells drilled in 1985 out of a total of 6,297 wells completed. The average depth of a new well in 1985 was 3,760 feet.

Types of Operators

Oil and gas production in the Appalachian Basin is dominated by small operators, some well-established, some new to the industry. Major companies still hold leases in some areas. Since most extraction in this zone is economically marginal, many operators are susceptible to market fluctuations.

Major Issues

Contamination of Ground Water from Reserve Pits

Damage case incidents resulting from unlined reserve pits, with subsequent migration of contaminants into ground water, are found in the State of Ohio.

> In 1982, drilling activities of an unnamed oil and gas company contaminated the well that served a house and barn owned by a Mr. Bean, who used the water for his dairy operations. Analysis done on the water well by the Ohio Department of Agriculture found high levels of barium, iron, sodium, and chlorides. (Barium is a common constituent of drilling mud.) Because the barium content of the water well exceeded State standards, Mr. Bean was forced to shut down his dairy operations. Milk produced at the Bean farm following contamination of the water well contained 0.63 mg/L of barium. Concentrations of chlorides, barium, iron, sodium, and other residues in the water well were above the U.S. EPA's Secondary Drinking Water Standards. Mr. Bean drilled a new well, which also became contaminated. As of September 1984, Mr. Bean's water

well was still showing signs of contamination from the drilling-related wastes. It is not known whether Mr. Bean was able to recover financially from the disruption of his dairy business. (OH 49)[4]

This case is a violation of current Ohio regulations regarding drilling mud and produced waters.

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Illegal Disposal of Oil Field Wastes in Ohio

Illegal disposal of oil field wastes is a problem in Ohio, as elsewhere, but the State is making an aggressive effort to increase compliance with State waste disposal requirements and is trying to maintain complete and up-to-date records. The State has recently banned all saltwater disposal pits. A legislative initiative during the spring of 1987 attempted to overturn the ban. The attempt was unsuccessful.

The Miller Sand and Gravel Co., thougn an active producer of sand and gravel, has also served as an illegal disposal site for oil field wastes. An investigation by the Ohio Department of Natural Resources (DNR) found that the sand and gravel pits and the surrounding swamp were contaminated with oil and high-chloride produced waters. Ohio inspectors noted a flora kill of unspecified size. Ohio Department of Health laboratory analysis of soil and liquid samples from the pits recorded chloride concentrations of 269,000 mg/L. The surrounding swamp chloride concentrations ranged from 303 mg/L (upstream from the pits) to 60,000 mg/L (area around the pits). This type of discharge is prohibited by State regulations. (OH 45)[5]

This discharge was a violation of State regulations.

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[4] References for case cited: Ohio EPA, Division of Public Water Supply, Northeast District Office, interoffice communication from E. Mohr to M. Hilovsky describing test results on Mr. Bean's water well, 7/21/86. Letters from E. Mohr, Ohio EPA, to Mr. Bean and Mr. Hart explaining water sampling results, 10/20/82. Letter from Miceli Dairy Products Co. to E. Mohr, Ohio EPA, explaining test results from Mr. Bean's milk and water well. Letters from E. Mohr, Ohio EPA, to Mr. Bean explaining water sampling results from tests completed on 10/7/82, 2/2/83, 10/25/83, 6/15/84, 8/3/84, and 9/17/84. Generalized stratigraphic sequence of the rocks in the Upper Portion of the Grand River Basin.

[5] References for case cited: Ohio EPA, Division of Wastewater Pollution Control, Northeast District Office, interoffice communication from E. Mohr to D. Hasbrauck, District Chief, concerning the results from sampling at the sand and gravel site. Ohio Department of Health, Environmental Sample Submission Reports from samples taken on 6/22/82.

Equity Oil & Gas Funds, Inc., operates Well #1 on the Engle Lease, Knox County. An Ohio DNR official inspected the site on April 5, 1985. There were no saltwater storage tanks on site to collect the high-chloride produced water that was being discharged from a plastic hose leading from the tank battery into a culvert that, in turn, emptied into a creek. The inspector took photos and samples. Both produced water and oil and grease levels were of sufficient magnitude to cause damage to flora and fauna, according to the notice of violation filed by the State. The inspector noted that a large area of land along the culvert had been contaminated with oil and produced water. The suspension order indicated that the "...violations present an imminent danger to public health and safety and are likely to result in immediate and substantial damage to natural resources." The operator was required by the State to "...restore the disturbed land surface and remove the oil from the stream in accordance with Section 1509.072 of Ohio Revised Statutes...." (OH 07)[6]

This was an illegal discharge that violated Ohio regulations. In another case:

Zenith Oil & Gas Co. operated Well #1 in Hopewell Township. The Ohio DNR issued a suspension order to Zenith in March of 1984 after State inspectors discovered produced water discharges onto the surrounding site from a breech in a produced water pit and pipe leading from the pit. A Notice of Violation had been issued in February 1984, but the violations were still in effect in March 1984. A State inspection of an adjacent site, also operated by Zenith Oil & Gas Co., discovered a plastic hose extending from one of the tank batteries discharging high-chloride produced water into a breached pit and onto the site surface. Another tank was discharging produced water from an open valve directly onto the site surface. State inspectors also expressed concern about lead and mercury contamination from the discharge. Lead levels in the discharge were 2.5 times the accepted level for drinking water, and mercury levels were 925 times the acceptable levels for drinking water, according to results filed for the State by a private laboratory. The State issued a suspension order stating that the discharge was "...causing contamination and pollution..." to the surface and subsurface soil, and in order to remedy the problem the operator would have to restore the disturbed land. (Ohio no longer allows the use of produced water disposal pits.) (OH 12)[7]

This was an illegal discharge that violated Ohio regulations.

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[6] References for case cited: The Columbus Water and Chemical Testing Lab, lab reports. Ohio Department of Natural Resources, Division of Oil and Gas, Notice of Violation, 5/5/85.

[7] References for case cited: Ohio Department of Natural Resources, Division of Oil and Gas, Suspension Order #84-07, 3/22/84. Muskingum County Complaint Form. Columbus Water and Chemical Testing Lab sampling report.

Contamination of Ground Water from Annular Disposal of Produced Water

Ohio allows annular disposal of produced waters. This practice is not widely used elsewhere because of its potential for creating ground-water contamination. Produced water containing high levels of chlorides tends to corrode the single string of casing protecting ground water from contamination during annular disposal. Such corrosion creates holes in a well's casing that can allow migration of produced water into ground water. Under the Federal UIC program, Ohio requires operators of annular disposal wells to conduct radioactive tracer surveys to determine whether produced water is being deposited in the correct formations. Tracer surveys are more expensive than conventional mechanical integrity tests for underground injection wells, and only 2 percent of all tracer surveys were witnessed by DNR inspectors in 1985.

The Donofrio well was a production oil well with an annular disposal hookup fed by a 100-bbl produced water storage tank. In December 1975, shortly after completion of the well, tests conducted by the Columbus Water and Chemical Testing Lab on the Donofrio residential water well showed chloride concentrations of 4,550 ppm. One month after the well contamination was reported, several springs on the Donofrio property showed contamination from high-chloride produced water and oil, according to Ohio EPA inspections. On January 8, 1976, Ohio EPA investigated the site and reported evidence of oil overflow from the Donofrio well production facility, lack of diking around storage tanks, and the presence of several produced water storage pits. In 1986, 11 years after the first report of contamination, a court order was issued to disconnect the annular disposal lines and to plug the well. The casing recovered from the well showed that its condition ranged from fair to very poor. The casing was covered with rust and scale, and six holes were found.[8] (OH 38)[9]

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8 Comments in the Docket by David Flannery and American Petroleum Institute (API) pertain to OH 38. Mr. Flannery states that "...the water well involved in that case showed contamination levels which predated the commencement of annular disposal...." EPA believes this statement refers to bacterial contamination of the well discovered in 1974. (EPA notes that the damage case discusses chloride contamination of the water well, not bacterial contamination.)

9 References for case cited: Ohio Department of Natural Resources, Division of Oil and Gas, interoffice communication from M. Sharrock to S. Kell on the condition of the casing removed from the Donofrio well. Communication from Attorney General's Office, E.S. Post, discussing court order to plug the Donofrio well. Perry County Common Pleas Court Case #19262. Letter from R.M. Kimball, Assistant Attorney General, to Scott Kell, Ohio Department of Natural Resources, presenting case summary from 1974 to 1984. Ohio Department of Health lab sampling reports from 1976 to 1985. Columbus Water and Chemical Testing Lab, sampling reports from 12/1/75, 7/27/84, and 8/3/84.

This well could not pass the current criteria for mechanical integrity under the UIC program.

An alternative to annular disposal of oil field waste is underground injection in Class II wells, using tubing and packer, but these Class II disposal wells are significantly more expensive than annular disposal operations.

Illegal Disposal of Oil and Gas Waste in West Virginia

Environmental damage from illegal disposal of wastes associated with drilling and production is by far the most common type of problem in West Virginia. Results of illegal disposal include fish kills, vegetation kills, and death of livestock from drinking polluted water. Fluids illegally disposed of include oil, produced waters of up to 180,000 ppm chlorides, drilling fluids, and fracturing fluids that can have a pH of as low as 3.0 (highly acidic).

Illegal disposal in this State takes many forms, including draining of saltwater holding tanks into streams, breaching of reserve pits into streams, siphoning of pits into streams, or discharging of vacuum truck contents into fields or streams.

Enforcement is difficult both because of limited availability of State inspection and enforcement personnel and because of the remote location of many drill sites (see Table VII-7). Many illegal disposal incidents come to light through complaints from landowners or anonymous informers.

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Beginning in 1979, Allegheny Land and Mineral Company of West Virginia operated a gas well, #A-226, on the property of Ray and Charlotte Willey. The well was located in a corn field where cattle were fed in winter, and within 1,000 feet of the Willey's residence. The well was also adjacent to a stream known as the Beverlin Fork. Allegheny Land and Mineral operated another gas well above the residence known as the #A-306, also located on property owned by the Willeys. Allegheny Land and Mineral maintained open reserve pits and an open waste ditch, which ran into Beverlin Fork. The ditch served to dispose of produced water, oil, drip gas, detergents, fracturing fluids, and waste production chemicals. Employees of the company told the Willeys that fluids in the pits were safe for their livestock to drink.

The Willeys alleged that their cattle drank the fluid in the reserve pit and became poisoned, causing abortions, birth defects, weight loss, contaminated milk, and death. Hogs were also allegedly poisoned, resulting in infertility and pig still-births, according to the complaint filed in the circuit court of Doddridge County, by the Willeys, against Allegheny Land and Mineral. The Willeys claimed that the soil on the farm was contaminated, causing a decrease in crop production and quality; that the ground water of the farm was contaminated, polluting the water well from which they drew their domestic water supply; and that the value of their real estate had been diminished as a result of these damages. Laboratory tests of soil and water from the property confirmed this contamination. The Willeys incurred laboratory expenses in having testing done on livestock, soil, and water. A judgment filed in the circuit court of Doddridge County was entered in 1983 wherein the Willeys were awarded a cash settlement in court for a total of $39,000 plus interest and costs.[10] (WV 18)[11]

This practice would violate current West Virginia regulations.

On February 23, 1983, Tom Ancona, a fur trapper, filed a complaint concerning a fish kill on Stillwell Creek. A second complaint was also filed anonymously by an employee of Marietta Royalty Co. Ancona, accompanied by a State fisheries biologist, followed a trail consisting of dead fish, frogs, and salamanders up to a drill site operated by Marietta Royalty Co., according to the complaint filed with the West Virginia DNR. There they found a syphon hose draining the drilling waste pit into a tributary of Stillwell Creek. Acid levels at the pit measured a pH of 4.0, enough to shock and kill aquatic life, according to West Virginia District Fisheries Biologist Scott Morrison. Samples and photographs were taken by the DNR. No dead aquatic life was found above the sample

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[10] West Virginia Department of Energy states that "...now the Division does not allow that type of practice, and would not let a landowner subvert the reclamation law."

[11] References for case cited: Complaint form filed in circuit court of Doddridge County, West Virginia, #81-c-18. Judgment form filed in circuit court of Doddridge County, West Virginia. Water quality summary of Ray Willey farm. Letter from D. J. Horvath to Ray Willey. Water analysis done by Mountain State Environmental Service. Veterinary report on cattle and hogs of Willey farm. Lab reports from National Veterinary Services Laboratories documenting abnormalities in Willey livestock.

site. Marietta Royalty Co. was fined a total of $1,000 plus $30 in court costs.[12] (WV 20)[13]

This discharge was in direct violation of West Virginia regulations.

Illegal Disposal of Oil Field Waste in Pennsylvania

In Pennsylvania, disposing of oil and gas wastes into streams prior to 1985 violated the State's general water quality criteria, but the regulations were rarely enforced. In a study conducted by the U. S. Fish and Wildlife Service, stream degradation was found in relation to chronic discharges to streams from oil and gas operations:

> The U.S. Fish and Wildlife Service conducted a survey of several streams in Pennsylvania from 1982-85 to determine the impact on aquatic life over a period of years resulting from discharge of oil field wastes to streams. The area studied has a history of chronic discharges of wastes from oil and gas operations. The discharges were primarily of produced water from production and enhanced recovery operations. The streams studied were Miami Run, South Branch of Cole Creek, Panther Run, Foster Brook, Lewis Run, and Pithole Creek. The study noted a decline downstream from discharges in all fish populations and populations of frogs, salamanders, and crayfish. (PA 02)[14]

These discharges of produced waters are presently allowed only under the National Pollutant Discharge Elimination System (NPDES) permit system.

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[12] The West Virginia Department of Energy states that "This activity has now been regulated under West Virginia's general permit for drilling fluids. Under that permit there would have been no environmental damage."

[13] References for case cited: Complaint Form #6/170/83, West Virginia Department of Natural Resources, 2/25/83. West Virginia Department of Natural Resources Incident Reporting Sheet, 2/26/83. Sketches of Marietta drill site. Complaint for Summons or Warrant, 3/28/83. Summons to Appear, 3/18/83. Marietta Royalty Prosecution Report, West Virginia Department of Natural Resources. Interoffice memorandum containing spill investigation details on Marietta Royalty incident.

[14] References for case cited: U.S. Fish and Wildlife, Summary of Data from Five Streams in Northwest Pennsylvania, 3/85. Background information on the streams selected for fish tissue analysis, undated but after 10/23/85. Tables 1 through 3 on point source discharge samples collected in the creeks included in this study, undated but after 10/30/84.

The long-term environmental impacts of chronic, widespread illegal disposal include loss of aquatic life in surface streams and soil salt levels above those tolerated by native vegetation. In 1985, Pennsylvania established State standards concerning this type of discharge. Discharges are now permitted under the NPDES system.

The northwestern area of Pennsylvania was officially designated as a hazardous spill area (Clean Water Act, Section 311(k)) by the U.S.EPA in 1985 because of the large number of oily waste discharges that have occurred there. Even though spills are accidental releases, and thus do not constitute wastes routinely associated with the extraction of oil and gas under the sense of the 3001 exemption, spills in this area of Pennsylvania appear to represent deliberate, routine, and continuing illegal disposal of waste oil.

Breaching of pits, opening of tank battery valves, and improper oil separation have resulted in an unusually high number of sites discharging oil directly to streams. The issue was originally brought to the attention of the State through a Federal investigation of the 500,000 acre Allegheny National Forest. That investigation discovered 500 separate spills. These discharges have affected stream quality, fish population, and other related aquatic life.

The U.S. EPA declared a four-county area (including Mckean, Warren, Venango, and Elk counties) a major spill area in the summer of 1985. The area is the oldest commercial oil-producing region in the world. Chronic low-level releases have occurred in the region since earliest production and continue to this day. EPA and other agencies (e.g., U.S. Fish and Wildlife, Pennsylvania Fish and Game, Coast Guard) were concerned that continued discharge into the area's streams has already and will in the future have major environmental impact. The area is dotted with thousands of marginal stripper wells (producing a high ratio of produced water to oil), as well as thousands of abandoned wells and pits. In the Allegheny Reservoir itself, divers spotted 20 of 81 known improperly plugged or unplugged wells, 7 of which were leaking oily high-chloride produced water into the reservoir and have since been plugged. EPA is concerned that many others are also leaking native oily produced water.

The Coast Guard (USCG) surveyed the forest for oil spills and produced water discharges, identifying those of particular danger to be cleaned immediately, by government if necessary. In the Allegheny Forest alone, USCG identified over 500 sites where oil was leaking from wells, pits, pipelines, or storage tanks. In 59 cases, oil was being discharged directly into streams; 217 sites showed evidence of past discharges and were on the verge of discharging again into the Allegheny Reservoir. Illegal disposal of oil field wastes has had a detrimental effect on the environment: "...there has been a lethal effect on trout streams and damage to timber and habitat for deer, bear and grouse." On Lewis Run, 52 discharge sites have been identified and the stream supports little aquatic life. Almost all streams in the Allegheny Forest have suppressed fish population as a "...direct result of pollution from oil and gas activity." (API notes that oil and produced water leaks into streams are prohibited by State and Federal regulations.)[15] (PA 09)[16]

These leaks are prohibited by State and Federal regulations. However, discharges are allowed, by permit, under the NPDES program.

Damage to Water Wells from Oil or Gas Well Drilling and Fracturing

In West Virginia, the minimum distance established for separating oil or gas wells from drinking water wells is 200 feet. Siting of oil or gas drill sites near domestic water wells is not uncommon.[17] West Virginia has no automatic provision requiring drillers to replace water wells lost in this way; owners must replace them at their own expense

[15] Comments in the docket by API pertain to PA 09. API states that "...litigation is currently pending with respect to this case in which questions have been raised about the factual basis for government action in this case."

[16] References for case cited: U.S. Geological Survey letter from Buckwalter to Rice concerning sampling of water in northern Pennsylvania, 10/27/86. Pennsylvania Department of Environmental Resources press release on analysis of water samples, undated but after 8/83. Oil and Water: When One of the By products of High-grade Oil Production is a Low-grade Allegheny National Forest, It's Time to Take a Hard Look at Our Priorities, by Jim Morrison, Pennsylvania Wildlife, Vol. 8, No. 1. Pittsburgh Press, "Spoiling a Wilderness," 1/22/84; "Oil Leaking into Streams at 300 Sites in Northwestern Area of the State," 1985. Warren Times, "Slick Issues Underscore Oil Cleanup in National Forest," 1986.

[17] According to members of the Legal Aid Society of Charleston, West Virginia, landowners have little control over where oil and gas wells are sited. Although a provision exists for hearings to be held to question the siting of an oil or gas well, this process is rarely used by private landowners for economic and other reasons.

or sue the driller. Where there is contamination of a freshwater source, State regulations presume an oil or gas drilling site is responsible if one is located within 1,000 feet of the water source.

During the fracturing process, fractures can be produced, allowing migration of native brine, fracturing fluid, and hydrocarbons from the oil or gas well to a nearby water well. When this happens, the water well can be permanently damaged and a new well must be drilled or an alternative source of drinking water found.

In 1982, Kaiser Gas Co. drilled a gas well on the property of Mr. James Parsons. The well was fractured using a typical fracturing fluid or gel. The residual fracturing fluid migrated into Mr. Parson's water well (which was drilled to a depth of 416 feet), according to an analysis by the West Virginia Environmental Health Services Lab of well water samples taken from the property. Dark and light gelatinous material (fracturing fluid) was found, along with white fibers. (The gas well is located less than 1,000 feet from the water well.) The chief of the laboratory advised that the water well was contaminated and unfit for domestic use, and that an alternative source of domestic water had to be found. Analysis showed the water to contain high levels of fluoride, sodium, iron, and manganese. The water, according to DNR officials, had a hydrocarbon odor, indicating the presence of gas. To date Mr. Parsons has not resumed use of the well as a domestic water source. (API states that this damage resulted from a malfunction of the fracturing process. If the fractures are not limited to the producing formation, the oil and gas are lost from the reservoir and are unrecoverable.)[18] (WV 17)[19]

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[18] Comments in the Docket pertain to WV 17, by David Flannery and West Virginia Department of Energy. Mr. Flannery states that "...this is an area where water problems have been known to occur independent of oil and gas operations." EPA believes that the "problems" Mr. Flannery is referring to are the natural high level of fluoride, alkalinity, sodium, and total dissolved solids in the water. However, the constituents of concern found in this water well were the gelatinous material associated with the fracturing process, and hydrocarbons. West Virginia Department of Energy states that the WVDOE "...had no knowledge that the Pittsburg sand was a fresh water source." Also, WVDOE pointed out that WV Code 22B-1-20 "...requires an operator to cement a string of casing 30 feet below all fresh water zones." According to case study records, Kaiser Gas Co. did install a cement string of casing 30 feet below the Pittsburg sand, from which Mr. Parson drew his water.

[19] References for case cited: Three lab reports containing analysis of water well. Letter from J. E. Rosencrance, Environmental Health Services Lab, to P. R. Merritt, Sanitarian, Jackson County, West Virginia. Letter from P. R. Merritt to J. E. Rosencrance requesting analysis. Letter from M. W. Lewis, Office of Oil and Gas, to James Parsons stating State cannot help in recovering expenses, and Mr. Parsons must file civil suit to recover damages. Water well inspection report - complaint. Sample report forms.

There were no violations of West Virginia regulations in this case.

Damage cases involving drilling activity in proximity to residential areas are known to have occurred in Pennsylvania:

Civil suit was brought by 14 families living in the village of Belmar against a Meadville-based oil drilling company, Norwesco Development Corporation, in June 1986. Norwesco had drilled more than 200 wells near Belmar, and residents of the village claimed that the activity had contaminated the ground water from which they drew their domestic water supply. The Pennsylvania Department of Environmental Resources and the Pennsylvania Fish Commission cited Norwesco at least 19 times for violations of State regulations. Norwesco claimed it was not responsible for contamination of the ground water used by the village of Belmar. Norwesco suggested instead that the contamination was from old, long-abandoned wells. The Pennsylvania Department of Environmental Resources (DER) agreed with Belmar residents that the contamination was from the current drilling operations. Ground water in Belmar had been pristine prior to the drilling operation of Norwesco. All families relying on the ground water lost their domestic water supply. The water from the contaminated wells would "...burn your eyes in the shower, and your skin is so dry and itchy when you get out." Families had to buy bottled water for drinking and had to drive, in some cases, as far as 30 miles to bathe. Not only were residents not able to drink or bathe using the ground water; they could not use the water for washing clothes or household items without causing permanent stains. Plumbing fixtures were pitted by the high level of total dissolved solids and high chloride levels.

In early 1986, DER ordered Norwesco to provide Belmar with an alternative water supply that was equal in quality and quantity to what the Belmar residents lost when their wells were contaminated. In November 1986 Norwesco offered a cash settlement of $275,000 to construct a new water system for the village and provided a temporary water supply. (PA 08)[20]

This case represents a violation of Pennsylvania regulations.

Problems with Landspreading in West Virginia

Landspreading of drilling muds containing up to 25,000 ppm chlorides was allowed in West Virginia until November 1, 1987. The new limit is 12,500 ppm chlorides. These concentrations of chlorides are considerably

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20 References for case cited: Pittsburgh Press, "Franklin County Village Sees Hope after Bad Water Ordeal," 12/7/86. Morning News, "Oil Drilling Firm Must Supply Water to Homes," 1/7/86; "Village Residents Sue Drilling Company," 6/7/86.

higher than concentrations permitted for landspreading in other States and are several times higher than native vegetation can tolerate. Landspreading of these high-chloride muds may result in damage to arable land. This waste drilling mud may kill surface vegetation where the mud is directly applied; salts in the wastes can leach into surrounding soil, affecting larger plants and trees. Leaching of chlorides into shallow ground water is also a potential problem associated with this practice.

> In early 1986 Tower Drilling land-applied the contents of a reserve pit to an area 100 feet by 150 feet. All vegetation died in the area where pit contents were directly applied, and three trees adjacent to the land application area were dying allegedly because of the leaching of high levels of chlorides into the soil. A complaint was made by a private citizen to the West Virginia DNR. Samples taken by West Virginia DNR of the contaminated soil measured 18,000 ppm chlorides.[21](WV 13)[22]

Land applying reserve pit contents with more than 12,500 ppm chlorides is now in violation of West Virginia regulations.

Problems with Enhanced Oil Recovery (EOR) and Abandoned Wells in Kentucky

The Martha Oil Field, located in northeastern Kentucky, is situated on the border of Lawrence and Johnson counties and occupies an area in excess of 50 square miles. Oil production began in the early 1920s and secondary recovery operations or waterflooding commenced in 1955. Ashland Exploration, Inc., operated UIC-permitted injection wells in the area. Approximately 8,500 barrels of fresh water were being injected per day at an average pressure of 700 pounds per square inch.

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[21] Comments in the Docket by David Flannery and API pertain to WV 13. The statements by API and Mr. Flannery are identical. They state that it might not be "...possible to determine whether it was the chloride concentration alone which caused the vegetation stress." Also, they claim that the damage was short term and "...full recovery of vegetation was made." Neither commenter submitted supporting documentation.

[22] References for case cited: West Virginia Department of Natural Resources complaint form #6/131/86. Analytical report on soil analysis of kill area.

Several field investigations were conducted by the U.S. Environmental Protection Agency, Region IV, to appraise the potential for and extent of contamination of ground-water resources. Field inspections revealed widespread contamination of underground sources of drinking water (USDWs).

From April 29 through May 8, 1986, representatives of the U.S. EPA, Region IV, conducted a surface water investigation in the Blaine Creek watershed near Martha, Kentucky. The study was requested by the U.S. EPA Water Management Division to provide additional baseline information on stream water quality conditions in the Blaine Creek area. Blaine Creek and its tributaries have been severely impacted by oil production activities conducted in the Martha field since the early 1900s. The Water Management Division issued an administrative order requiring that waterflooding of the oil-bearing strata cease by February 4, 1986, and also requiring that direct or indirect brine discharges to area streams cease by May 7, 1986.

For the study in 1986, 27 water chemistry sampling stations, 13 of which were also biological sampling stations, were established in the Blaine Creek watershed. Five streams in the study area were considered control stations. Biological sampling indicated that macroinvertebrates in the immediate Martha oil field area were severely impacted. Many species were reduced or absent at all stations within the oil field. Blaine Creek stations downstream of the oil field, although impacted, showed gradual improvement in the benthic macroinvertebrates. Control stations exhibited the greatest diversity of benthic macroinvertebrate species. Water chemistry results for chlorides generally indicated elevated levels in the Martha oil field drainage area. Chloride values in the affected area of the oil field ranged from 440 to 5,900 mg/L. Control station chloride values ranged from 3 to 42 mg/L.

In May of 1987, EPA, Region IV, conducted another surface water investigation of the Blaine Creek watershed. The study was designed to document changes in water quality in the watershed 1 year following the cessation of oil production activities in the Martha oil field. By May of 1987, the major operator in the area, Ashland Exploration, Inc., had ceased operations. Some independently owned production wells were still in service at this time. Chloride levels, conductivity, and total dissolved solids levels had significantly decreased at study stations within the Martha oil field. Marked improvements were observed in the benthic invertebrate community structures at stations within the Martha field. New species that are considered sensitive to water quality conditions were present in 1987 at most of the biological sampling stations, indicating that significant water quality improvements had occurred following cessation of oil production activities in the Martha field. Chloride levels in one stream in the Blaine Creek watershed decreased from 5,900 mg/L to 150 mg/L.[23]

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[23] References for case cited: Martha Oil Field Water Quality Study, Martha, Kentucky, U.S. EPA, Athens, Georgia, May 1986. Martha Oil Field Water Quality Study, Martha, Kentucky, U.S. EPA, Athens, Georgia, May 1987.

In response to EPA's notice of violations and other requirements, Ashland proposed to EPA that it would properly plug and abandon all existing injection wells, oil production wells, and water-supply wells and most gas production wells in the Martha field. EPA, Region IV, issued to Ashland an Order on Consent With Administrative Civil Penalty under the authority of Section 1423(9)(2) of the SDWA. Ashland has paid an administrative penalty of $125,000 and will plug and abandon approximately 1,433 wells in compliance with EPA standards. If warranted, Ashland will provide alternative water supplies to private water well users whose supplies have been adversely affected by oil production activities.

SOUTHEAST

The Southeast zone includes North Carolina, South Carolina, and Georgia. There is little oil and gas activity in this zone. No field research was conducted to collect damage cases in this zone.

GULF

The Gulf zone includes Arkansas, Louisiana, Mississippi, Alabama, and Florida. Attention in the damage case effort was focused on Arkansas and Louisiana, the two major producers of the zone.

Operations

Operations in Arkansas are predominantly small to mid-sized operations in mature production areas. A significant percentage of production in this area comes from stripper wells, which produce large volumes of associated produced water containing high levels of chlorides. For Arkansas, most production occurs in the southern portion of the State.

The average depth of a new well drilled in Arkansas in 1985 was 4,148 feet. That year 121 exploratory wells were drilled and 1,055 new wells were completed.

Louisiana has two distinct production areas. The northern half of the State is dominated by marginal stripper production from shallow wells in mature fields. The southern half of Louisiana has experienced most of the State's development activity in the last decade. There has been heavy, capital-intensive development of the Gulf Coast area, where gas is the principal product. Wells tend to be of medium depth; operations are typically located in or near coastal wetland areas on barge platforms or small coastal islands. Operators dredge canals and estuaries to gain access to sites.

In this area, reserve pits are constructed out of the materials found on coastal islands, mainly from peat, which is highly permeable and susceptible to damage after exposure to reserve pit fluids. Reserve pits on barges are self-contained, but are allowed to be discharged in particular areas if levels of certain constituents in wastes are below specified limits. If certain constituents are found in concentrations above these limits in the waste, they must be injected or stored in pits (unlined) on coastal islands.

For many operators in the Gulf Coast area, produced water is discharged directly to adjacent water bodies. Fields in this region have an average water/oil ratio of from 4:1 to 6:1. The Louisiana Department of Environmental Quality (DEQ) is now requiring that operators apply for permits for these discharges. At this writing, the Louisiana DEQ had received permit applications for approximately 750 to 800 discharge points. Results of field work done by the Louisiana DEQ, the Louisiana Geological Survey, and the Louisiana University Marine Consortium show that roughly 1.8 to 2.0 million barrels of produced water are discharged daily in this area. According to the Louisiana Geological Survey, many receiving water bodies contain fresh water, with some receiving water bodies 70 times fresher than the oil field discharges. The U.S. Fish and Wildlife Service has stated that it will aggressively oppose any permits for produced water discharges in the Louisiana wetlands of the Gulf Coast.

The average depth of a new well drilled in northern Louisiana in 1985 was 2,713 feet; along the Gulf Coast it was 10,150 feet. In the northern part of the State, 244 exploratory wells were drilled and 4,033 production wells were completed. In the southern part of the State, 215 exploratory wells were drilled and 1,414 production wells were completed.

Types of Operators

In Arkansas, operators are generally small to mid-sized independents, including some established operators and others new to the industry. Because production comes mostly from stripper wells, operators tend to be vulnerable to market fluctuations.

Northern Louisiana's operators, like those in Arkansas, tend to be small to mid-sized independents. They share the same economic vulnerabilities with their neighbors in Arkansas. In addition, however, Louisiana's more marginal operations may be particularly stressed by the new Rule 29B, which requires the closing out and elimination of all current and future onsite produced water disposal pits by 1989. Estimated closing costs per pit are $20,000.

Operators in southern Louisiana tend to be major companies and large independents. They are less susceptible to fluctuating market conditions in the short term. Projects in the south tend to be larger than those in the north and are located in more environmentally sensitive areas.

Major Issues

Ground-Water Contamination from Unlined Produced Water Disposal Pits and Reserve Pits

Unlined produced water disposal pits have been used in Louisiana for many years and are only now being phased out under Rule 29B. Past practice has, however, resulted in damages to ground water and danger to human health.

In 1982, suit was brought on behalf of Dudley Romero et al. against operators of an oil waste commercial disposal facility, PAB Oil Co. The plaintiffs stated that their domestic water wells were contaminated by wastes dumped into open pits in the PAB Oil Co. facility which were alleged to have migrated into the ground water, rendering the water wells unusable. Oil field wastes are dumped into the waste pits for skimming and separation of oil. The pits are unlined. The PAB facility was operating prior to Louisiana's first commercial oil field waste facility regulations. After promulgation of new regulations, the facility continued to operate for 2 years in violation of the new regulations, after which time the State shut down the facility.

The plaintiff's water wells are downgradient of the facility, drilled to depths of 300 to 500 feet. Problems with water wells date from 1979. Extensive analysis was performed by Soil Testing Engineers, Inc., and U.S. EPA, on the plaintiff's water wells adjacent to the site to determine the probability of the well contamination coming from the PAB Oil Co. site. There was also analysis on surface soil contamination. Soil Testing

Engineers, Inc., determined that it was possible for the wastes in the PAB Oil Co. pits to reach and contaminate the Romeros' water wells. Surface sampling around the perimeter of the PAB Oil Co. site found high concentrations of metals. Resistivity testing showed that plumes of chloride contamination in the water table lead from the pits to the water wells. Borings that determined the substrata makeup suggested that it would be possible for wastes to contaminate the Romero ground water within the time that the facility had been in operation if the integrity of the clay cap in the pit had been lost (as by deep excavation somewhere within it). The pit was 12 feet deep and within range to percolate into the water-bearing sandy soil.

The plaintiffs complained of sickness, nausea, and dizziness, and a loss of cattle. The case was settled out of court. The plaintiffs received $140,000 from PAB Oil Co. (LA 67)[24]

Unlined commercial disposal pits are now illegal in Louisiana.

The ground in this area is highly permeable, allowing pit contents to leach into soil and ground water. Waste constituents potentially leaching into ground water from unlined pits include arsenic, cadmium, chromium, copper, lead, nickel, zinc, and chlorides. There have been incidents illustrating the permeability of subsurface formations in this area.[25]

Allowable Discharge of Drilling Mud into Gulf Coast Estuaries

Under existing Louisiana regulations, drilling muds from onshore operations may be discharged into estuaries of the Gulf of Mexico. The State issues permits for this practice on a case-by-case basis. These

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24 References for case cited: Soil Testing Engineers, Inc., Brine Study, Romero, et al., Abbeville, Louisiana, 10/19/82. U.S. EPA lab analysis of pits and wells, 10/22/81. Dateline, Louisiana: Fighting Chemical Dumping, by Jason Berry, May-June, 1983.

25 A gas well operated by Conoco, which had been plugged and abandoned, blew out below the surface from December 11, 1985, to January 9, 1986. The blowout sent gas through fault zones and permeable formations to the land surface owned by Claude H. Gooch. The gas could be ignited by a match held to the ground. The gas was also determined to be a potential hazard to drinking water wells in the immediate area.

estuaries are often valuable commercial fishing grounds. Since the muds can contain high levels of toxic metals, the possibility of bioaccumulation of these metals in shellfish or finfish is of concern to EPA.

In 1984, the Glendale Drilling Co., under contract to Woods Petroleum, was drilling from a barge at the intersection of Taylor's Bayou and Cross Bayou. The operation was discharging drill cuttings and mud into the bayou within 1,300 feet of an active oyster harvesting area and State oyster seeding area. At the time of discharge, oyster harvests were in progress. (It is State policy in Louisiana not to grant permits for the discharge of drill cuttings within 1,300 feet of an active oyster harvesting area. The Louisiana Department of Environmental Quality does not allow discharge of whole mud into estuaries.)

A State Water Pollution Control Division inspector noted that there were two separate discharges occurring from the barge and a low mound of mud was protruding from the surface of the water beneath one of the discharges. Woods Petroleum had a letter from the Louisiana Department of Environmental Quality authorizing them to discharge the drill cuttings and associated mud, but this permit would presumably not have been issued if it had been known that the drilling would occur near an oyster harvesting area. While no damage was noted at time of inspection, there was great concern expressed by the Louisiana Oyster Growers Association, the Louisiana Department of Wildlife and Fisheries, Seafood Division, and some parts of the Department of Water Pollution Control Division of the Department of Environmental Quality. The concern of these groups stemmed from the possibility that the discharge of muds and cuttings with high content of metals may have long-term impact on the adjacent commercial oyster fields and the State oyster seed fields in nearby Junop Bay. In such a situation, metals can precipitate from the discharge, settling in progressively higher concentrations in the bayou sediments where the oysters mature. The bioaccumulation of these metals by the oysters can have an adverse impact on the oyster population and could also lead to human health problems if contaminated oysters are consumed.

The Department of Environmental Quality decided in this case to direct the oil company to stop the discharge of drill cuttings and muds into the bayou. In this instance, the Department of Environmental Quality ordered that a drill cutting barge be used to contain the remainder of the drill cuttings. The company was not ordered to clean up the mound of drill cuttings that it had already deposited in the bayou. (LA 20)[26]

Activities in this case, though allowed by the State, are illegal according to State law.

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[26] References for case cited: Louisiana Department of Environmental Quality, Water Pollution Control Division, Office of Water Resources, internal memorandum, 6/3/85.

Illegal Disposal of Oil Field Waste in the Louisiana Gulf Coast Area

The majority of damage cases collected in Louisiana involve illegal disposal or inadequate facilities for containment of wastes generated by operations on the Gulf Coast. For example:

> Two Louisiana Water Pollution Control inspectors surveyed a swamp adjacent to a KEDCO Oil Co. facility to assess flora damage recorded on a Notice of Violation issued to KEDCO on 3/13/81. The Notice of Violation discussed produced water discharges into an adjacent canal that emptied into a cypress swamp from a pipe protruding from the pit levee. Analysis of a sample collected by a Mr. Martin, the complainant, who expressed concern over the high-chloride produced water discharge into the canal he used to obtain water for his crawfish pond, showed salinity levels of 32,000 ppm (seawater is 35,000 ppm).
>
> On April 15, 1981, the Water Pollution Control inspectors made an effort to measure the extent of damage to the trees in the cypress swamp. After surveying the size of the swamp, they randomly selected a compass bearing and surveyed a transect measuring 200 feet by 20 feet through the swamp. They counted and then classified all trees in the area according to the degree of damage they had sustained. Inspectors found that "...an approximate total area of 4,088 acres of swamp was severely damaged." Within the randomly selected transect, they classified all trees according to the degree of damage. Out of a total of 105 trees, 73 percent were dead, 18 percent were stressed, and 9 percent were normal. The inspectors' report noted that although the transect ran through a heavily damaged area, there were other areas much more severely impacted. They therefore concluded, based upon data collected and firsthand observation, that the percentages of damaged trees recorded "...are a representative, if not conservative, estimate of damage over the entire affected area." In the opinion of the inspectors, the discharge of produced water had been occurring for some time, judging by the amount of damage sustained by the trees. KEDCO was fined $9,500 by the State of Louisiana and paid $4,500 in damages to the owner of the affected crawfish farm. (LA 45)[27]

This discharge was in violation of Louisiana regulations.

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[27] References for case cited: Louisiana Department of Natural Resources, Water Pollution Control Division, internal memo, Cormier and St. Pe to Givens, concerning damage evaluation of swamp near the KEDCO Oil Co. facility 6/24/81. Notice of Violation, Water Pollution Control Log #2-8-81-21.

Most of the damage cases collected involved small operations run by independent companies. Some incidents, however, involved major oil companies:

Sun Oil Co. operates a site located in the Chacahoula Field. A Department of Natural Resources inspector noted a site configuration during an inspection (6/25/82) of a tank battery surrounded by a pit levee and a pit (30 yards by 50 yards). The pit was discharging produced water into the adjacent swamp in two places, over a low part in the levee and from a pipe that had been put through the ring levee draining directly into the swamp. Produced water, oil, and grease were being discharged into the swamp. Chloride concentrations from samples taken by the inspectors ranged from 2,948 to 4,848 ppm, and oil and grease concentrations measured 12.6 to 26.7 ppm. The inspector noted that the discharge into the swamp was the means by which the company drains the tank battery ring levee area. A notice of violation was issued to Sun Oil by the Department of Natural Resources. (LA 15)[28]

This discharge was in violation of Louisiana regulations.

Some documented cases noted damage to agricultural crops:

Dr. Wilma Subra documented damage to D.T. Caffery's sugar cane fields adjacent to a production site, which included a saltwater disposal well, in St. Mary Parish., The operator was Sun Oil. The documentation was collected between July of 1985 and November of 1986 and included reports of salt concentrations in soil at various locations in the sugar cane fields, along with descriptions of accompanying damage. Dr. Subra noted that the sugar cane fields had various areas that were barren and contained what appeared to be sludge. The production facility is upgradient from the sugar cane fields, and Dr. Subra surmised that produced water was discharged onto the soil surface from the facility and that a plume of salt contamination spread downgradient, thereby affecting 7.3 acres of sugar cane fields, over a period of a year and a half.

In July 1985, Dr. Subra noted that the cane field, though in bad condition, was predominantly covered with sugar cane. There were, however, weeds or barren soil covering a portion of the site. The patch of weeds and barren soil matched the area of highest salt concentration. In the area where the topography suggested that brine concentrations would be lowest, the sugar cane appeared healthy. Subsequent field investigation and soil sampling conducted by Dr. Subra in November of 1986 found the field to be nearly barren, with practically no sugar cane growing.

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28 References for case cited: Louisiana Department of Natural Resources, Water Pollution Control Division, internal memo from Cormier to Givens, 8/16/82, concerning Sun Oil Co. brine discharge, Chacahoula Field. Log #2-8-81-122. Lab analysis, 7/2/82.

Dr. Subra measured concentrations of salts in the soil ranging from a low of 1,403 ppm to 35,265 ppm at the edge of the field adjacent to the oil operation. Sun has undertaken a reclamation project to restore the land. It is estimated that the project will take 2 to 3 years to complete. In the interim, Sun Oil Co. will pay the sugar cane farmer for loss of crops.[29] (LA 63)[30]

The State of Louisiana has not taken any enforcement action in this case; it is unclear whether any State regulations were violated.

Most damage associated with illegal disposal involves disposal of produced water containing high levels of chloride (brine). Illegal disposal of other types of oil field waste also result in environmental damage:

Chevco-Kengo Services, Inc. operates a centralized disposal facility near Abbeville, Louisiana. Produced water and other wastes are transported from surrounding production fields by vacuum truck to the facility. Complaints were filed by private citizens alleging that discharges from the facility were damaging crops of rice and crawfish, and that the facility represented a threat to the health of nearby residents. An inspection of the site by the Water Pollution Control Division of the Department of Natural Resources found that a truck washout pit was emptying oil field wastes into a roadside ditch flowing into nearby coulees.

Civil suit was brought by private citizens against Chevco-Kengo Services, Inc., asking for a total of $4 million in property damages, past and future crop loss, and exemplary damages. Lab analysis performed by the Department of Natural Resources of waste samples indicated high metals content of the wastes, especially in samples taken from the area near the facility and in the adjacent rice fields, indicating that the discharge of wastes from the facility was the source of damage to the surrounding land. The case is in litigation.[31] (LA90)[32]

The State did not issue a notice of violation in this case. However, this type of discharge is illegal.

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29 API states that an accidental release occurred in this case. EPA records show this release lasted 2 years.

30 References for case cited: Documentation from Dr. Wilma Subra, including a series of maps documenting changes in the sugar cane over a period of time, 12/86. Maps showing location of sampling and salt concentrations.

31 API states that these discharges were accidental.

32 References for case cited: Louisiana Department of Natural Resources, Water Pollution Control Division, internal memo, lab analysis, and photographs, 8/25/83. Letter from Westland Oil Development Corp. to Louisiana Department of Natural Resources, 4/15/83.

Illegal Disposal of Oil Field Waste in Arkansas

The majority of damage cases found in Arkansas relate to illegal dumping of produced water and oily waste from production units. Damages typically include pollution of surface streams and contamination of soil with high levels of chlorides and oil, documented or potential contamination of ground water with elevated levels of chlorides, and damage to vegetation (especially forest and timberland), from exposure to high levels of chlorides.

An oil production unit operated by Mr. J. C. Langley was discharging oil and produced water in large quantities onto the property of Mr. Melvin Dunn and Mr. W. C. Shaw. The oil and produced water discharge allegedly caused severe damage to the property, interfered with livestock on the property, and delayed construction of a planned lake. Mr. Dunn had spoken repeatedly with a company representative operating the facility concerning the oil and produced water discharge, but no changes occurred in the operation of the facility. A complaint was made to Arkansas Department of Pollution Control and Ecology (ADPCE), the operator was informed of the situation, and the facility was brought into compliance. Mr. Dunn then hired a private attorney in order that remedial action be taken. It is not known whether the operator cleaned up the damaged property.[33] (AR 07)[34]

This discharge was in violation of Arkansas regulations.

On September 20, 1984, an anonymous complaint was filed with ADPCE concerning the discharge of oil and produced water in and near Smackover Creek from production units operated by J. S. Beebe Oil Account. Upon investigation by ADPCE, it was found that saltwater was leaking from a salt water disposal well located on the site. Mr. Beebe wrote a letter stating his willingness to correct the situation. On November 16, 1984, the site was again investigated by ADPCE, and it was found that pits on location were being used as the primary disposal facility and were

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33 API states that this incident constituted a spill and is therefore a non-RCRA issue.

34 References for case cited: Arkansas Department of Pollution Control and Ecology (ADPCE) Complaint form, #EL 1721, 5/14/84. Letter from Michael Landers, attorney to Mr. Dunn, requesting investigation from Wayne Thomas concerning Langley violations. Letter from J. C. Langley to Wayne Thomas, ADPCE, denying responsibility for damages of Dunn and Shaw property, 6/5/84. Certified letter from Wayne Thomas to J. C. Langley discussing violations of facility and required remedial actions, 5/30/87. Map of violation area, 5/29/84. ADPCE oil field waste survey documenting unreported oil spill on Langley unit, 5/25/84. Letter from Michael Landers, attorney to ADPCE, discussing damage to property of Dunn and Shaw, 5/11/84.

overflowing and leaking into Smackover Creek. The ADPCE issued a Notice of Violation (LIS 84-066) and noted that the pits were below the creek level and overflowed into the creek when heavy rains occurred. One pit was being siphoned over the pit wall, while waste from another pit was flowing onto the ground through an open pipe. The floors and walls of the pits were saturated, allowing seepage of waste from the pits. ADPCE ordered Mr. Beebe to shut down production and clean up the site and fined him $10,500. (AR 10)[35]

These discharges were occurring in violation of Arkansas regulations.

The State of Arkansas has limited resources for inspecting disposal facilities associated with oil and gas production. (See Table VII-7.) Furthermore, the two State agencies responsible for regulating oil and gas operations (the Arkansas Oil and Gas Commission (OGC) and the Arkansas Department of Pollution Control and Ecology (ADPCE)) have overlapping jurisdictions. In the next case, the landowner is the Arkansas Game and Fish Commission, which attempted to enforce a permit it issued to the operator for drilling activity on the Commission's land. As of summer 1987, no permit had been issued by either the OGC or the ADPCE.

In 1983 and again in 1985, James M. Roberson, an oil and gas operator, was given surface access by the Arkansas Game and Fish Commission for drilling in areas in the Sulphur River Wildlife Management Area (SRWMA), but was not issued a drilling permit by either of the State agencies that share jurisdiction over oil and gas operations. Surface rights are owned by the Arkansas Game and Fish Commission. The Commission attempted to write its own permits for this operation to protect the wildlife management area resources. Mr. Roberson repeatedly violated the requirements contained in these surface use permits, and the Commission also determined that he was in violation of general State and Federal regulations applicable to his operation in the absence of OGC or ADPCE permits. These violations led to release of oil and high-chloride produced water into the wetland areas of the Sulphur River and Mercer Bayou from a leaking saltwater disposal well and illegal produced water disposal pits maintained by the operator.

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35 References for case cited: ADPCE complaint form #EL 1792, 9/20/84, and 8/23/84. ADPCE inspection report, 9/5/84. Letter from ADPCE to J. S. Beebe outlining first run of violations, 9/6/84. Letter stating willingness to cooperate from Beebe to ADPCE, 9/14/84. ADPCE complaint form #EL 1789, 9/19/84. ADPCE inspection report, 9/25 and 9/26/84. ADPCE complaint form #EL 1822, 11/16/84. ADPCE Notice of Violation, Findings of Fact, Proposed Order and Civil Penalty Assessment, 11/21/84. Map of area. Miscellaneous letters.

Oil and saltwater damage to the area was documented in a study conducted by Hugh A. Johnson, Ph.D., a professor of biology at Southern Arkansas University. His study mapped chloride levels around each well site and calculated the affected area. The highest chloride level recorded in the wetland was 9,000 ppm (native vegetation begins to be stressed from exposure to 250 ppm chlorides). He found that significant areas around each well site had dead or stressed vegetation related to excessive chloride exposure. The Game and Fish Commission fears that continued discharges of produced water and oil in this area will threaten the last remaining forest land in the Red River bottoms.[36] (AR 04)[37]

These discharges were in violation of State and Federal regulations.

Jurisdiction in the above case is unclear. Under a 1981 amendment to the State Oil and Gas Act, OGC was granted formal permit authority over oil and gas operations, but this authority is to be shared in certain situations with the ADPCE. Jurisdiction is to be shared where Underground Injection Control (UIC) wells are concerned, but is not clearly defined with respect to construction or management of reserve pits or disposal of drilling wastes. ADPCE has made attempts to clarify the situation by issuing informal letters of authorization to operators, but these are not universally recognized throughout the State. (A full discussion of this issue can be found in Chapter VII and in Appendix A.)

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[36] API states that the Arkansas Water and Air Pollution Act gives authority at several levels to require cleanup of these illegal activities and to prevent further occurrences. EPA believes that even though State and Federal Laws exist which prohibit this type of activity, no mechanism for enforcement is in place.

[37] References for case cited: Letter from Steve Forsythe, Department of the Interior (DOI), to Pat Stevens, Army Corps of Engineers (ACE), stating that activities of Mr. Roberson have resulted in significant adverse environmental impacts and disruptions and that DOI recommends remedial action be taken. Chloride Analysis of Soil and Water Samples of Selected Sites in Miller County, Arkansas, by Hugh A. Johnson, Ph.D., 10/22/85. Letter to Pat Stevens, ACE, from Dick Whittington, EPA, discussing damages caused by Jimmy Roberson in Sulphur River Wildlife Management Area (SRWMA) and recommending remedial action and denial of new permit application. Oil and Gas well drilling permits dated 1983 and 1985 for Roberson activities. A number of letters and complaints addressing problems in SRWMA resulting from activities of James Roberson. Photographs. Maps.

Improperly Operated Injection Wells

Improper operation of injection wells raises the potential for long-term damage to ground-water supplies, as the following case from Arkansas illustrates.

> On September 19, 1984, Mr. James Tribble made a complaint to the Arkansas Department of Pollution Control and Ecology concerning salt water that was coming up out of the ground in his yard, killing his grass and threatening his water well. There are many oil wells in the area, and water flooding is a common enhanced recovery method at these sites. Upon inspection of the wells nearest to his residence, it was discovered that the operator, J. C. McLain, was injecting salt water into an unpermitted well. The salt water was being injected into the casing, or annulus, not into tubing. Injection into the unsound casing allegedly allowed migration into the freshwater zone. A produced water pit at the same site was near overflowing. State inspectors later noted in a followup inspection that the violations had been corrected. No fine was levied. (AR 12) [38]

Operation of this well would now be in violation of UIC requirements.

MIDWEST

The Midwest zone includes the States of Michigan, Iowa, Indiana, Wisconsin, Illinois, and Missouri. Damage cases were collected in Michigan.

Operations

Michigan produces both oil and gas from limestone reef formations at sites scattered throughout the State at a depth of 4,000 to 6,000 feet.

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[38] References for case cited: ADPCE Complaint form, #EL 1790, 9/19/84. ADPCE inspection report, 9/20/84. Letter from ADPCE to Mr. J. C. McLain describing violations and required corrective action, 9/21/84. ADPCE reinspection report, 10/11/84.

Oil and gas development is relatively new in this area, and most production is primary (that is, as yet it involves no enhanced or secondary recovery methods, such as water flooding). Exploration in Michigan is possibly the most intense currently under way anywhere in the country. The average depth of new wells drilled in 1985 was 4,799 feet. In that year 863 wells were completed, of which 441 were exploration wells.

Types of Operators

Operators in Michigan include everything from small independent companies to the major oil companies.

Major Issues

Ground-Water Contamination in Michigan

All the damage cases gathered in Michigan are based on case studies written by the Michigan Geological Survey, which regulates oil and gas operations in the State. All of these cases deal with ground water contamination with chlorides. While the State has documented that damages have occurred in all cases, sources of damages are not always evident. Usually, several potential sources of contamination are listed for each case, and the plume of contamination is defined by using monitoring wells. Most of the cases involve disposal of produced waters.

> In June 1983, a water well owned by Mrs. Geneva Brown was tested after she had filed a complaint to the Michigan Geological Survey. After responding, the Michigan Geological Survey found a chloride concentration of 490 ppm in the water. Subsequent sampling from the water well of a neighbor, Mrs. Dodder, showed that her well measured 760 ppm chloride in August. There are a total of 15 oil and gas wells in the area surrounding the contaminated water wells. Only five of the wells are still producing, recovering a combination of oil and produced water. The source of the pollution was evidently the H. E. Trope, Inc., crude oil separating facilities and brine storage tanks located upgradient from the contaminated water wells. Monitoring wells were installed to confirm the source of the contamination. Stiff diagrams were used to confirm the similarity of the constituents of the formation brine and the chloride contamination of the

affected water wells. Sample results located two plumes of chloride contamination ranging in concentration from 550 to 1,800 ppm that are traveling in a southeasterly direction downgradient from the produced water storage tanks and crude oil separator facilities owned by H.E. Trope. (MI 05)[39]

Produced water spills from production facilities are covered by Michigan regulations.

Ground-water contamination in the State has also been caused by injection wells, as illustrated by the following case:

In April 1980, residents of Green Ridge Subdivision, located in Section 15, Laketon Township, Muskegon County, complained of bad-tasting water from their domestic water wells. Some wells sampled by the local health department revealed elevated chloride concentrations. Because of the proximity of the Laketon Oil Field, an investigation was started by the Michigan Geological Survey. The Laketon Oil Field consists of dry holes, producing oil wells, and a produced water disposal well, the Harris Oil Corp. Lappo #1. Oil wells produce a mixture of oil and produced water. The produced water is separated and disposed of by gravity in the produced water disposal well and is then placed back in the producing formation. After reviewing monitoring well and electrical resistivity survey data, the Michigan Geological Survey concluded that the source of the contamination was the Harris Oil Corp. Lappo #1 produced water disposal well, which was being operated in violation of UIC regulations. (MI 06)[40]

This disposal well was being operated in violation of State regulations.

Damage to ground water under a drill site can occur even where operators take special precautions for drilling near residential areas. An example follows:

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[39] References for case cited: Open file report, Michigan Department of Natural Resources, Investigation of Salt-Contaminated Groundwater in Cat Creek Oil Field, Hersey Township, conducted by D. W. Forstat, 1984. Appendix includes correspondence relating to investigation, area water well drilling logs, Stiff diagrams and water analysis, site monitor well drilling logs, and water sample analysis for samples used in the investigation.

[40] References for case cited: Open file report, Michigan Department of Natural Resources, Investigation of Salt-Contaminated Groundwater in Green Ridge Subdivision, Laketon Township, conducted by B. P. Shirey, 1980. Appendix includes correspondence relating to investigation, area water well drilling logs, Stiff diagrams and water analysis, site monitor well drilling logs, and water sample analysis for samples used in the investigation.

Drilling operations at the Burke Unit #1 caused the temporary chloride contamination of two domestic water wells and longer lasting chloride contamination of a third well closer to the drill site. The operation was carried out in accordance with State regulations and special site restrictions required for urban areas, using rig engines equipped with mufflers, steel mud tanks for containment of drilling wastes, lining for earthen pits that may contain salt water, and the placement of a conductor casing to a depth of 120 feet to isolate the well from the freshwater zone beneath the rig.

The drilling location is underlain by permeable surface sand, with bedrock at a depth of less than 50 feet. Contamination of the ground water may have occurred when material flushed from the mud tanks remained in the lined pit for 13 days before removal. (The material contained high levels of chlorides, and liners can leak.) According to the State report, this would have allowed for sufficient time for contaminants to migrate into the freshwater aquifer. A leak from the produced water storage tank was also reported by the operator to have occurred before the contamination was detected in the water wells. One shallow well was less than 100 feet directly east of the drill pit area and 100 to 150 feet southeast of the produced water leak site. Chloride concentrations in this well measured by the Michigan Geological Survey were found to range from 750 (9/5/75) to 1,325 (5/23/75) ppm. By late August, two of the wells had returned to normal, while the third well still measured 28 times its original background concentration of chloride. (MI 04)[41]

In this case, damages resulted from practices that are not in violation of State regulations.

PLAINS

The Plains zone includes North Dakota, South Dakota, Nebraska, and Kansas. All of these States have oil and gas production, but for this study, Kansas was the only State visited for damage case collection. Discussion is limited to that State.

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41 References for case cited: Open file report, Michigan Department of Natural Resources, Report on Ground-Water Contamination, Sullivan and Company, J.D. Burke No. 1, Pennfield Township, conducted by J. R. Byerlay, 1976. Appendix includes correspondence relating to investigation, area water well drilling logs, Stiff diagrams and water analysis, site monitor well drilling logs, and water sample analysis for samples used in the investigation.

Operations

Oil and gas production in Kansas encompasses a wide geographical area and ranges from marginal oil production in the central and eastern portions of the State to significant gas production in the western portion of the State. Kansas is the home of one of the largest gas fields in the world, the Giant Hugoton field. Other major areas of oil production in Kansas include the Central Kansas Uplift area, better known as the "Kansas Oil Patch," the El Dorado Field in the east and south, and the Eastern Kansas Shoestring sandstone area. The Eastern Kansas Shoestring sandstone production area is composed mainly of marginal stripper operations. The overall ratio of produced water to oil in Kansas is about 40:1, but the ratio varies depending on economic conditions, which may force the higher water-to-oil ratio wells (i.e., those in the Mississippian and Arbuckle producing formations) to shut down.

The average depth of a new well drilled in Kansas in 1985 was 3,770 feet. In that year 6,025 new wells were completed. Of those, 1,694 were exploratory.

Types of Operators

Operators in Kansas include the full range from majors to small independents. The Hugoton area is dominated by majors and mid-sized to large independents. Spotty oil production in the northern half of eastern Kansas is dominated by small independent producers, and oil production is densely developed in the southern half.

Major Issues

Poor Lease Maintenance

There are documented cases in Kansas of damage associated with inadequate lease maintenance and illegal operation of pits. These cases commonly result in contamination of soil and surface water with high levels of chlorides as well as long-term chloride contamination of ground water.

Temple Oil Company and Wayside Production Company operated a number of oil production leases in Montgomery County. The leases were operated with illegally maintained saltwater containment ponds, improperly abandoned reserve pits, unapproved emergency saltwater pits, and improperly abandoned saltwater pits. Numerous oil and saltwater spills were recorded during operation of the sites. Documentation of these incidents started in 1977 when adjacent landowners began to complain about soil pollution, vegetation kills, fish kills, and pollution of freshwater streams due to oil and saltwater runoff from these sites. The leases also contain a large number of abandoned, unplugged wells, which may pose a threat to ground water.[42] Complaints were received by the Conservation Division, Kansas Department of Health and the Environment (KDHE), Montgomery County Sheriff, and Kansas Fish and Game Commission. A total of 39 violations on these leases were documented between 1983 and 1984.

A sample taken by KDHE from a 4 1/2-foot test hole between a freshwater pond and a creek on one lease showed chloride concentrations of 65,500 ppm. Water samples taken from pits on other leases showed chloride concentrations ranging from 5,000 to 82,000 ppm.

The Kansas Corporation Commission (KCC) issued an administrative order in 1984, fining Temple and Wayside a total of $80,000. Initially, $25,000 was collected, and the operators could reapply for licenses to operate in Kansas in 36 months if they initiated adequate corrective measures. The case is currently in private litigation. The KCC found that no progress had been made towards bringing the leases into compliance and, therefore, reassessed the outstanding $55,000 penalty. The KCC has since sought judical enforcement of that penalty in the District Court, and a journal entry has been signed and was reviewed by the KCC and is now ready to be filed in District Court. Additionally, in a separate lawsuit between the landowners, the lessors, and the Temples regarding operation of the leases, the landowners were successful and the leases have reverted back to the landowners. The new operators are prevented from operating without KCC authority. (KS 01)[43]

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[42] Comments in the Docket by the Kansas Corporation Commission (Beatrice Stong) pertain to KS 01. With regard to the abandoned wells, Kansas Corporation Commission states that these wells are "...cemented from top to bottom...", they have "...limited resource energy..." and the static fluid level these reservoirs could sustain are "...well below the location of any drinking or usable water."

[43] References for case cited: The Kansas Corporation Commission Court Order describing the evidence and charges against the Temple Oil Co., 5/17/84.

This case represents habitual violation of Kansas regulations.

On January 31, 1986, the Kansas Department of Health and the Environment (KDHE) inspected the Reitz lease in Montgomery County, operated by Marvin Harr of El Dorado, Arkansas. The lease included an unpermitted emergency pond containing water that had 56,500 ppm chlorides. A large seeping area was observed by KDHE inspectors on the south side of the pond, allowing the flow of salt water down the slope for about 30 feet. The company was notified and was asked to apply for a permit and install a liner because the pond was constructed of sandy clay and sandstone. The operator was directed to immediately empty the pond and backfill it if a liner was not installed. On February 24, the lease was reinspected by KDHE and the emergency pond was still full and actively seeping. It appeared that the lease had been shut down by the operator. A "pond order" was issued by KDHE requiring the company to drain and backfill the pond. On April 29, the pond was still full and seeping.

Water samples taken from the pit by KDHE showed chloride concentrations of from 30,500 ppm (4/29/86) to 56,500 ppm (1/31/86). Seepage from the pit showed chloride concentrations of 17,500 ppm (2/24/86). The Kansas Department of Health and the Environment stated that "...the use of the pond...has caused or is likely to cause pollution to the soil and the waters of the State." An administrative penalty of $500 was assessed against the operator, and it was ordered that the pond be drained and backfilled. (KS 08)[44]

This activity is in violation of current Kansas regulations.

Such incidents are a recognized problem in Kansas. On May 13, 1987, the Kansas Corporation (KCC) added new lease maintenance rules to their oil and gas regulations. These new rules require permits for all pits, drilling and producing, and require emptying of emergency pits within 48 hours. Spills must now be reported in 24 hours. The question of concern is how stringently these rules can be enforced, in the light of the evident reluctance of some operators to comply. (See Table VII-7.)

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44 References for case cited: Kansas Department of Health and Environment Order assessing civil penalty, in the matter of Marvin Harr, Case No. 86-E-77, 6/10/86. Pond Order issued by Kansas Department of Health and Environment, in the matter of Marvin Harr, Case No. 86-PO-008, 3/21/86.

Unlined Reserve Pits

Problems with unlined reserve pits are illustrated in the following cases.

Between February 9 and 27, 1986, the Elliott #1 was drilled on the property of Mr. Lawrence Koehling. The Hutchinson Salt member, an underground formation, was penetrated during the drilling of Elliott #1. The drilling process dissolved between 100 and 200 cubic feet of salt, which was disposed of in the unlined reserve pit. The reserve pit lies 200 feet away from a well used by Mr. Koenling for his ranching operations. Within a few weeks of the drilling of the Elliott #1, Mr. Koenling's nearby well began to pump water containing a saltwater drilling fluid.

Ground water on the Koehling ranch has been contaminated with high levels of chlorides allegedly because of leaching of the reserve pit fluids into the ground water. Water samples taken from the Koehling livestock water well by the KCC Conservation Division showed a chloride concentration of 1650 mg/L. Background concentrations of chlorides were in the range of 100 to 150 ppm. It is stated in a KCC report, dated November 1986, that further movement of the saltwater plume can be anticipated, thus polluting the Koehling domestic water well and the water well used by a farmstead over 1 mile downstream from the Koehling ranch. It is also stated in this KCC report that other wells drilled in the area using unlined reserve pits would have similarly affected the groundwater.

The KCC now believes the source of ground-water contamination is not the reserve pit from the Elliott #1. The KCC has drilled two monitoring wells, one 10 feet from the edge of the reserve pit location and the other within 400 feet of the affected water well, between the affected well and the reserve pit. The monitoring well drilled 10 feet from the reserve pit site tested 60 ppm chlorides. (EPA notes that it is not known if this monitoring well was located upgradient from the reserve pit.) The monitoring well drilled between the affected well and the reserve pit tested 750 ppm chlorides. (EPA notes that the level of chlorides in this monitoring well is more than twice the level of chlorides allowed under the EPA drinking water standards). The case is still open, pending further investigation. EPA believes that the evidence presented to date does not refute the earlier KCC report, which cited the reserve pit as the source of ground-water contamination, since the recent KCC report does not suggest an alternative source of contamination. (KS 05)[45]

Unpermitted reserve pits are in violation of current Kansas regulations.

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[45] References for case cited: Summary Report, Koehling Water Well Pollution, 22-10-15W, KCC, Conservation Division, Jim Schoof, Chief Engineer, 11/86.

Mr. Leslie, a private landowner in Kansas, suspected that chloride contamination of a natural spring occurred as a result of the presence of an abandoned reserve pit used when Western Drilling Inc. drilled a well (Leslie #1) at the Leslie Farm. Drilling in this area required penetration of the Hutchinson Salt member, during which 200 to 400 cubic feet of rock salt was dissolved and discharged into the reserve pit. The ground in the area consists of highly unconsolidated soils, which would allow for migration of pollutants into the ground water. Water at the top of the Leslie #1 had a conductivity of 5,050 umhos. Conductivity of the spring water equaled 7,250 umhos. As noted by the KCC, "very saline water" was coming out of the springs. Conductivity of 2,000 umhos will damage soil, precluding growth of vegetation. No fines were levied in this case as there were no violations of State rules and regulations. The Leslies filed suit in civil court and won their case for a total of $11,000 from the oil and gas operator.[46] (KS 03)[47]

Current Kansas regulations call for a site-by-site evaluation to determine if liners for reserve pits are appropriate.

Problems with Injection Wells

Problems with injection wells can occur as a result of inadequate maintenance, as illustrated by the following case.

On July 12, 1981, the Kansas Department of Health and the Environment (KDHE) received a complaint from Albert Richmeier, a landowner operating an irrigation well in the South Solomon River valley. His irrigation well had encountered salty water. An irrigation well belonging to an adjacent landowner, L. M. Paxson, had become salty in the fall of 1980. Oil has been produced in the area since 1952, and since 1962 secondary recovery by water flooding has been used. Upon investigation by the KDHE, it was discovered that the cause of the pollution was a saltwater injection well nearby, operated by Petro-Lewis. A casing profile caliper log was run by an operator-contractor under the direction of KDHE staff, which revealed numerous holes in the casing of the injection well. The producing formation, the Kansas City-Lansing, requires as much as 800 psi at the wellhead while injecting fluid to create a profitable enhanced oil recovery project. To remediate the contamination, the alluvial aquifer was pumped, and the initial chloride concentration of 6,000 mg/L was lowered to 600 to 700 mg/L in a year's time. Chloride contamination in some areas was lowered from 10,000 mg/L to near background levels. However, a contamination problem continues in the Paxson well, which shows chlorides in the range of 1,100 mg/L even though KDHE, through pumping, has tried to reduce the

46 API states that KDHE had authority over pits at this time. The KCC now requires permits for such pits.

47 Reference for case cited: Final Report, Gary Leslie Saltwater Pollution Problem, Kingman County, KCC Conservation Division, Jim Schoof, Chief Engineer, 9/86. Contains letters, memos, and analysis pertaining to the case.

concentration. After attempts at repair, Petro-Lewis decided to plug the injection well.[48] (KS 06)[49]

Operation of such a well would violate current Kansas and UIC regulations.

TEXAS/OKLAHOMA

The Texas/Oklahoma zone includes these two States, both of which are large producers of oil and gas. As of December 1986, Texas ranked as the number one producer in the U.S. among all oil-producing States. Because of scheduling constraints, research on this zone concentrated on Texas, and most of the damage cases collected come from that State.

Operations

Oil and gas operations in Texas and Oklahoma began in the 1860s and are among the most mature and extensively developed in the U.S. These two States include virtually all types of operations, from large-scale exploratory projects and enhanced recovery projects to marginal small-scale stripper operations. In fact, the Texas/Oklahoma zone includes most of the country's stripper well production. Because of their maturity, many operations in the area generate significant quantities of associated produced water.

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48 Comments in the Docket by the KCC (Bill Bryson) pertain to KS 06. KCC states that of the affected irrigation wells, one is "...back in service and the second is approaching near normal levels as it continues to be pumped." API states that Kansas received primacy for the UIC program in 1984.

49 References for case cited: Richmeier Pollution Study, Kansas Department of Health and Environment, G. Blackburn and W. R. Bryson, 1983.

Development of oil and gas reserves remains active. In 1985, some 9,176 new wells were completed in Oklahoma, 385 of which were exploration wells. In Texas in the same year, 25,721 wells were completed on shore, 3,973 of which were exploration wells. The average depth of wells in the two areas is comparable: Oklahoma, 4,752 feet; Texas, 4,877 feet. Because the scale and character of operations varies so widely, cases of environmental damage from this zone are also varied and are not limited to any particular type of operation.

Types of Operators

Major operators are the principal players in exploration and development of deep frontiers and capital-intensive secondary and tertiary recovery projects. As elsewhere, the major companies have the best record of compliance with environmental requirements of all types; they are least likely to cut corners on operations, tend to use high-quality materials and methods when drilling, and are generally responsible in handling well abandonment obligations.

Smaller independent operators in the zone are more susceptible to fluctuating market conditions. They may lack sufficient capital to purchase first-quality materials and employ best available operating methods.

Major Issues

Discharge of Produced Water and Drilling Muds into Bays and Estuaries of the Texas Gulf Coast

Texas allows the discharge of produced water into tidally affected estuaries and bays of the Gulf Coast from nearby onshore development. Cases in which permitted discharges have created damage include:

In Texas, oil and gas producers operating near the Gulf Coast are permitted to discharge produced water into surface streams if they are found to be tidally affected. Along with the produced water, residual production chemicals and organic constituents may be discharged, including lead, zinc, chromium, barium, and water-soluble polycyclic aromatic hydrocarbons (PAHs). PAHs are known to accumulate in sediment, producing liver and lip tumors in catfish and affecting mixed function oxidase systems of mammals, rendering a reduced immune response. In 1984, a study conducted by the U.S. Fish and Wildlife Service of sediment in Tabb's Bay, which receives discharged produced water as well as discharges from upstream industry (i.e., discharges from ships in the Houston Ship Channel), indicates severe degradation of the environment by PAH contamination. Sediment was collected from within 100 yards of several tidal discharge points of oil field produced water. Analytical results of these sediments indicated severe degradation of the environment by PAH contamination. The study noted that sediments contained no benthic fauna, and because of wave action, the contaminants were continuously resuspended, allowing chronic exposure of contaminants to the water column. It is concluded by the U.S. Fish and Wildlife Service that shrimp, crabs, oysters, fish, and fish-eating birds in this location have the potential to be heavily contaminated with PAHs. While these discharges have to be within Texas Water Quality Standards, these standards are for conventional pollutants and do not consider the water soluble components of oil that are in produced water such as PAHs.[50] (TX 55)[51]

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[50] NPDES permits have been applied for, but EPA has not issued permits for these discharges on the Gulf Coast. The Texas Railroad Commission (TRC) issues permits for these discharges. The TRC disagrees with the source of damage in this case.

[51] References for case cited: Letter from U.S. Department of the Interior, Fish and Wildlife Service, signed by H. Dale Hall, to Railroad Commission of Texas, discussing degradation of Tabb's Bay because of discharge of produced water in upstream estuaries; includes lab analysis for polycyclic aromatic hydrocarbons in Tabb's Bay sediment samples. Texas Railroad Commission Proposal for Decision on Petronilla Creek case documenting that something other than produced water is killing aquatic organisms in the creek. (Roy Spears, Texas Parks and Wildlife, did LC50 study on sunfish and sheepshead minnows using produced water and Aranssas Bay water. Produced water diluted to proper salinity caused mortality of 50 percent. (Seawater contains 19,000 ppm chlorides.)

These discharges are not in violation of existing regulations.

Produced water discharges contain a high ratio of calcium ions to magnesium ions. This high ratio of calcium to magnesium has been found by Texas Parks and Wildlife officials to be lethal to common Atlantic croaker, even when total salinity levels are within tolerable limits. In a bioassay study conducted by Texas Parks and Wildlife, this fish was exposed to various ratios of calcium to magnesium, and it was found that in 96-hour LC50 studies, mortality was 50 percent when exposed to calcium-magnesium ratios of 6:1, the natural ratio being 1:3. Nearly all of oil field produced water discharges on file with the Army Corps of Engineers in Galveston contain ratios exceeding the 6:1 ratio, known to cause mortality in Atlantic croaker as established by the LC50 test.[52] (TX 31)[53]

These discharges are not in violation of current regulations.

Until very recently, the Texas Railroad Commission (TRC) allowed discharge of produced water into Petronilla Creek, parts of which are 20 miles inland and not tidally affected.

For over 50 years, oil operators (including Texaco and Amoco) have been allowed to discharge produced water into Petronilla Creek, a supposedly tidally influenced creek. Discharge areas were as much as 20 miles inland and contained fresh water. In 1981, the pollution of Petronilla Creek from discharge of produced water became an issue when studies done by the Texas Parks and Wildlife and Texas Department of Water Resources documented the severe degradation of the water and damage to native fish and vegetation. All freshwater species of fish and vegetation were dead because of exposure to toxic constituents in discharge liquid. Portions of the creek were black or bright orange in color. Heavy oil slicks and oily slime were observable along discharge areas.

Impacts were observed in Baffin Bay, into which the creek empties. Petronilla Creek is the only freshwater source for Baffin Bay, which is a nursery for many fish and shellfish in the Gulf of Mexico. Sediments in Baffin Bay show elevated levels of toxic constituents found in Petronilla Creek. For 5 years, the Texas Department of Water Resources and Texas Parks and Wildlife, along with environmental groups, worked to have the discharges stopped. In 1981, a hearing was held by the Texas Railroad Commission (TRC). The conclusion of the hearing was that discharge of the produced water plus disposal of other trash by the public was degrading Petronilla Creek. The TRC initiated a joint committee (Texas Department of Water Resources, Texas Parks and Wildlife Department, and TRC) to establish the source of the trash, clean up

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[52] API comments in the Docket pertain to TX 31. API states that models show that "...rapid mixing in Bay waters results in no pollution to Bay waters as a whole from calcium ions or from the calcium-magnesium ratio."

[53] References for case cited: Toxic Effects of Calcium on the Atlantic Croaker: An Investigation of One Component of Oil Field Brine, by Kenneth N. Knudson and Charles E. Belaire, undated.

trash from the creek, and conduct additional studies. After this work was completed, a second hearing was held in 1984. The creek was shown to contain high levels of chromium, barium, oil, grease, and EPA priority pollutants naphthalene and benzene. Oil operators stated that a no dumping order would put them out of business because oil production in this area is marginal. In 1986, the TRC ordered a halt to discharge of produced water into nontidal portions of Petronilla Creek. (TX 29)[54]

Although discharges are now prohibited in this creek, they are allowed in other tidally affected areas.

Long-term environmental impacts associated with this type of discharge are unknown, because of limited documentation and analysis. Bioaccumulation of heavy metals in the food chain of estuaries could potentially affect human health through consumption of crabs, clams, and other foods harvested off the Texas Gulf Coast.

Alternatives to coastal discharge do exist. They include underground injection of produced water and use of produced water tanks. While the Texas Railroad Commission has not stopped the practice of coastal discharge, it is currently evaluating the need to preclude this type of discharge by collecting data from new applications, and it is seeking delegation of the NPDES program under the Federal Clean Water Act. The TRC currently asks applicants for tidal discharge permits to analyze the produced water to be discharged for approximately 20 to 25 constituents.

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54 References for case cited: The Effects of Brine Water Discharges on Petronilla Creek, Texas Parks and Wildlife Department, 1981. Texas Department of Water Resources interoffice memorandum documenting spills in Petronilla Creek from 1980 to 1983. The Influence of Oilfield Brine Water Discharges on Chemical and Biological Conditions in Petronilla Creek, by Frank Shipley, Texas Department of Water Resources, 1984. Letter from Dick Whittington, EPA, to Richard Lowerre, documenting absence of NPDES permits for discharge to Petronilla Creek. Final Order of TRC, banning discharge of produced water to Petronilla Creek, 6/23/86. Numerous letters, articles, legal documents, on Petronilla Creek case.

Leaching of Reserve Pit Constituents into Ground Water

Leaching of reserve pit constituents into ground water and soil is a problem in the Texas/Oklahoma zone. Reserve pit liners are generally not required in Texas and Oklahoma. When pits are constructed in permeable soil without liners, a higher potential exists for migration of reserve pit constituents into ground water and soil. Although pollutant migration may not always occur during the active life of the reserve pit, problems can occur after closure when dewatered drilling mud begins to leach into the surrounding soil. Pollutants may include chlorides, sodium, barium, chromium, and arsenic.

On November 20, 1981, the Michigan-Wisconsin Pipe Line Company began drilling an oil and gas well on the property of Ralph and Judy Walker. Drilling was completed on March 27, 1982. Unlined reserve pits were used at the drill site. After 2 months of drilling, the water well used by the Walkers became polluted with elevated levels of chloride and barium (683 ppm and 1,750 ppb, respectively). The Walkers were forced to haul fresh water from Elk City for household use. The Walkers filed a complaint with the Oklahoma Corporation Commission (OCC), and an investigation was conducted. The Michigan-Wisconsin Pipe Line Co. was ordered to remove all drilling mud from the reserve pit.

In the end, the Walkers retained a private attorney and sued Michigan-Wisconsin for damages sustained because of migration of reserve pit fluids into the freshwater aquifer from which they drew their domestic water supply. The Walkers won their case and received an award of $50,000.[55] (OK 08)[56]

Constructing a reserve pit over a fractured shale, as in this case, is a violation of OCC rules.

In 1973, Horizon Oil and Gas drilled an oil well on the property of Dorothy Moore. As was the common practice, the reserve pit was dewatered, and the remaining mud was buried on site. In 1985-86, problems from the buried reserve pit waste began to appear. The reserve pit contents

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[55] API states that the Oklahoma Corporation Commission is in the process of developing regulations to prevent leaching of salt muds into ground water.

[56] References for case cited: Pretrial Order, Ralph Gail Walker and Judy Walker vs. Michigan-Wisconsin Pipe Line Company and Big Chief Drilling Company, U.S. District Court, Western District of Oklahoma, #CIV-82-1726-R. Direct Examination of Stephen G. McLin, Ph. D. Direct Examination of Robert Hall. Direct Examination of Laurence Alatshuler, M. D. Lab results from Walker water well.

were seeping into a nearby creek and pond. The surrounding soil had very high chloride content as established by Dr. Billy Tucker, an agronomist and soil scientist. Extensive erosion around the reserve pit became evident, a common problem with high-salinity soil. Oil slicks were visible in the adjacent creek and pond. An irrigation well on the property was tested by Dr. Tucker and was found to have 3000 ppm chlorides; however, no monitoring wells had been drilled to test the ground water prior to the drilling of the oil well, and background levels of chlorides were not established. Dorothy Moore has filed civil suit against the operator for damages sustained during the oil and gas drilling activity. The case is pending.[57] (OK 02)[58]

Oklahoma performance standards prohibit leakage of reserve pits into ground water.

Chloride Contamination of Ground Water from Operation of Injection Wells

The Texas/Oklahoma zone contains a large number of injection wells used both for disposal of produced water and for enhanced or tertiary recovery projects. This large number of injection wells increases the potential for injection well casing leaks and the possibility of ground water contamination.

The Devore #1, a saltwater injection well located on the property of Verl and Virginia Hentges, was drilled in 1947 as an exploratory well. Shortly afterwards, it was permitted by the Oklahoma Corporation Commission (OCC) as a saltwater injection well. The injection formation, the Layton, was known to be capable of accepting 80 barrels per hour at 150 psi. In 1984, George Kahn acquired the well and the OCC granted an exception to Rule 3-305, Operating Requirements for Enhanced Recovery Injection and Disposal Wells, and permitted the well to inject 2,000 barrels per day at 400 psi. Later in 1984, it appeared that there was saltwater migration from the intended injection zone of the Devore #1 to the surface.[59] The Hentges alleged that the migrating salt water had polluted the ground water used on their ranch.

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[57] API comments in the Docket pertain to OK 02. API states that "...there is no evidence that there has been any seepage whatsoever into surface water." API states that there are no irrigation wells on Mrs. Moore's farm. Further, it states that erosion has been occurring for years and is the "...result of natural conditions coupled with the failure of Mrs. Moore to repair terraces to prevent or limit such erosion." API has not provided supporting documentation.

[58] References for case cited: Extensive soil and water analysis results collected and interpreted by Dr. Billy Tucker, agronomist and soil scientist, Stillwater, Okla. Correspondence and conversation with Randall Wood, private attorney, Stack and Barnes, Oklahoma City, Okla.

[59] Comments by API in the Docket pertain to OK 06. API states that "...tests on the well pressure test and tracer logs indicate the injection well is not a source of salt water." API has not provided documentation with this statement.

In addition, they alleged that the migrating salt water was finding its way to the surface and polluting Warren Creek, a freshwater stream used by downstream residents for domestic water. Salt water discharged to the surface had contaminated the soil and had caused vegetation kills. A report by the OCC concluded that "...the Devore #1 salt water disposal well operations are responsible for the contaminant plume in the adjacent alluvium and streams." The OCC required that a workover be done on the well. The workover was completed, and the operator continued to dispose of salt water in the well. The Hentges then sought private legal assistance and filed a lawsuit against George Kahn, the operator, for $300,000 in actual damages and $3,000,000 in punitive damages. The lawsuit is pending, scheduled for trial in October 1987.[60]
(OK 06)[61]

Although at the time, the OCC permitted injection into the well at pressures that may have polluted the ground water, Oklahoma prohibits any contamination of drinking-water aquifers.

Illegal Disposal of Oil and Gas Wastes

Illegal disposal of oil and gas exploration and production wastes is a common problem in the Texas/Oklahoma zone. Illegal disposal can take many forms, including breaching of reserve pits, emptying of vacuum trucks into fields and ditches, and draining of produced water onto the land surface. Damage to surface soil, vegetation, and surface water may result as illustrated by the examples below.

On May 16, 1984, Esenjay Petroleum Co. had completed the L.W. Bing #1 well at a depth of 9,900 feet and had hired T&L Lease Service to clean up the drill site. During cleanup, the reserve pit, containing high-chromium drilling mud, was breached by T&L Lease Service, allowing drilling mud to flow into a tributary of Hardy Sandy Creek. The drilling mud was up to 24 inches deep along the north bank of Hardy Sandy. Drilling mud had been pushed into the trees and brush adjacent to the drill site. The spill was reported to the operator and the Texas Railroad Commission (TRC). The TRC ordered cleanup, which began on May 20.

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60 API states that the operator now believes old abandoned saltwater pits to be the source of contamination as the well now passes UIC tests.

61 References for case cited: Remedial Action Plan for Aquifer Restoration within Section #2, Township 21 North, Range 2 West, Noble County, Oklahoma, by Stephen G. McLin, Ph. D. Surface Pollution at the De Vore #1 Saltwater Disposal Site, Oklahoma Corporation Commission, 1986. District Court of Noble County, Amended Petition, Verl E. Hentges and Virginia L. Hentges vs. George Kahn, #C-84-110, 7/25/85. Lab analysis records of De Vore well from Oklahoma Corporation Commission and Southwell Labs. Communication with Alan DeVore, plaintiffs' attorney.

Because of high levels of chromium contained in the drilling mud, warnings were issued by the Lavaca-Navidad River Authority to residents and landowners downstream of the spill as it represented a possible health hazard to cattle watering from the affected streams. The River Authority also advised against eating the fish from the affected waters because of the high chromium levels in the drilling mud. (TX 21)[62]

This discharge was a violation of State and Federal regulations.

On September 15, 1983, TXO Production Company began drilling its Dunn Lease Well No. B2 in Live Oak County. On October 5, 1983, employees of TXO broke the reserve pit levee and began spreading drilling mud downhill from the site, towards the fence line of property owned by the Dunns. By October 9, the mud had entered the draw that flows into two stock tanks on the Dunn property. On November 24 and 25, dead fish were observed in the stock tank. On December 17, Texas Parks and Wildlife documented over 700 fish killed in the stock tanks on the Dunn property. Despite repeated requests by the Dunns, TXO did not clean up the drilling mud and polluted water from the Dunn property.

Lab results from TRC and Texas Department of Health indicated that the spilled drilling mud was high in levels of arsenic, barium, chromium, lead, sulfates, other metals, and chlorides. In February 1984, the TRC stated that the stock tanks contained unacceptable levels of nitrogen, barium, chromium, and iron, and that the chemicals present were detrimental to both fish and livestock. (The Dunns water their cows at this same stock tank.) After further analysis, the TRC issued a memorandum stating that the fish had died because of a cold front moving through the area, in spite of the fact that the soil, sediment, and water in and around the stock pond contained harmful substances. Ultimately, TXO was fined $1,000 by the TRC, and TXO paid the Dunns a cash settlement for damages sustained.[63] (TX 22)[64]

This activity was in violation of Texas regulations.

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[62] References for case cited: Memorandum from Lavaca-Navidad River Authority documenting events of Esenjay reserve pit discharge, 6/27/84, signed by J. Henry Neason. Letter to TRC from Lavaca-Navidad River Authority thanking the TRC for taking action on the Esenjay case, "Thanks to your enforcement actions, we are slowly educating the operators in this area on how to work within the law." Agreed Order, Texas Railroad Commission, #2-83,043, 11/12/84, fining Esenjay $10,000 for deliberate discharge of drilling muds. Letter from U.S. EPA to TRC inviting TRC to attend meeting with Esenjay Petroleum to discuss discharge of reserve pit into Hardy Sandy Creek, 6/1/84, signed by Thomas G. Giesberg. Texas Railroad Commission spill report on Esenjay operations, 5/18/84.

[63] API states that the fish died from oxygen depletion of the water. The Texas Railroad Commission believes that the fish died from exposure to cold weather.

[64] References for case cited: Texas Railroad Commission Motion to Expand Scope of Hearing, #2-82,919, 6/29/84. Texas Railroad Commission Agreed Order, #2-82,919, 12/17/84. Analysis by Texas Veterinary Medical Diagnostic Laboratory System on dead fish in Dunn stock tank. Water and soil sample analysis from the Texas Railroad Commission. Water and soil samples from the Texas Department of Health. Letter from Wendell Taylor, TRC, to Jerry Mullican, TRC, stating that the fish kill was the result of cold weather, 7/13/84. Miscellaneous letters and memos.

NORTHERN MOUNTAIN

The Northern zone includes Idaho, Montana, and Wyoming. Idaho has no commercial production of oil or gas. Montana has moderate oil and gas production. Wyoming has substantial oil and gas production and accounts for all the damage cases discussed in this section.

Operations

Significant volumes of both oil and gas are produced in Wyoming. Activities range from small, marginal operations to major capital- and energy-intensive projects. Oil production comes both from mature fields producing high volumes of produced water and from newly discovered fields, where oil/water ratios are still relatively low. Gas production comes from mature fields as well as from very large new discoveries.

Although the average new well drilled in Wyoming in 1985 was about 7,150 feet, exploration in the State can be into strata as deep as 25,000 feet. In 1985, 1,332 new wells were completed in Wyoming, of which 541 were exploratory.

Types of Operators

Because of the capital-intensive nature of secondary and tertiary recovery projects and large-scale drilling projects, many operations in the State are conducted by the major oil companies. These companies are likely to implement environmental controls properly during drilling and completion and are generally responsible in carrying out their well abandonment obligations. Independents also operate in Wyoming, producing a significant amount of oil and gas in the State. Independent operators may be more vulnerable to fluctuating market conditions and may be more likely to maintain profitability at the expense of environmental protection.

Major Issues

Illegal Disposal of Oil and Gas Wastes

Wyoming Department of Environmental Quality officials believe that illegal disposal of wastes is the most pervasive environmental problem associated with oil and gas operations in Wyoming. Enforcement of State regulations is made difficult as resources are scarce and areas to be patrolled are large and remote. (See Table VII-7.)

Altex Oil Company and its predecessors have operated an oil production field for several decades south of Rozet, Wyoming. (Altex purchased the property in 1984.) An access road runs through the area, which, according to Wyoming Department of Environmental Quality (WDEQ), for years was used as a drainage for produced water from the oil field operations.

In August of 1985, an official with WDEQ collected soil samples from the road ditch to ascertain chloride levels because it had been observed that trees and vegetation along the road were dead or dying. WDEQ analysis of the samples showed chloride levels as high as 130,000 ppm. The road was chained off in October of 1985 to preclude any further illegal disposal of produced water.[65] (WY 03)[66]

In early October 1985, Cities Service Oil Company had completed drilling at a site northeast of Cheyenne on Highway 85. The drilling contractor, Z&S Oil Construction Company, was suspected of illegally disposing of drilling fluids at a site over a mile away on the Pole Creek Ranch. An employee of Z&S had given an anonymous tip to a County detective. A stake-out of the

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[65] Comments in the Docket from the Wyoming Oil and Gas Conservation Commission (WOGCC) (Mr. Don Basko) pertain to WY 03. WOGCC states that "...not all water from Altex Oil producing wells... caused the contamination problem." Further, WOGCC states that "Illegal dumping, as well as a flow line break the previous winter, had caused a high level of chloride in the soil which probably contributed to the sagebrush and cottonwood trees dying."

[66] References for case cited: Analysis of site by the Wyoming Department of Environmental Quality (WDEQ), Quality Division Laboratory, File #ej52179, 12/6/85. Photographs of dead and dying cottonwood trees and sagebrush in and around site. Conversation with WDEQ officials.

illegal operation was made with law enforcement and WDEQ personnel. Stake-out personnel took samples and photos of the reserve pit and the dump site. During the stake-out, vacuum trucks were witnessed draining reserve pit contents down a slope and into a small pond on the Pole Creek Ranch. After sufficient evidence had been gathered, arrests were made by Wyoming law enforcement personnel, and the trucks were impounded. The State sued Z&S and won a total of $10,000. (WY 01)[67]

This activity was in violation of Wyoming regulations.

During the week of April 8, 1985, field personnel at the Byron/Garland field operated by Marathon Oil Company were cleaning up a storage yard used to store drums of oil field chemicals. Drums containing discarded production chemicals were punctured by the field employees and allowed to drain into a ditch adjacent to the yard. Approximately 200 drums containing 420 gallons of fluid were drained into the trench. The chemicals were demulsifiers, reverse demulsifiers, scale and corrosion inhibitors, and surfactants. Broken transformers containing PCBs were leaking into soil in a nearby area. Upon discovery of the condition of the yard, Wyoming Department of Environmental Quality (WDEQ) ordered Marathon to begin cleanup procedures. At the request of the WDEQ, ground-water monitors were installed, and monitoring of nearby Arnoldus Lake was begun. The State filed a civil suit against Marathon and won a $5000 fine and $3006 in expenses for lab work.[68] (WY 05)[69]

This activity was in direct violation of Wyoming regulations.

Reclamation Problems

Although Wyoming's mining industry has rules governing reclamation of sites, no such rules exist covering oil and gas operations. As a result, reclamation on privately owned land is often inadequate or entirely lacking, according to WDEQ officials. By contrast, reclamation on Federal lands is believed to be consistently more thorough, since Federal

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67 References for case cited: WDEQ memorandum documenting chronology of events leading to arrest of Z&S employees and owners. Lab analysis of reserve pit mud and effluent, and mud and effluent found at dump site. Consent decree from District Court of First Judicial District, Laramie County, Wyoming, docket #108-493, The People of the State of Wyoming vs. Z&S Construction Company. Photographs of vacuum trucks dumping at Pole Creek Ranch.

68 API states that the operator, thinking the drums had to be empty before transport offsite, turned the drums upside down and drained 420 gallons of chemicals into the trench.

69 References for case cited: Summary of Byron-Garland case by Marathon employee J. C. Fowler. List of drums, contents, and field uses. Cross-section of disposal trench area. Several sets of lab analyses. Map of Garland field disposal yard. Newspaper articles on incident. District court consent decree, The People of the State of Wyoming vs. Marathon Oil Company, #108-87.

leases specify reclamation procedures to be used on specific sites. WDEQ officials state that this will be of growing concern as the State continues to be opened up to oil and gas development.[70]

WDEQ officials have photographs and letters from concerned landowners, regarding reclamation problems, but no developed cases. The Wyoming Oil and Gas Conservation Commission submitted photographs documenting comparable reclamation on both Federal and private lands. The issue is at least partially related to drilling waste management, since improper reclamation of sites often involves inadequate dewatering of reserve pits before closure. As a result of this inadequate dewatering, reserve pit constituents, usually chlorides, are alleged to migrate up and out of the pit, making revegetation difficult. The potential also exists for migration of reserve pit constituents into ground water.

Discharge of Produced Water into Surface Streams

Because much of the produced water in Wyoming is relatively low in chlorides, several operations under the beneficial use provision of the Federal NPDES permit program are allowed to discharge produced water directly into dry stream beds or live streams. The practice of chronic discharge of low-level pollutants may be harmful to aquatic communities in these streams, since residual hydrocarbons contained in produced water appear to suppress species diversity in live streams.

A study was undertaken by the Columbia National Fisheries Research Laboratory of the U. S. Fish and Wildlife Service to determine the effect of continuous discharge of low-level oil effluent into a stream and the resulting effect on the aquatic community in the stream. The discharges to the stream contained 5.6 mg/L total hydrocarbons. Total hydrocarbons in the receiving sediment were 979 mg/L to 2,515 mg/L. During the study, samples were taken upstream

[70] WOGCC disagrees with WDEQ on this statement.

and downstream from the discharge. Species diversity and community structure were studied. Water analysis was done on upstream and downstream samples. The study found a decrease in species diversity of the macrobenthos community (fish) downstream from the discharge, further characterized by total elimination of some species and drastic alteration of community structure. The study found that the downstream community was characterized by only one dominant species, while the upstream community was dominated by three species. Total hydrocarbon concentrations in water and sediment increased 40 to 55 fold downstream from the discharge of produced water. The authors of the study stated that "...based on our findings, the fisheries and aquatic resources would be protected if discharge of oil into fresh water were regulated to prevent concentrations in receiving streams water and sediment that would alter structure of macrobenthos communities." (WY 07)[71]

These discharges are permitted under NPDES.

SOUTHERN MOUNTAIN

The Southern Mountain zone includes the States of Nevada, Utah, Arizona, Colorado, and New Mexico. All five States have some oil and gas production, but New Mexico's is the most significant. The discussion below is limited to New Mexico.

Operations

Although hydrocarbon production is scattered throughout New Mexico, most comes from two distinct areas within the State: the Permian Basin in the southeast corner and the San Juan Basin in the northwest corner.

Permian Basin production is primarily oil, and it is derived from several major fields. Numerous large capital- and energy-intensive enhanced recovery projects within the basin make extensive use of CO_2 flooding. The area also contains some small fields in which production

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[71] References for case cited: Petroleum Hydrocarbon Concentrations in a Salmonid Stream Contaminated by Oil Field Discharge Water and Effects on the Macrobenthos Community, by D.F. Woodward and R.G. Riley, U.S. Department of the Interior, Fish and Wildlife Service, Columbia National Fisheries Research Laboratory, Jackson, Wyoming, 1980; submitted to Transactions of the American Fisheries Society.

is derived from marginal stripper operations. This is a mature production area that is unlikely to see extensive exploration in the future. The Tucumcari Basin to the north of the Permian may, however, experience extensive future exploration if economic conditions are favorable.

The San Juan Basin is, for the most part, a large, mature field that produces primarily gas. Significant gas finds are still made, including many on Indian Reservation lands. As Indian lands are gradually opened to oil and gas development, exploration and development of the basin as a whole will continue and possibly increase.

Much of the State has yet to be explored for oil and gas. The average depth of new wells drilled in 1985 was 6,026 feet. The number of new wells drilled in 1985 was 1,734, of which 281 were exploratory.

Types of Operators

The capital- and energy-intensive enhanced recovery projects in the Permian Basin, as well as the exploratory activities under way around the State, are conducted by the major oil companies. Overall, however, the most numerous operators are small and medium-sized independents. Small independents dominate marginal stripper production in the Permian Basin. Production in the San Juan Basin is dominated by midsize independent operators.

Major Issues

Produced Water Pit and Oil Field Waste Pit Contents Leaching into Ground Water

New Mexico, unlike most other States, still permits the use of unlined pits for disposal of produced water. This practice has the potential for contamination of ground water.

In July 1985, a study was undertaken in the Duncan Oil Field in the San Juan Basin by faculty members in the Department of Chemistry at New Mexico State University, to analyze the potential for unlined produced water pit contents, including hydrocarbons and aromatic hydrocarbons, to migrate into the ground water. The oil field is situated in a flood plain of the San Juan River. The site chosen for investigation by the study group was similar to at least 1,500 other nearby production sites in the flood plain. The study group dug test pits around the disposal pit on the chosen site. These test pits were placed abovegradient and downgradient of the disposal pit, at 25- and 50-meter intervals. A total of 9 test pits were dug to a depth of 2 meters, and soil and ground-water samples were obtained from each test pit. Upon analysis, the study group found volatile aromatic hydrocarbons were present in both the soil and water samples of test pits downgradient, demonstrating migration of unlined produced water pit contents into the ground water.

Environmental impact was summarized by the study group as contamination of shallow ground water with produced water pit contents due to leaching from an unlined produced water disposal pit. Benzene was found in concentrations of 0.10 ppb. New Mexico Water Quality Control Commission standard is 10 ppb. Concentrations of ethylbenzene, xylenes, and larger hydrocarbon molecules were found. No contamination was found in test pits placed abovegradient from the disposal pit. Physical signs of contamination were also present, downgradient from the disposal pit, including black, oily staining of sands above the water table and black, oily film on the water itself. Hydrocarbon odor was also present. (NM 02)[72]

It is now illegal to dispose of more than five barrels per day of produced water into unlined pits in this part of New Mexico.

As a result of this study, the use of unlined produced water pits was limited by the State to wells producing no more than five barrels per day of produced water. While this is a more stringent requirement than the previous rule, the potential for contamination of ground water with hydrocarbons and chlorides still exists. It is estimated by individuals familiar with the industry in the State that 20,000 unlined emergency

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[72] References for case cited: Hydrocarbons and Aromatic Hydrocarbons in Groundwater Surrounding an Earthen Waste Disposal Pit for Produced Water in the Duncan Oil Field of New Mexico, by G.A. Eiceman, J.T. McConnon, Masud Zaman, Chris Shuey, and Douglas Earp, 9/16/85. Polycyclic Aromatic Hydrocarbons in Soil at Groundwater Level Near an Earthen Pit for Produced Water in the Duncan Oil Field, by B. Davani, K. Lindley, and G.A. Eiceman, 1986. New Mexico Oil Conservation Commission hearing to define vulnerable aquifers, comments on the hearing record by Intervenor Chris Shuey, Case No. 8224.

produced water disposal pits are still in existence in the San Juan Basin area of New Mexico.[73]

New Mexico has experienced problems that may be due to centralized oil field waste disposal facilities:

Lee Acres "modified" landfill (meaning refuse is covered weekly instead of daily as is done in a "sanitary" landfill) is located 4.5 miles E-SE of Farmington, New Mexico. It is owned by the U.S. Bureau of Land Management (BLM). The landfill is approximately 60 acres in size and includes four unlined liquid-waste lagoons or pits, three of which were actively used. Since 1981, a variety of liquid wastes associated with the oil and gas industry have been disposed of in the lagoons. The predominant portion of liquid wastes disposed of in the lagoons was produced water, which is known to contain aromatic volatile organic compounds (VOCs). According to the New Mexico Department of Health and Environment, Environmental Improvement Division, 75 to 90 percent of the produced water disposed of in the lagoons originated from Federal and Indian oil and gas leases managed by BLM. Water produced on these leases was hauled from as far away as Nageezi, which is 40 miles from the Lee Acres site. Disposal of produced water in these unlined pits was, according to New Mexico State officials, in direct violation of BLM's rule NTL-2B, which prohibits, without prior approval, disposal of produced waters into unlined pits, originating on Federally owned leases. The Department of the Interior states that disposal in the lagoons was "...specifically authorized by the State of New Mexico for disposal of produced water." The State of New Mexico states that "There is no truth whatsoever to the assertion that the landfill lagoons were specifically authorized by the State of New Mexico for disposal of produced water." Use of the pits ceased on 4/19/85; 8,800 cubic yards of waste were disposed of prior to closure.

New Mexico's Environmental Improvement Division (NMEID) asserts that leachate from the unlined waste lagoons that contain oil and gas wastes has contributed to the contamination of several water wells in the Lee Acres housing subdivision located downgradient from the lagoons and downgradient from a refinery operated by Giant, located nearby. NMEID has on file a soil gas survey that documents extensive contamination with chlorinated VOCs at the landfill site. High levels of sodium, chlorides, lead, chromium, benzene, toluene, xylenes, chloroethane, and trichloroethylene were found in the waste lagoons. An electromagnetic terrain survey of the Lee Acres landfill site and surrounding area, conducted by NMEID, located a plume of contaminated ground water extending from the landfill. This plume runs into a plume of contamination known to exist, emanating from the refinery. The plumes have become mixed and are the source of

[73] Governor Carruthers refutes this and states that "Unlined pits in fresh water areas in Southeast New Mexico were banned beginning in 1956, with a general prohibition adopted in 1967." EPA notes that New Mexico still permits unlined pits to be used for disposal of produced water if the pit does not receive more than five barrels of produced water per day.

contamination of the ground water serving the Lee Acres housing subdivision.[74] One domestic well was sampled extensively by NMEID and was found to contain extremely high levels of chlorides and elevated levels of chlorinated VOCs, including trichloroethane. (Department of the Interior (DOI) states that it is unaware of any violations of New Mexico ground-water standards involved in this case. New Mexico states that State ground-water standards for chloride, total dissolved solids, benzene, xylenes, 1,1-dichloroethane, and ethylene dichloride have been violated as a result of the plume of contamination. In addition, the EPA Safe Drinking Water Standard for trichloroethylene has been violated.) New Mexico State officials state that "The landfill appears to be the principal source of chloride, total dissolved solids and most chlorinated VOCs, while the refinery appears to be the principal source of aromatic VOCs and ethylene dichloride."

During the period after disposal operations ceased and before the site was closed, access to the lagoons was essentially unrestricted. While NMEID believes that it is possible that non-oil and gas wastes illegally disposed of during this period may have contributed to the documented contamination, the primary source of ground-water contamination appears to be from oil and gas wastes.

The State has ordered BLM to provide public water to residents affected by the contamination, develop a ground-water monitoring system, and investigate the types of drilling, drilling procedures, and well construction methods that generated the waste accepted by the landfill. BLM submitted a motion-to-stay the order so as to include Giant Refining Company and El Paso Natural Gas in cleanup operations. The motion was denied. The case went into litigation. According to State officials, "The State of New Mexico agreed to dismiss its lawsuit only after the Bureau of Land Management agreed to conduct a somewhat detailed hydrogeologic investigation in a reasonably expeditious period of time. The lawsuit was not dismissed because of lack of evidence of contamination emanating from the landfill." The refinery company has completed an

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74 In a letter dated 8/20/87, Giant Refining Company states that "Benzene, toluene and xylenes are naturally occurring compounds in crude oil, and are consequently in high concentrations in the produced water associated with that crude oil. The only gasoline additive used by Giant that has been found in the water of a residential well is DCA (ethylene dichloride) which has also been found in the landfill plume." Giant also notes that the refinery leaks in the last 2 years resulted in less than 30,000 gallons of diesel being released rather than the 100,000 gallons stated by the Department of Interior in a letter to EPA of 8/11/87.

extensive hydrogeologic investigation and has implemented containment and cleanup measures.[75] (NM 05)[76]

Current New Mexico regulations prohibit use of unlined commercial disposal pits.

Damage to Ground Water from Inadequately Maintained Injection Wells

As in other States, New Mexico has experienced problems with injection wells.

A saltwater injection well, the BO-3, operated by Texaco, is used for produced water disposal for the Moore-Devonian oil field in southeastern New Mexico. Injection occurs at about 10,000 ft. The Ogallala aquifer, overlying the oil production formation, is the sole source of potable ground water in much of southeastern New Mexico. Dr. Daniel B. Stephens, Associate Professor of Hydrology at the New Mexico Institute of Mining and Technology, concluded that injection well BO-3 has contributed to a saltwater plume of contamination in the Ogallala aquifer. The plume is nearly 1 mile long and contains chloride concentrations of up to 26,000 ppm.

A local rancher sustained damage to crops after irrigating with water contaminated by this saltwater plume. In 1973, an irrigation well was completed satisfactorily on the ranch of Mr. Paul Hamilton, and, in 1977, the well began producing water with chlorides of 1,200 ppm. Mr. Hamilton's crops were severely damaged, resulting in heavy economic losses, and his farm property was foreclosed on. There is no evidence of crop damage from irrigation prior to 1977. Mr. Hamilton initiated a private law suit against Texaco for damages sustained to his ranch. Texaco argued that the saltwater plume was the result of leachate of brines from unlined brine disposal pits, now banned in the area. Dr. Stephens proved that if old pits in the vicinity,

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75 Comments in the Docket from BLM and the State of New Mexico pertain to NM 05. BLM states that the refinery upgradient from the subdivision is responsible for the contamination because of their "...extremely sloppy housekeeping practices..." which resulted in the loss of "...hundreds of thousands of gallons of refined product through leaks in their underground piping system." The Department of the Interior states that "There is, in fact, mounting evidence that the landfill and lagoons may have contributed little to the residential well contamination in the subdivisions." DOI states "...we strongly recommend that this case be deleted from the Damage Cases [Report to Congress]." "New Mexico states that "EID [Environmental Improvement Division] strongly believes that the Lee Acres Landfill has caused serious ground water contamination and is well worth inclusion in the Oil and Gas Damage Cases chapter of your [EPA] Report to Congress on Oil, Gas and Geothermal Wastes."

76 References for case cited: State of New Mexico Administrative Order No. 1005; contains water analysis for open pits, monitor wells, and impacted domestic wells. Motion-to-stay Order No. 1005. Denial of motion to stay. Newspaper articles. Southwest Research and Information Center, Response to Hearing before Water Quality Control Commission, 12/2/86. Letter to Dan Derkics, EPA, from Department of the Interior, refuting Lee Acres damage case, 8/11/87. Letter to Dan Derkics, EPA, from NMEID, refuting Department of the Interior letter of 8/11/87, dated 8/18/87. Letter to Dan Derkics, EPA, from Giant Refining Company, 8/20/87.

previously used for saltwater disposal, had caused the contamination, high chloride levels would have been detected in the irrigation well prior to 1977. Dr. Stephens also demonstrated that the BO-3 injection well had leaked some 20 million gallons of brine into the fresh ground water, causing chloride contamination of the Ogallala aquifer from which Mr. Hamilton drew his irrigation water. Based on this evidence a jury awarded Mr. Hamilton a cash settlement from Texaco for damages sustained both by the leaking injection well and by the abandoned disposal pits. The well has had workovers and additional pressure tests since 1978. The well is still in operation, in compliance with UIC regulations. (NM 01)[77]

Current UIC regulations require mechanical integrity testing every 5 years for all Class II wells.

The well in the above case was tested for mechanical integrity several times during the course of the trial, during which the plaintiff's hydrologist, after contacting the Texas Railroad Commission, discovered that this injection well would have been classed as a failed well using criteria established by the State of Texas for such tests. However, at the time, the well did not fail the test using criteria established by the State of New Mexico. Both States have primacy under the UIC program.

WEST COAST

The West Coast zone includes Washington, Oregon, and California. Of the three states, California has the most significant hydrocarbon production; Washington and Oregon have only minor oil and gas activity. Damage cases were collected only in California.

Operations

California has a diverse oil and gas industry, ranging from stripper production in very mature fields to deep exploration and large enhanced recovery operations. Southern California and the San Joaquin Valley are dominated by large capital- and energy-intensive enhanced recovery

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[77] References for case cited: Oil-Field Brine Contamination - A Case Study, Lea Co. New Mexico, from Selected Papers on Water Quality and Pollution in New Mexico - 1984; proceedings of a symposium, New Mexico Bureau of Mines and Resources.

projects, while the coastal fields are experiencing active exploration. California's most mature production areas are in the lower San Joaquin Valley and the Sacramento Basin. The San Joaquin produces both oil and gas. The Sacramento Valley produces mostly gas.

The average depth of new wells drilled in California in 1985 was 4,176 feet. Some 3,413 new wells were completed in 1985, 166 of which were exploratory.

Types of Operators

Operators in California range from small independents to major producers. The majors dominate capital- and energy-intensive projects, such as coastal development and large enhanced recovery projects. Independents tend to operate in the mature production areas dominated by stripper production.

Major Issues

Discharge of Produced Water and Oily Wastes to Ephemeral Streams

In the San Joaquin Valley, the State has long allowed discharge of oily high-chloride produced water to ephemeral streams. After discharge to ephemeral streams, the produced water is diverted into central sumps for disposal through evaporation and percolation. Infiltration of produced water into aquifers is assumed to occur, but official opinion on its potential for damage is divided. Some officials take the position that the aquifers are naturally brackish and thus have no beneficial use for agriculture or human consumption. A report by the Water Resources Control Board, however, suggests that produced water may percolate into useable ground-water structures.

For the purposes of this study conducted by Bean/Logan Consulting Geologists, ground water in the study area was categorized according to geotype and compared to produced water in sumps that came from production zones. Research was conducted on sumps in Cymric Valley, McKittrick Valley, Midway Valley, Elk Hills, Buena Vista Hills, and Buena Vista Valley production fields. While this recent research was not investigating ground-water damages per se, the study suggests obvious potential for damages relating to the ground water. The hydrogeologic analysis prepared for the California State Water Resources Control Board concludes that about 570,000 tons of salt from produced water were deposited in 1981 and that a total of 14.8 million tons have been deposited since 1900. The California Water Resources Board suspects that a portion of the salt has percolated into the ground water and has degraded it. In addition to suspected degradation of ground water, officers of the California Department of Fish and Game often find birds and animals entrapped in the oily deposits in the affected ephemeral streams. Exposure to the oily deposits often proves to be fatal to these birds and animals.[78] (CA 21)[79]

This is a permitted practice under current California regulations.

Aside from concerns over chronic degradation of ground water, this practice of discharge to ephemeral streams can cause damage to wildlife. The volume of wastes mixed with natural runoff sometimes exceeds the holding capacity of the ephemeral streams. The combined volume may then overflow the diversions to the sump areas and continue downstream, contaminating soil and endangering sensitive wildlife habitat. The oil and gas industry contends that it is rare for any wastes to pass the diversions set up to channel flow to the sumps, but the California Department of Fish and Game believes that it is a common occurrence.

Produced water from the Crocker Canyon area flows downstream to where it is diverted into Valley Waste Disposal's large unlined evaporation/percolation sumps for oil recovery (cooperatively operated by local oil producers). In one instance, discovery by California Fish and Game officials of a significant spill was made over a month after it occurred. According to the California State Water Quality Board, the incident was probably caused by heavy rainfall, as a consequence of which the volume of rain and waste exceeded the containment capacity of the disposal facility. The sumps became eroded, allowing oily waste to flow down the valley and into a wildlife habitat occupied by several endangered species including blunt-nosed leopard lizards, San Joaquin kit foxes, and giant kangaroo rats.

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78 API states that the California Regional Water Quality Board and EPA are presently deciding whether to promulgate additional permit requirements under the Clean Water Act and NPDES.

79 References for case cited: Lower Westside Water Quality Investigation Kern County, and Lower Westside Water Quality Investigation Kern County: Supplementary Report, Bean/Logan Consulting Geologists, 11/83; prepared for California State Water Resources Control Board. Westside Groundwater Study, Michael R. Rector, Inc., 11/83; prepared for Western Oil and Gas Association.

According to the State's report, there were 116 known wildlife losses including 11 giant kangaroo rats. The count of dead animals was estimated at only 20 percent of the actual number of animals destroyed because of the delay in finding the spill, allowing poisoned animals to leave the area before dying. Vegetation was covered with waste throughout the spill area. The California Department of Fish and Game does not believe this to be an isolated incident. The California Water Resources Control Board, during its investigation of the incident, noted "...deposits of older accumulated oil, thereby indicating that the same channel had been used for wastewater disposal conveyance in the past prior to the recent discharge. Cleanup activities conducted later revealed that buildup of older oil was significant." The companies implicated in this incident were fined $100,000 and were required to clean up the area. The companies denied responsibility for the discharge. (CA 08)[80]

This release was in violation of California regulations.

ALASKA

The Alaska zone includes Alaska and Hawaii. Hawaii has no oil or gas production. Alaska is second only to Texas in oil production.

Operations

Alaska's oil operations are divided into two entirely separate areas, the Kenai Peninsula (including the western shore of Cook Inlet) and the North Slope. Because of the areas' remoteness and harsh climate, operations in both areas are highly capital- and energy-intensive. For the purposes of damage case development, and indeed for most other types of analysis, operations in these two areas are distinct. Types of damages identified in the two areas have little in common.

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80 References for case cited: Report of Oil Spill in Buena Vista Valley, by Mike Glinzak, California Division of Oil and Gas (DOG), 3/6/86; map of site and photos accompany the report. Letters to Sun Exploration and Production Co. from DOG, 3/12 and 3/31/86. Newspaper articles in Bakersfield Californian, 3/8/86, 3/11/86, and undated. California Water Quality Control Board, Administrative Civil Liability Complaint #ACL-016, 8/8/86. California Water Quality Control Board, internal memoranda, Smith to Pfister concerning cleanup of site, 5/27/86; Smith to Nevins concerning description of damage and investigation, including map, 8/12/86. California Department of Fish and Game, Dead Endangered Species in a California Oil Spill, by Capt. E.A Simons and Lt. M. Akin, undated. Fact Sheets: Buena Vista Creek Oil Spill, Kern County, 3/7/86, and Mammals Occurring on Elk Hills and Buena Vista Hills, undated. Letter from Lt. Akin to EPA contractor, 2/24/87.

Activities on the Kenai Peninsula have been in progress since the late 1950s, and gas is the primary product. Production levels are modest as compared to those on the North Slope.

North Slope operations occur primarily in the Prudhoe Bay area, with some smaller fields located nearby. Oil is the primary product. Production has been under way since the trans-Alaska pipeline was completed in the mid 1970s. Much of the oil recovery in this area is now in the secondary phase, and enhanced recovery through water flooding is on the increase.

There were 100 wells drilled in the State in 1985, all of them on the North Slope. In 1985, one exploratory well was drilled in the National Petroleum Reserve - Alaska (NPRA) and two development wells were drilled on the Kenai Peninsula.

Types of Operators

There are no small, independent oil or gas operators in Alaska because of the high capital requirements for all activities in the region. Operators in the Kenai Peninsula include Union Oil of California and other major companies. Major producers on the North Slope are ARCO and Standard Alaska Production Company.

Major Issues

Reserve Pits, North Slope

Reserve pits on the North Slope are usually unlined and made of permeable native sands and gravels. Very large amounts of water flow in this area during breakup each spring in the phenomenon known as "sheet flow." Some of this water may unavoidably flow into and out of the reserve pits; however, the pits are designed to keep wastes in and keep surface waters out. Discharge of excess liquids from the pits directly onto the tundra is permitted under regulations of the Alaska Department of Environmental Conservation (ADEC) if discharge standards are met. (See summary on State rules and regulations.)

Through the processes of breakup and discharge, ADEC estimates that 100 million gallons of supernatant are pumped onto the tundra and roadways each year,[81] potentially carrying with it reserve pit constituents such as chromium, barium, chlorides, and oil. Scientists who have studied the area believe this has the potential to lead to bioaccumulation of heavy metals and other contaminants in local wildlife, thus affecting the food chain. However, no published studies that demonstrate this possibility exist. Results from preliminary studies suggest that the possibility exists for adverse impact to Arctic wildlife because of discharge of reserve pit supernatant to the tundra:

> In 1983, a study of the effects of reserve pit discharges on water quality and the macroinvertebrate community of tundra ponds was undertaken by the U. S. Fish and Wildlife Service in the Prudhoe Bay oil production area of the North Slope. Discharge to the tundra ponds is a common disposal method for reserve pit fluid in this area. The study shows a clear difference in water quality and biological measures among reserve pits, ponds receiving discharges from reserve pits (receiving ponds), distant ponds affected by discharges through surface water flow, and control ponds not affected by discharges. Ponds directly receiving discharges had significantly greater concentrations of chromium, arsenic, cadmium, nickel, and barium than did control ponds, and distant ponds showed significantly higher levels of chromium than did control ponds. Chromium levels in reserve pits and in ponds adjacent to drill sites may have exceeded EPA chronic toxicity criteria for protection of aquatic life. (AK 06)[82]

These discharges were permitted by the State of Alaska. No NPDES permits have been issued for these discharges. New Alaska regulations have more stringent effluent limits.

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81 Statement by Larry Dietrick to Carla Greathouse.

82 References for case cited: The Effects of Prudhoe Bay Reserve Pit Fluids on the Water Quality and Macroinvertebrates of Tundra Ponds, by Robin L. West and Elaine Snyder-Conn, Fairbanks Fish and Wildlife Enhancement Office, U.S. Fish and Wildlife Service, Fairbanks, Alaska, 9/87.

In the summer of 1985, a field method was developed by the U. S. Fish and Wildlife Service to evaluate toxicity of reserve pit fluids discharged into tundra wetlands at Prudhoe Bay, Alaska. Results of the study document acute toxicity effects of reserve pit fluids on Daphnia. Acute toxicity in Daphnia was observed after 96 hours of exposure to liquid in five reserve pits. Daphnia exposed to liquid in receiving ponds also had significantly higher death/immobilization than did Daphnia exposed to liquid in control ponds after 96 hours. At Drill Site 1, after 96 hours, 100 percent of the Daphnia introduced to the reserve pit had been immobilized or were dead, as compared to a control pond which showed less than 5 percent immobilized or dead after 96 hours. At Drill Site 12, 80 percent of the Daphnia exposed to the reserve pit liquid were dead or immobilized after 96 hours and less than 1 percent of Daphnia exposed to the control pond were dead or immobilized.[83] (AK 07)[84]

In June 1985, five drill sites and three control sites were chosen for studying the effects of drilling fluids and their discharge on fish and waterfowl habitat on the North Slope of Alaska. Bioaccumulation analysis was done on fish tissue using water samples collected from the reserve pits. Fecundity and growth were reduced in daphnids exposed for 42 days to liquid composed of 2.5 percent and 25 percent drilling fluid from the selected drill sites. Bioaccumulation of barium, titanium, iron, copper, and molybdenum was documented in fish exposed to drilling fluids for as little as 96 hours. (AK 08)[85]

Erosion of reserve pits and subsequent discharge of reserve pit contents to the tundra constitute another potential environmental problem on the North Slope. If exploration drilling pits are not closed out at the end of a drilling season, they may breach during "breakup." Reserve pit contaminants are then released directly to the tundra. (As described in Chapter III, <u>production</u> reserve pits are different from <u>exploration</u> reserve pits. Production reserve pits are designed to last for as long as 20 years.) A reserve pit wall may be poorly constructed or suffer structural damage during use; the wall may be breached by the hydrostatic head on the walls due to accumulation of precipitation and produced fluids. New exploration reserve pits are generally constructed below-grade. Flow of gravel during a pit breach can choke or cut off tundra streams, severely damaging or eliminating aquatic habitat.

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83 API comments in the Docket pertain to AK 07. API discusses the relevance of the Daphnia study to the damage cases.

84 References for case cited: An In Situ Acute Toxicity Test with Daphnia: A Promising Screening Tool for Field Biologists? by Elaine Snyder-Conn, U.S. Fish and Wildlife Service, Fish and Wildlife Enhancement, Fairbanks, Alaska, 1985.

85 References for case cited: Effects of Oil Drilling Fluids and Their Discharge on Fish and Waterfowl Habitat in Alaska, U.S. Fish and Wildlife Service, Columbia National Fishery Research Laboratory, Jackson Field Station, Jackson, Wyoming, February 1986.

The Awuna Test Well No. 1, which is 11,200 feet deep, is in the National Petroleum Reserve in Alaska (NPRA) and was a site selected for cleanup of the NPRA by the U.S. Geological Survey (USGS) in 1984. The site is in the northern foothills of the Brooks Range. The well was spud on February 29, 1980, and operations were completed on April 20,1981. A side of the reserve pit berm washed out into the tundra during spring breakup, allowing reserve pit fluid to flow onto the tundra. As documented by the USGS cleanup team, high levels of chromium, oil, and grease have leached into the soil downgradient from the pit. Chromium was found at 2.2 to 3.0 mg/kg dry weight. The high levels of oil and grease may be from the use of Arctic Pack (85 percent diesel fuel) at the well over the winter of 1980. The cleanup team noted that the downslope soils were discolored and putrefied, particularly in the upper layers. The pad is located in a runoff area allowing for erosion of pad and pit into surrounding tundra. A vegetation kill area caused by reserve pit fluid exposure is approximately equal to half an acre. Areas of the drill pad may remain barren for many years because of contamination of soil with salt and hydrocarbons. The well site is in a caribou calving area.[86] (AK 12)[87]

This type of reserve pit construction is no longer permitted under current Alaska regulations.

Waste Disposal on the North Slope

Inspection of oil and gas activities and enforcement of State regulations on the North Slope is difficult, as illustrated by the following case:

North Slope Salvage, Inc. (NSSI) operated a salvage business in Prudhoe Bay during 1982 and 1983. During this time, NSSI accepted delivery of various discarded materials from oil production companies on the North Slope, including more than 14,000 fifty-five gallon drums, 900 of which were full or held more than residual amounts of oils and chemicals used in the development and recovery of oil. The drums were stockpiled and managed by NSSI in a manner that allowed the discharge of hazardous substances. While the NSSI site may have stored chemicals and wastes from other operations that supported oil and gas exploration and production (e.g., vehicle maintenance materials), such storage would have constituted a very small percentage of NSSI's total inventory.

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86 API states that exploratory reserve pits must now be closed 1 year after cessation of drilling operations. EPA notes that it is important to distinguish between exploratory and production reserve pits. Production reserve pits are permanent structures that remain open as long as the well or group of wells is producing. This may be as long as 20 years.

87 References for case cited: Final Wellsite Cleanup on National Petroleum Reserve - Alaska, USGS, July 1986.

The situation was discovered by the Alaska Department of Environmental Conservation (ADEC) in June 1983. At this time, the State of Alaska requested Federal enforcement, but Federal action was never taken. An inadequate cleanup effort was mounted by NSSI after confrontation by ADEC. To preclude further discharges of hazardous substances, ARCO and Sohio paid for the cleanup because they were the primary contributors to the site. Cleanup was completed on August 5, 1983, after 58,000 gallons of chemicals and water were recovered. It is unknown how much of the hazardous substances was carried into the tundra. The discharge consisted of oil and a variety of organic substances known to be toxic, carcinogenic, mutagenic, or suspected of being carcinogenic or mutagenic.[88] (AK 10)[89]

Disposal of Drilling Wastes, Kenai Peninsula

Disposal of drilling wastes is the principal practice leading to potential environmental degradation on the Kenai Peninsula. The following cases involve centralized facilities, both commercial and privately run, for disposal of drilling wastes:

Operators of the Sterling Special Waste Site have had a long history of substandard monitoring, having failed during 1977 and 1978 to carry out any well sampling and otherwise having performed only irregular sampling. This was in violation of ADEC permit requirements to perform quarterly reports of water quality samples from the monitoring wells. An internal ADEC memo (L.G. Elphic to R.T. Williams, 2/25/76) noted "...we must not forget...that this is the State's first sanctioned hazardous waste site and as such must receive close observation during its initial operating period."[90]

A permit for the site was reissued by ADEC in 1979 despite knowledge by ADEC of lack of effective ground-water monitoring. In July of 1980, ADEC Engineer R. Williams visited the site and filed a report noting that the "...operation appears completely out of control." Monitoring well samples were analyzed by ADEC at this time and were found to be in excess of drinking water standards for iron, lead, cadmium, copper, zinc, arsenic, phenol, and oil and grease. One private water well in the vacinity showed 0.4 ppb 1,1,1-trichloroethane. The Sterling School well showed 2.1 g/L mercury. (Subsequent tests show mercury concentration below detection limits--0.001 mg/kg.) Both contamination incidents are alleged to be caused by the Sterling

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88 Alaska Department of Environmental Conservation (ADEC) states that this case "...is an example of how the oil industry inappropriately considered the limits of the exemption [under RCRA Section 3001]."

89 References for case cited: Report on the Occurrence, Discovery, and Cleanup of an Oil and Hazardous Substances Discharge at Lease Tract 57, Prudhoe Bay, Alaska, by Jeff Mach - ADEC, 1984. Letter to Dan Derkics, EPA, from Stan Hungerford, ADEC, 8/4/87.

90 The term "hazardous waste site" as used in this memo does not refer to a "RCRA Subtitle C hazardous waste site."

Special Waste Site. Allegations are unconfirmed by the ADEC. (AK 03)[91]

Practices at the Sterling site were in violation of the permit.

This case involves a 45-acre gravel pit on Poppy Lane on the Kenai Peninsula used since the 1970s for disposal of wastes associated with gas development. The gravel pit contains barrels of unidentified wastes, drilling muds, gas condensate, gas condensate-contaminated peat, abandoned equipment, and soil contaminated with diesel and chemicals. The property belongs to Union Oil Co., which bought it around 1968. Dumping of wastes in this area is illegal; reports of last observed dumping were in October 1985, as witnessed by residents in the area. In this case, there has been demonstrated contamination of adjacent water wells with organic compounds related to gas condensate (ADEC laboratory reports from October 1986 and earlier). Alleged health effects on residents of neighboring properties include nausea, diarrhea, rashes, and elevated levels of metals (chromium, copper) in blood in two residents. Property values have been effectively reduced to zero for residential resale. A fire on the site on July 8, 1981, was attributed to combustion of petroleum-related products, and the fire department was unable to extinguish it. The fire was allegedly set by people illegally disposing of wastes in the pit. Fumes from organic liquids are noticeable in the breathing zone onsite. UNOCAL has been directed on several occasions to remove gas condensate in wastes from the site. Since June 19, 1972, disposal of wastes regulated as solid wastes has been illegal at this site. The case has been actively under review by the State since 1981. (AK 01)[92]

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91 References for case cited: Dames and Moore well monitoring report, showing elevated metals referenced above, October 1976. Dowling Rice & Associates monitoring results, 1/15/80, and Mar Enterprises monitoring results, September 1980, provided by Walt Pederson, showing elevated levels of metals, oil, and grease in ground water. Detailed letter from Eric Meyers to Glen Aikens, Deputy Commissioner, ADEC, recounting permit history of site and failure to conduct proper monitoring, 1/22/82. Testimony and transcripts from Walt Pederson on public forums complaining about damage to drinking water and mismanagement of site. Transcripts of waste logs of site from 9/1/79 to 8/20/84, indicating only 264,436 bbl of muds received, during a period that should have generated much more waste. Letter from Howard Keiser to Union Oil, 12/7/81, indicating that "...drilling mud is being disposed of by methods other than at the Sterling Special Waste Site and by methods that could possibly cause contamination of the ground water."

92 References for case cited: Photos showing illegal dumping in progress. Field investigations. State of Alaska Individual Fire Report on "petroleum dump," 7/12/81. File memo on site visit by Howard Keiser, ADEC Environmental Field Officer, in response to a complaint by State Forestry Officer, 7/21/81. Memo from Howard Keiser to Bob Martin on his objections to granting a permit to Union Oil for use of site as disposal site on basis of impairment of wildlife resources, 7/28/83. Letter, ADEC to Union Oil, objecting to lack of cleanup of site despite notification by ADEC on 10/3/84. Analytical reports by ADEC indicating gas condensate contamination on site, 8/14/84. EPA Potential Hazardous Waste Site Identification, indicating continued dumping as of 8/10/85. Citizens' complaint records. Blood test indicating elevated chromium for neighboring resident Jessica Black, 1/16/85. Letter to Mike Lucky of ADEC from Union Oil confirming cleanup steps, 2/12/85. Memo by Carl Reller, ADEC ecologist, indicating presence of significant toxics on site, 8/14/85. Minutes of Waste Disposal Commission meeting, 2/10/85. ADEC analytic reports indicating gas condensate at site, 10/10/85. Letters from four different real estate firms in area confirming inability to sell residential property in Poppy Lane area. Letter from Bill Lamoreaux, ADEC, to J. Black and R. Sizemore referencing high selenium/chromium in the ground water in the area. Miscellaneous technical documents. EPA Potential Hazardous Waste Site Preliminary Assessment, 2/12/87.

These activities are illegal under current Alaska regulations.

MISCELLANEOUS ISSUES

Improperly Abandoned and Improperly Plugged Wells

Degradation of ground water from improperly plugged and unplugged wells is known to occur in Kansas, Texas, and Louisiana. Improperly plugged and unplugged wells enable native brine to migrate up the wellbore and into freshwater aquifers. The damage sustained can be extensive.

Problems also occur when unidentified improperly plugged wells are present in areas being developed as secondary recovery projects. After the formation has been pressurized for secondary recovery, native brine can migrate up unplugged or improperly plugged wells, potentially causing extensive ground-water contamination with chlorides.

In 1961, Gulf and its predecessors began secondary recovery operations in the East Gladys Unit in Sedgwick County, Kansas. During secondary recovery, water is pumped into a target formation at high pressure, enhancing oil production. This pumping of water pressurizes the formation, which can at times result in brines being forced up to the surface through unplugged or improperly plugged abandoned wells. When Gulf began their secondary recovery in this area, it was with the knowledge that a number of abandoned wells existed and could lead to escape of salt water into fresh ground water.

Gerald Blood alleged that three improperly plugged wells in proximity to the Gladys unit were the source of fresh ground-water contamination on his property. Mr. Blood runs a peach orchard in the area. Apparently native brine had migrated from the nearby abandoned wells into the fresh ground water from which Mr. Blood draws water for domestic and irrigation purposes. Contamination of irrigation wells was first noted by Mr. Blood when, in 1970, one of his truck gardens was killed by irrigation with salty water. Brine migration contaminated two more irrigation wells in the mid-1970s. By 1980, brine had contaminated the irrigation wells used to irrigate a whole section of Mr. Blood's land. By this time, adjacent landowners also had contaminated wells. Mr. Blood lost a number of peach trees as a result of the contamination of his irrigation well; he also lost the use of his domestic well.

The Bloods sued Gulf Oil in civil court for damages sustained by their farm from chloride contamination of their irrigation and residential wells. The Bloods won their case and were awarded an undisclosed amount of money.[93] (KS 14)[94]

Current UIC regulations prohibit contamination of groundwater.

The potential for environmental damage through ground-water degradation is high, given the thousands of wells abandoned throughout the country prior to any State regulatory plugging requirements.

In West Texas, thousands of oil and gas wells have been drilled over the last several decades, many of which were never properly plugged. There exists in the subsurface of this area a geologic formation known as the Coleman Junction, which contains extremely salty native brine and possesses natural artesian properties. Since this formation is relatively shallow, most oil and gas wells penetrate this formation. If an abandoned well is not properly plugged, the brine contained in the Coleman Junction is under enough natural pressure to rise through the improperly plugged well and to the surface.

According to scientific data developed over several years, and presented by Mr. Ralph Hoelscher, the ground water in and around San Angelo, Texas, has been severely degraded by this seepage of native brine, and much of the agricultural land has absorbed enough salt as to be nonproductive. This situation has created a hardship for farmers in the area. The Texas Railroad Commission states that soil and ground water are contaminated with chlorides because of terracing and fertilizing of the land. According to Mr. Hoelscher, a long-time farmer in the area, little or no fertilizer is used in local agriculture. (TX 11)[95]

Improper abandonment of oil and gas wells is prohibited in the State of Texas.

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93 API states that damage in this case was brought about by "old injection practices."

94 References for case cited: U.S. District Court for the district of Kansas, Memorandum and Order, Blood vs. Gulf; Response to Defendants' Statement of Uncontroverted Facts; and Memorandum in Opposition to Motion for Summary Judgment. Means Laboratories, Inc., water sample results. Department of Health, District Office #14, water samples results. Extensive miscellaneous memoranda, letters, analysis.

95 References for case cited: Water analysis of Ralph Hoelscher's domestic well. Soil Salinity Analysis, Texas Agricultural Extension Service - The Texas A&M University System, Soil Testing Laboratory, Lubbock, Texas 79401. Photographs. Conversation with Wayne Farrell, San Angelo Health Department. Conversation with Ralph Hoelscher, resident and farmer.

CHAPTER V

RISK MODELING

INTRODUCTION

This chapter summarizes the methods and results of a risk analysis of certain wastes associated with the onshore exploration, development, and production of crude oil and natural gas. The risk analysis relies heavily on the information developed by EPA on the types, amounts, and characteristics of wastes generated (summarized in Chapter II) and on waste management practices (summarized in Chapter III). In addition, this quantitative modeling analysis was intended to complement EPA's damage case assessment (Chapter IV). Because the scope of the model effort was limited, some of the types of damage cases reported in Chapter IV are not addressed here. On the other hand, the risk modeling of ground-water pathways covers the potential for certain more subtle or long-term risks that might not be evidenced in the contemporary damage case files. The methods and results of the risk analysis are documented in detail in a supporting EPA technical report (USEPA 1987a).

EPA's risk modeling study estimated releases of contaminants from selected oil and gas wastes into ground and surface waters, modeled fate and transport of these contaminants, and estimated potential exposures, health risks, and environmental impacts over a 200-year modeling period. The study was not designed to estimate absolute levels of national or regional risks, but rather to investigate and compare potential risks under a wide variety of conditions.

Objectives

The main objectives of the risk analysis were to (1) characterize and classify the major risk-influencing factors (e.g., waste types, waste management practices, environmental settings) associated with current operations at oil and gas facilities;[1] (2) estimate distributions of major risk-influencing factors across the population of oil and gas facilities within various geographic zones; (3) evaluate these factors in terms of their relative effect on risks; and (4) develop, for different geographic zones of the U.S., initial quantitative estimates of the possible range of baseline health and environmental risks for the variety of existing conditions.

Scope and Limitations

The major portion of this risk study involved a predictive quantitative modeling analysis focusing on large-volume exempt wastes managed according to generally prevailing industry practices. EPA also examined (but did not attempt quantitative assessment of) the potential effects of oil and gas wastes on the North Slope of Alaska, and reviewed the locations of oil and gas activities relative to certain environments of special interest, including endangered species habitats, wetlands, and public lands.

Specifically, the quantitative risk modeling analysis estimated long-term human health and environmental risks associated with the disposal of drilling wastes in onsite reserve pits, the deep well injection of produced water, and the direct discharge of produced water from stripper wells to surface waters. These wastes and waste management practices encompass the major waste streams and the most common management practices within the scope of this report, but they are not necessarily those giving rise to the most severe or largest number of damage cases of the types presented in Chapter IV. For risk modeling purposes, EPA generally assumed full compliance with applicable current State and

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1 References in this chapter to oil and gas facilities, sites, or activities refer to exploration, development, and production operations.

Federal regulations for the practices studied. Risks were not modeled for a wide variety of conditions or situations, either permitted or illegal, that could give rise to damage incidents, such as waste spills, land application of pit or water wastes, discharge of produced salt water to evaporation/percolation pits, or migration of injected wastes through unplugged boreholes.

In this study, EPA analyzed the possible effects of selected waste streams and management practices by estimating risks for model scenarios. Model scenarios are defined as hypothetical (but realistic) combinations of variables representing waste streams, management practices, and environmental settings at oil and gas facilities. The scenarios used in this study were, to the extent possible, based on the range of conditions that exist at actual sites across the U.S. EPA developed and analyzed more than 3,000 model scenarios as part of this analysis.

EPA also estimated the geographic and waste practice frequencies of occurrence of the model scenarios to account for how well they represent actual industry conditions and to account for important variations in oil and gas operations across different geographic zones of the U.S.[2] These frequencies were used to weight the model results, that is, to account for the fact that some scenarios represent more sites than others. However, even the weighted risk estimates should not be interpreted as absolute risks for real facilities because certain major risk-influencing factors were not modeled as variables and because the frequency of occurrence of failure/release modes and concentrations of toxic constituents were not available.

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2 The 12 zones used in the risk assessment are identical to the zones used as part of EPA's waste sampling and analysis study (see Chapter II), with one exception: zone 11 (Alaska) was divided into zone 11A representing the North Slope and zone 11B representing the Cook Inlet-Kenai Peninsula area.

A principal limitation of the risk analysis is that EPA had only a relatively small sample set of waste constituent concentration data for the waste streams under study. As a result, the Agency was unable to construct regional estimates of toxic constituent concentrations or a national frequency distribution of concentrations that could be directly related to other key geophysical or waste management variables in the study. Partly because of this data limitation, all model scenarios defined for this study were analyzed under two different sets of assumptions: a "best-estimate"[3] set of assumptions and a "conservative" set of assumptions. The best-estimate and conservative sets of assumptions are distinguished by different waste constituent concentrations, different timing for releases of drilling waste and produced water, and, in some cases, different release rates (see the later sections on model scenarios and model procedures for more detail). The best-estimate assumptions represent a set of conditions which, in EPA's judgment, best characterize the industry as a whole, while the conservative assumptions define higher-risk (but not worst-case) conditions. It is important to clarify that the best-estimate and conservative assumptions are not necessarily based on a comprehensive statistical analysis of the frequency of occurrence or absolute range of conditions that exist across the industry; instead, they reflect EPA's best judgment of a reasonable range of conditions based on available data analyzed for this study.

Another major limitation of the study is the general absence of empirical information on the frequency, extent, and duration of waste releases from the oil and gas field management practices under consideration. As described below, this study used available engineering judgments regarding the nature of a variety of failure/release mechanisms for waste pits and injection wells, but no assumptions were made

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3 As used here, the term best estimate is different from the statistical concept of maximum likelihood (i.e., best) estimate.

regarding the relative frequency or probability of occurrence of such failures.

Although EPA believes that the scenarios analyzed are realistic and representative, the risk modeling for both sets of scenarios incorporated certain assumptions that tend to overestimate risk values. For example, for the health risk estimates it was assumed that individuals ingest untreated contaminated water over a lifetime, even if contaminant concentrations were to exceed concentrations at which an odor or taste is detectable. In addition, ingested concentrations were assumed to equal the estimated center line (i.e., highest) concentration in the contaminant plume.

Other features of the study tend to result in underestimation of risk. For example, the analysis focuses on risks associated with drilling or production at single oil or gas wells, rather than on the risks associated with multiple wells clustered in a field, which could result in greater risks and impacts because of overlapping effects. Also, the analysis does not account for natural or other source background levels of chemical constituents which, when combined with the contamination levels from oil and gas activities, could result in increased risk levels.

QUANTITATIVE RISK ASSESSMENT METHODOLOGY

EPA conducted the quantitative risk assessment through a four-step process (see Figure V-1). The first three steps--collection of input data, specification of model scenarios, and development of modeling procedures--are described in the following subsections. The last step, estimation of effects, is described in subsequent sections of this chapter that address the quantitative modeling results.

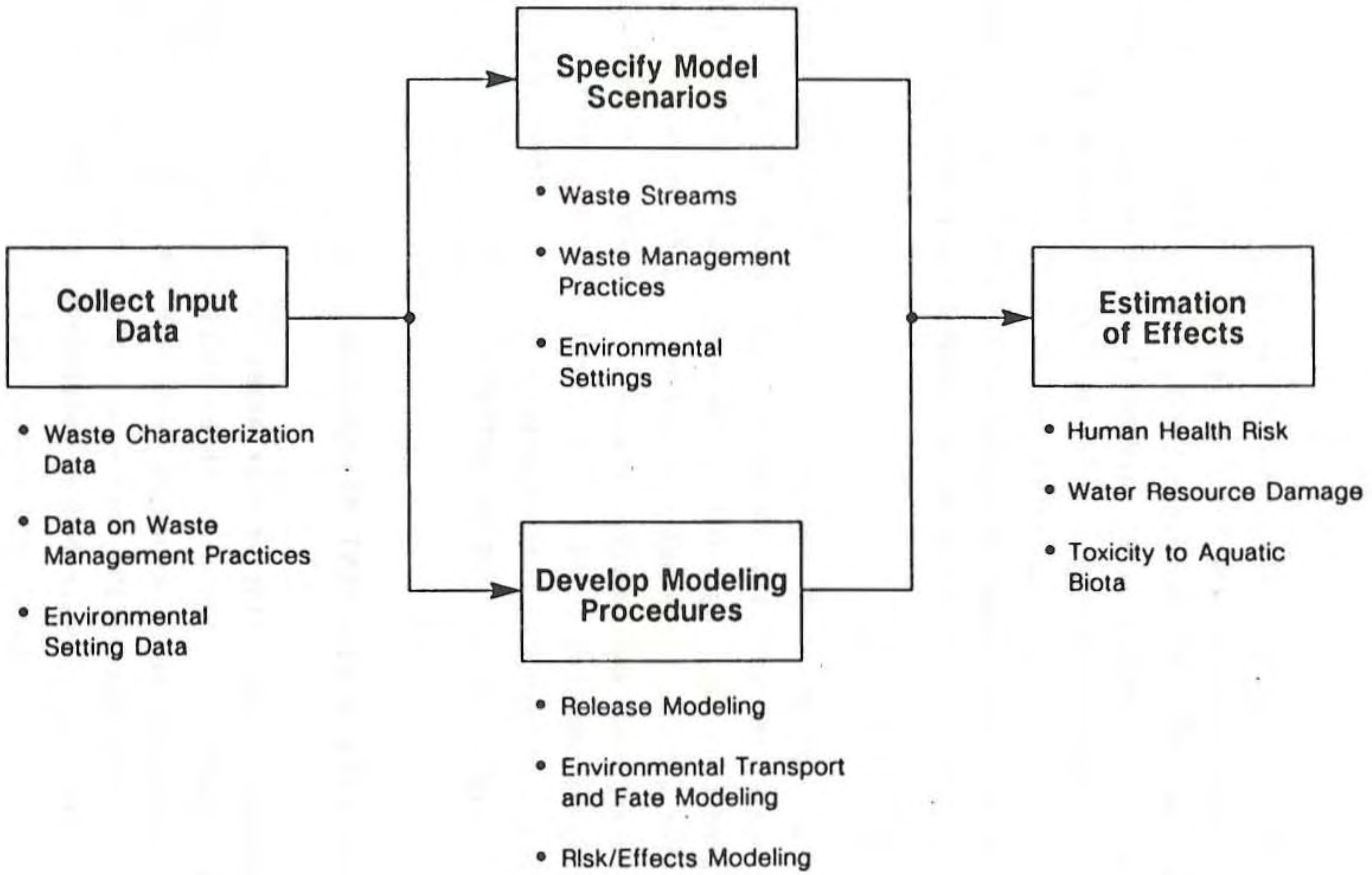

Figure V-1 Overview of Quantitative Risk Assessment Methodology

Input Data

EPA collected three main categories of input data for the quantitative modeling: data on waste volumes and constituents, waste management practices, and environmental settings. Data on waste volumes were obtained from EPA's own research on sources and volumes of wastes, supplemented by the results of a survey of oil and gas facilities conducted by the American Petroleum Institute (API) (see Chapter II). Data on waste constituents were obtained from EPA's waste stream chemical analysis study. The results of EPA's research on current waste management practices, supplemented by API's studies (see Chapter III), were the basis for defining necessary input parameters concerning waste management practices. Data needed to characterize environmental settings were obtained from an analysis of conditions at 266 actual drilling and production locations sampled from areas with high levels of oil and gas activity (see USEPA 1987a, Chapter 3, for more detail on the sample selection and analytical methods).

Model Scenarios

The model scenarios in this analysis are unique combinations of the variables used to define waste streams, waste management practices, and environmental settings at oil and gas facilities. Although the model scenarios are hypothetical, they were designed to be:

- Representative of actual industry conditions (they were developed using actual industry data, to the extent available);
- Broad in scope, covering prevalent industry characteristics but not necessarily all sets of conditions that occur in the industry; and
- Sensitive to major differences in environmental conditions (such as rainfall, depth to ground water, and ground-water flow rate) across various geographic zones of the U.S.

As illustrated in Figure V-2, EPA decided to focus the quantitative analysis on the human health and environmental risks associated with three types of environmental releases: leaching of drilling waste chemical constituents from onsite reserve pits to ground water below the pits (drilling sites); release of produced water chemical constituents from underground injection wells to surface aquifers[4] (production sites); and direct discharge of produced water chemical constituents to streams and rivers (stripper well production sites).

Chemical Constituents

EPA used its waste sampling and analysis data (described in Chapter II) to characterize drilling wastes and produced water for quantitative risk modeling. Based on the available data, EPA could not develop separate waste stream characterizations for various geographic zones; one set of waste characteristics was used to represent the nation. The model drilling waste represents only water-based drilling muds (not oil-based muds or wastes from air drilling), which are by far the most prevalent drilling mud type. Also, the model drilling waste does not represent one specific process waste, but rather the combined wastes associated with well drilling that generally are disposed of in reserve pits.

For both drilling wastes and produced water, EPA used a systematic methodology to select the chemical constituents of waste streams likely to dominate risk estimates (see USEPA 1987a, Chapter 3, for a detailed description of this methodology). The major factors considered in the chemical selection process were (1) median and maximum concentrations in

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[4] For the purpose of this report, a surface aquifer is defined as the geologic unit nearest the land surface that transmits sufficient quantities of ground water to be used as a source of drinking water. It is distinguished from aquifers at greater depths, which may be the injection zone for an underground injection well or are too deep to be generally used as a drinking water source.

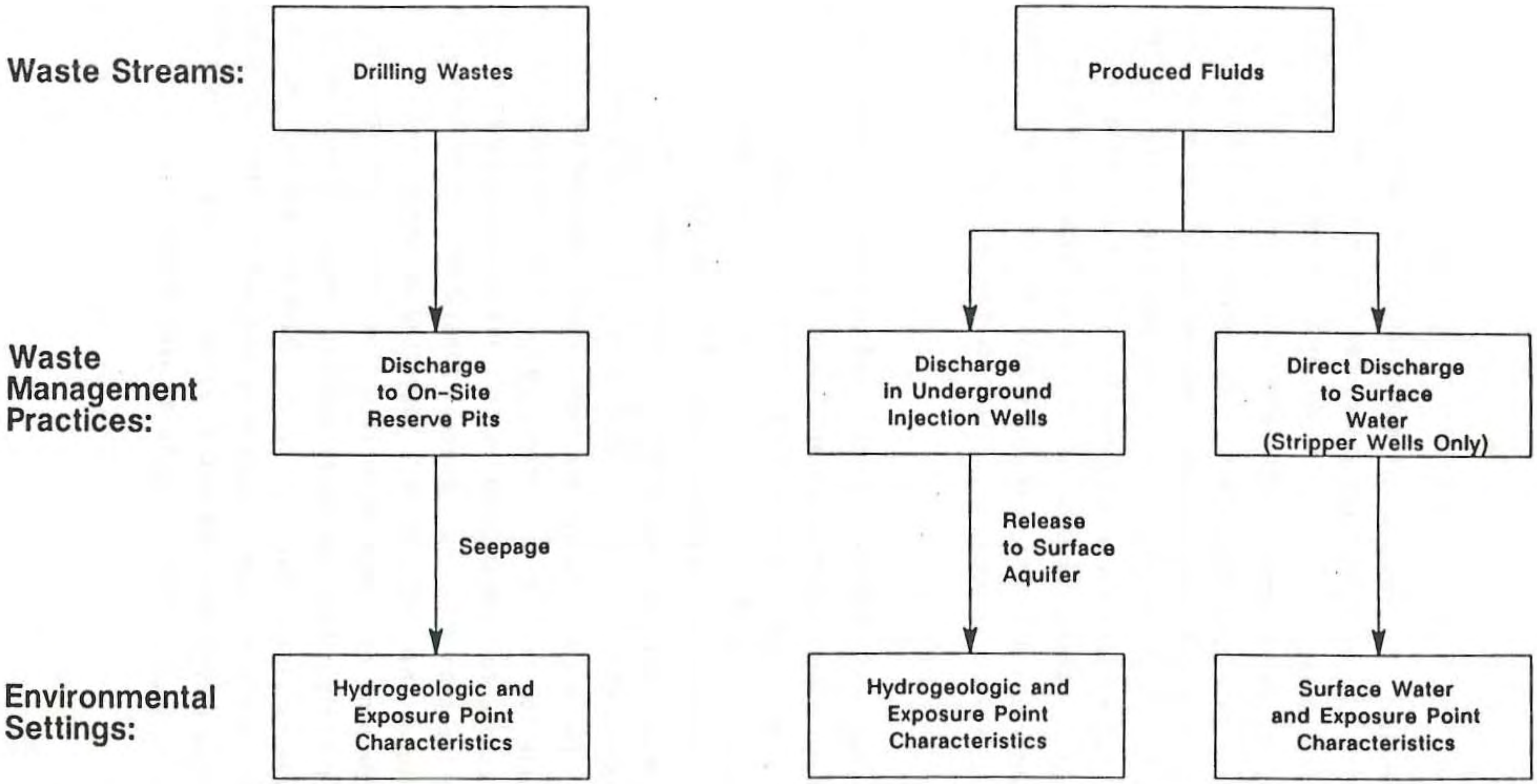

Figure V-2 Overview of Modeling Scenarios Considered in the Quantitative Risk Assessment

the waste samples; (2) frequency of detection in the waste samples; (3) mobility in ground water; and (4) concentrations at which human health effects, aquatic toxicity, or resource damage start to occur. Through this screening process, EPA selected six chemicals for each waste type that were likely to dominate risk estimates in the scenarios modeled. For each selected chemical, two concentrations were determined from the waste characterization data. The 50th percentile (median) was used to set constituent concentrations for a "best-estimate" waste characterization, while the 90th percentile was used for a "conservative" waste characterization. The selected chemicals and concentrations, shown in Table V-1, served as model waste streams for the quantitative risk analysis.

Of the chemicals selected, arsenic and benzene were modeled as potential carcinogens. Both substances are rated as Group A in EPA's weight-of-evidence rating system (i.e., sufficient evidence of carcinogenicity in humans). Some scientists, however, believe that arsenic may not be carcinogenic and may be a necessary element at low levels. Sodium, cadmium, and chromium VI were modeled for noncarcinogenic effects. The critical (i.e., most sensitive) health effects for these constituents are hypertension for sodium and liver and kidney damage for cadmium and chromium VI. It is emphasized that the effect threshold for sodium used in this analysis was based on potential effects in the high-risk (not general) population. (The level used is slightly higher than EPA's 20 mg/L suggested guidance level for drinking water.) The high-risk population is defined to include individuals with a genetic predisposition for hypertension, pregnant women, and hypertensive patients. Finally, boron, chloride, sodium, cadmium, chromium VI, and total mobile ions were modeled for their potential aquatic toxicity and resource damage effects. Table V-2 lists the cancer potency factors and effects thresholds used in the study.

Table V-1 Model Constituents and Concentrations[a]

Produced water constituents	Concentrations Median (mg/L)	Upper 90% (mg/L)
Arsenic	0.02	1.7
Benzene	0.47	2.9
Boron	9.9	120
Sodium	9,400	67,000
Chloride	7,300	35,000
Mobile ions[b]	23,000	110,000

Drilling waste (water-based) constituents	Pit liquids Median (mg/L)	Pit liquids Upper 90% (mg/L)	Pit solids/TCLP[c] Median (mg/L)	Pit solids/TCLP[c] Upper 90% (mg/L)	Pit solids/direct Median (mg/kg)	Pit solids/direct Upper 90% (mg/kg)
Arsenic	0.0	0.16	0.0	0.002[d]	0.0	0.010
Cadmium	0.056	1.4	0.011	0.29	2.0	5.4
Sodium	6,700	44,000	1,200[e]	4,400[e]	8,500	59,000
Chloride	3,500	39,000	2,000[f]	11,000[f]	17,000	88,000
Chromium VI	0.43	290	0	0.78	22	190
Mobile ions[b]	17,000	95,000	4,000	16,000	100,000	250,000

[a]The median constituent concentrations from the relevant samples in the EPA waste sampling/analysis study were used for a "best-estimate" waste characterization, and the 90th percentile concentrations were used for a "conservative" waste characterization (data source: USEPA 1987b).

[b]Mobile ions include chloride, sodium, potassium, calcium, magnesium, and sulfate.

[c]TCLP = toxicity characteristic leaching procedure.

[d]Upper 90th percentile arsenic values estimated based on detection limit.

[e]Preliminary examinations indicate that the sodium TCLP values may overestimate the actual leachable sodium concentrations in reserve pit samples. The accuracy of these concentrations is the subject of an ongoing evaluation.

[f]Chloride TCLP values are estimated based on sodium data.

Table V-2 Toxicity Parameters and Effects Thresholds[a]

Model constituent	Cancer potency factor $(mg/kd\text{-}d)^{-1}$	Human noncancer threshold (mg/kg-d)	Aquatic toxicity threshold (mg/L)	Resource damage threshold (mg/L)
Benzene	0.052	NA	NA[b]	NA
Arsenic	15	NA	NA	NA
Sodium	NA	0.66	83.4	NA
Cadmium	NA[c]	0.00029	0.00066	NA
Chromium VI	NA[c]	0.005	0.011	NA
Chloride	NA	NA	NA	250
Boron	NA	NA	NA	1
Total mobile ions[d]	NA	NA	NA	335[e] 500[f]

[a]See USEPA 1987a for detailed description and documentation.

[b]NA = not applicable; indicates that an effect type was not modeled for a specific chemical.

[c]Not considered carcinogenic by the oral exposure route.

[d]Represents total mass of ions mobile in ground water.

[e]For surface water only (assumes a background level of 65 mg/L and a threshold limit of 400 mg/L).

[f]For ground water only.

The chemicals selected for risk modeling differ from the constituents of potential concern identified in Chapter II for at least three important reasons. First, the analysis in Chapter II considers the hazards of the waste stream itself but, unlike the selection process used for this risk analysis, does not consider the potential for waste constituents to migrate through ground water and result in exposures at distant locations. Second, certain constituents were selected based on their potential to cause adverse environmental (as opposed to human health) effects, while the analysis in Chapter II considers only human health effects. Third, frequency of detection was considered in selecting constituents for the risk modeling but was not considered in the Chapter II analysis.

Waste Management Practices

Three general waste management practices were considered in this study: onsite reserve pits for drilling waste; underground injection wells for produced water; and direct discharge of produced water to rivers and streams (for stripper wells only).[5] EPA considered the underground injection of produced water in disposal wells and waterflooding wells.[6] The design characteristics and parameter values modeled for the different waste management practices are presented in Tables V-3 and V-4. These values were developed from an evaluation of EPA's and API's waste volume data (see Chapter II) and waste management practice survey results (see Chapter III) for the nation as a whole.

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[5] At present, there are no Federal effluent guidelines for stripper wells (i.e., oil wells producing less than ten barrels of crude oil per day), and, under Federal law, these wells are allowed to discharge directly to surface waters subject to certain restrictions. Most other onshore oil and gas facilities are subject to the Federal zero-discharge requirement.

[6] Waterflooding is a secondary recovery method in which treated fresh water, seawater, or produced water is injected into a petroleum-bearing formation to help maintain pressure and to displace a portion of the remaining crude oil toward production wells. Injection wells used for waterflooding may have different designs, operating practices, and economic considerations than those of disposal wells, which are used simply to dispose of unwanted fluid underground.

Table V-3 Drilling Pit Waste (Water-Based) Management Practices

Onsite pit size	Waste amount[a] (barrels)	Disposal practice	Pit dimensions(m) L	W	D
Large	26,000	Reserve pit-unlined	59	47	2.3[b]
		Reserve pit-lined, capped			
Medium	5,900	Reserve pit-unlined	32	25	2.0[b]
		Reserve pit-lined, capped			
Small	1,650	Reserve pit-unlined	17	14	1.9[b]
		Reserve pit-lined, capped			

[a]Per well drilled (includes solids and liquids).

[b]Waste depths for large, medium, and small pits were 1.5, 1.2, and 1.1 meters, respectively.

Table V-6 Definition of Best-Estimate and Conservative Release Assumptions

Release source	Release assumption	Constituent concentration in waste[a]	Failure/release timing	Release volume
Unlined Pits	Best-estimate	50th % (median)	Release begins in year 1	Calculated by release equations
	Conservative	90th %	Release begins in year 1	Calculated by release equations (same as best-estimate)
Lined Pits	Best-estimate	50th %	Liner failure begins in year 25	Calculated by release equations
	Conservative	90th %	Liner failure begins in year 5	Calculated by release equations (same as best-estimate)
Injection Wells/ Casing Failure	Best-estimate	50th %	One year release in year 1 for waterflood wells; constant annual releases during years 11-13 for disposal wells	0.2-96 bbl/d for waterflood wells; 0.05-38 bbl/d for disposal wells
	Conservative	90th %	Constant annual releases during years 11-15 for waterflood and disposal wells	Same as best-estimate
Injection Wells/ Grout Seal Failure	Best-estimate	50th %	Constant annual releases during years 11-15 for waterflood and disposal wells	0.00025-0.0025 bbl/d for waterflood wells; 0.00025-0.0075 bbl/d for disposal wells
	Conservative	90th %	Constant annual releases during years 1-20 for waterflood and disposal wells (immediate failure, no detection)	0.05-0.5 bbl/d for waterflood wells; 0.05-1.5 bbl/d for disposal wells

[a]See Table V-1.

the same layers considered during the active period. For unlined pits, release was assumed to begin immediately at the start of the modeling period. For lined pits, failure (i.e., increase in hydraulic conductivity of the liner) was assumed to occur either 5 or 25 years after the start of the modeling period. It was assumed that any liquids remaining in unlined reserve pits at the time of closure would be land applied adjacent to the pit. Liquids remaining in lined pits were assumed to be disposed offsite.

For modeling releases to surface aquifers from Class II injection wells, a 20-year injection well operating period was assumed, and two failure mechanisms were studied: (1) failure of the well casing (e.g., a corrosion hole) and (2) failure of the grout seal separating the injection zone from the surface aquifer. At this time, the Agency lacks the data necessary to estimate the probability of casing or grout seal failures occurring. A well casing failure assumes that injected fluids are exiting the well through a hole in the casing protecting the surface aquifer. In most cases, at least two strings of casing protect the surface aquifer and, in those cases, a release to this aquifer would be highly unlikely. The Agency has made exhaustive investigations of Class I well (i.e., hazardous waste disposal well) failures and has found no evidence of release of injected fluids through two strings of casing. However, the Agency is aware that some Class II wells were constructed with only one string of casing; therefore, the scenarios modeled fall within the realm of possible failures. Since integrity of the casing must be tested every 5 years under current EPA guidelines (more frequently by some States), EPA assumed for the conservative scenarios that a release would begin on the first day after the test and would last until the next test (i.e., 5 years). For the best-estimate scenarios, EPA assumed that the release lasted 1 year (the minimum feasible modeling period) in the case of waterflood wells and 3 years in the case of disposal wells, on the supposition that shorter release durations would be more likely for waterflooding where injection flow rates and volumes are important economic considerations for the operation. EPA also assumed here that the release flow from a failed well would remain constant over the duration of the failure. This simplifying assumption is more likely to hold in low-pressure wells than in the high-pressure wells more typical of waterflooding operations. In high-pressure wells the high flow rate would likely enlarge the casing holes more rapidly, resulting in more injection fluid escaping into the wrong horizon and a noticeable drop of pressure in the reservoir.

For the grout seal type of failure, EPA estimated for conservative modeling purposes that the failure could last for 20 years (i.e., as long as the well operates). This is not an unreasonable worst-case assumption because the current regulations allow the use of cementing records to determine adequacy of the cement job, rather than actual testing through the use of logs. If the cementing records were flawed at the outset, a cementing failure might remain undetected. As part of its review of the Underground Injection Control (UIC) regulations, the Agency is considering requiring more reliable testing of the cementing of wells, which would considerably lessen the likelihood of such scenarios. For an alternative best-estimate scenario, the Agency assumed a 5-year duration of failure as a more typical possibility.

Because of a lack of both data and adequate modeling methods, other potentially important migration pathways by which underground injection of waste could contaminate surface aquifers (e.g., upward contaminant migration from the injection zone through fractures/faults in confining layers or abandoned boreholes) were not modeled.

Chemical transport was modeled for ground water and surface water (rivers). Ground-water flow and mass transport were modeled using EPA's Liner Location Risk and Cost Analysis Model (LLM) (USEPA 1986). The LLM uses a series of predetermined flow field types to define ground-water conditions (see Table V-7); a transient-source, one-dimensional, wetting-front model to assess unsaturated zone transport; and a modified version of the Random Walk Solute Transport Model (Prickett et al. 1981) to predict ground-water flow and chemical transport in the saturated zone. All ground-water exposure and risk estimates presented in this report are for the downgradient center line plume concentration. Chemical transport in rivers was modeled using equations adapted from EPA (USEPA 1984a); these equations can account for dilution, dispersion, particulate adsorption, sedimentation, degradation (photolysis, hydrolysis, and biodegradation), and volatilization.

EPA used the LLM risk submodel to estimate cancer and chronic noncancer risks from the ingestion of contaminated ground and surface water. The measure used for cancer risk was the maximum (over the 200-year modeling period) lifetime excess[7] individual risk, assuming an individual ingested contaminated ground or surface water over an entire lifetime (assumed to be 70 years). These risk numbers represent the estimated probability of occurrence of cancer in an exposed individual. For example, a cancer risk estimate of 1×10^{-6} indicates that the chance of an individual getting cancer is approximately one in a million over a 70-year lifetime. The measure used for noncancer risk was the maximum (over the 200-year modeling period) ratio of the estimated chemical dose to the dose of the chemical at which health effects begin to occur (i.e., the threshold dose). Ratios exceeding 1.0 indicate the potential for adverse effects in some exposed individuals; ratios less than 1.0 indicate a very low likelihood of effect (assuming that background exposure is zero, as is done in this study). Although these ratios are <u>not</u> probabilities, higher ratios in general are cause for greater concern.

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7 Excess refers to the risk increment attributable only to exposure resulting from the releases considered in this analysis. Background exposures were assumed to be zero.

Table V-7 Definition of Flow Fields Used in Ground-Water Transport Modeling

Flow field	Key variables defining flow field[a]	
	Aquifer configuration[b]	Horizontal ground-water velocity
A	Unconfined aquifer	1 m/yr
B	Unconfined aquifer	10 m/yr
C	Unconfined aquifer	100 m/yr
D	Unconfined aquifer	1,000 m/yr
E	Unconfined aquifer	10,000 m/yr
F	Confined aquifer	0.05 m/yr in the confining layer and 100 m/yr within the aquifer
K	Confined aquifer	0.05 m/yr in the confining layer and 10 m/yr within the aquifer

[a]Several other variables, such as porosity, distinguish the flow fields, but the variables listed here are the most important for the purpose of this presentation.

[b]In general, an aquifer is defined as a geological unit that can transmit significant quantities of water. An unconfined aquifer is one that is only partly filled with water, such that the upper surface of the saturated zone is free to rise and decline. A confined aquifer is one that is completely filled with water and that is overlain by a confining layer (a rock unit that restricts the movement of ground water).

As a means of assessing potential effects on aquatic organisms, EPA estimated, for each model scenario involving surface water, the volume contaminated above an aquatic effects threshold. EPA also estimated the volumes of ground and surface water contaminated above various resource damage thresholds (e.g., the secondary drinking water standard for chloride).

QUANTITATIVE RISK MODELING RESULTS: HUMAN HEALTH

This section summarizes the health risk modeling results for onsite reserve pits (drilling wastes), underground injection wells (produced water), and direct discharges to surface water (produced water, stripper well scenarios only). Cancer risk estimates are presented separately from noncancer risk estimates throughout. This section also summarizes EPA's preliminary estimates of the size of populations that could possibly be exposed through drinking water.

Onsite Reserve Pits--Drilling Wastes

Cancer and noncancer health risks were analyzed under both best-estimate and conservative modeling assumptions for 1,134 model scenarios[8] of onsite reserve pits. Arsenic was the only potential carcinogen among the constituents modeled for onsite reserve pits. Of the noncarcinogens, only sodium exceeded its effect threshold; neither cadmium nor chromium VI exceeded their thresholds in any model scenarios (in its highest risk scenario, cadmium was at 15 percent of threshold; chromium VI, less than 1 percent).

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[8] 1,134 = 9 infiltration/unsaturated zone types x 7 ground-water flow field types x 3 exposure distances x 3 size categories x 2 liner types.

Nationally Weighted Risk Distributions

Figure V-3 presents the nationally weighted frequency distributions of human health risk estimates associated with unlined onsite reserve pits. The figure includes best-estimate and conservative modeling results for both cancer (top) and noncancer (bottom) risks. Only the results for unlined reserve pits are given because the presence or absence of a liner had little influence on risk levels (see section on major factors affecting health risk). Many of the scenarios in the figure show zero risk because the nearest potential exposure well was estimated to be more than 2 kilometers away (roughly 61 percent of all scenarios).

Under best-estimate assumptions, there were no cancer risks from arsenic because arsenic was not included as a constituent of the modeled waste (i.e., the median arsenic concentration in the field sampling data was below detection limits; see Table V-1). Under conservative assumptions, nonzero cancer risks resulting from arsenic were estimated for 18 percent of the nationally weighted reserve pit scenarios, with roughly 2 percent of the scenarios having cancer risks greater than 1×10^{-7}. Even under conservative modeling assumptions, drilling waste pit scenarios produced maximum lifetime cancer risks of less than 1 in 100,000 for individuals drinking affected water.

A few threshold exceedances for sodium were estimated under both best-estimate and conservative assumptions. Under best-estimate assumptions, more than 99 percent of nationally weighted reserve pit scenarios posed no noncancer risk (i.e., they were below threshold). A few model scenarios had noncancer risks, but none exceeded 10 times the sodium threshold. Under conservative assumptions, 98 percent of nationally weighted reserve pit scenarios did not pose a noncancer risk. The remaining 2 percent of reserve pit scenarios had estimated exposure point sodium concentrations between up to 32 times the threshold.

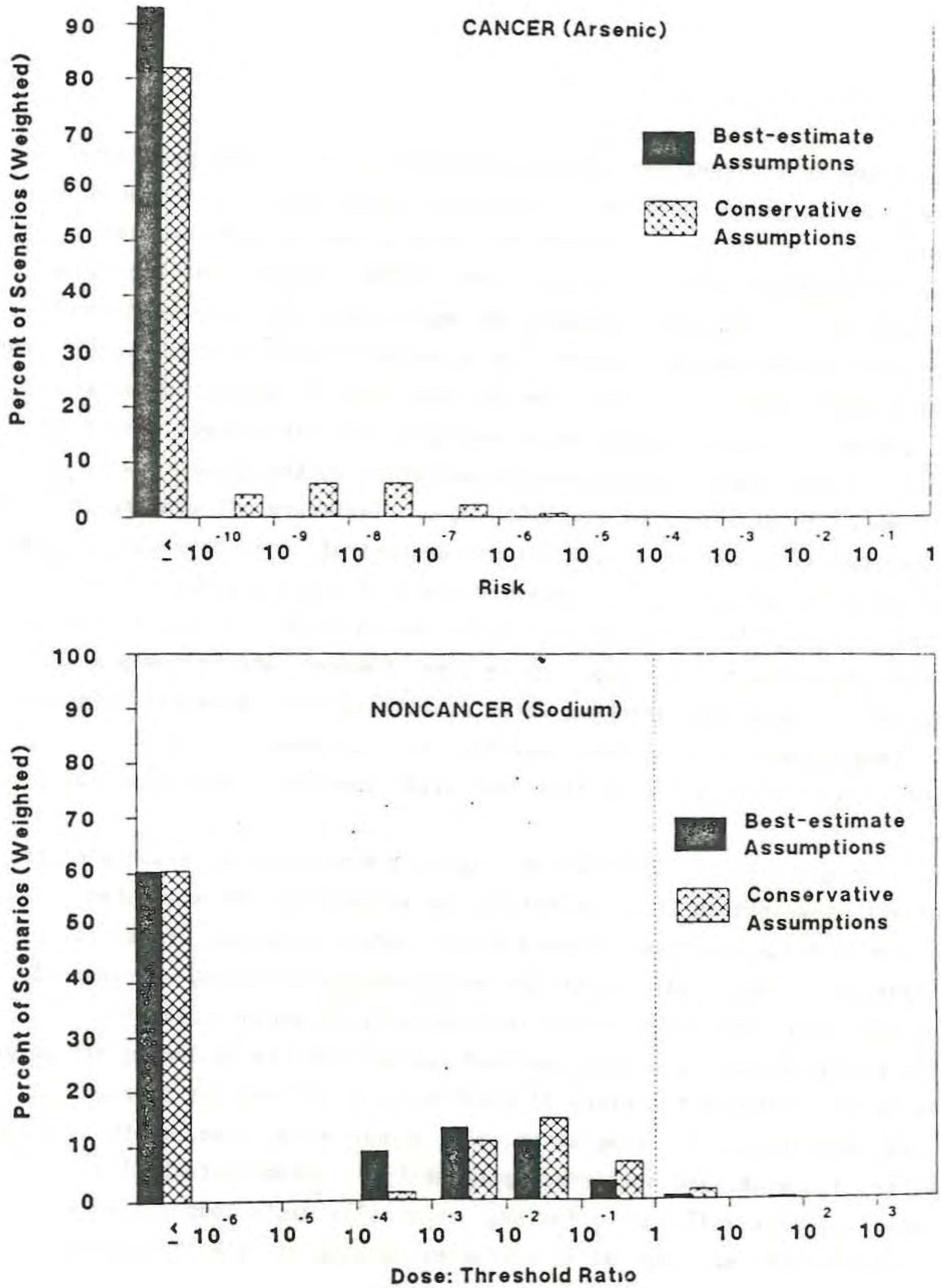

Figure V-3 Nationally Weighted Distribution of Health Risk Estimates. Unlined Reserve Pits

Based on a literature review conducted as part of the development of the Liner Location Model data base (USEPA 1986), chloride is the only model drilling waste constituent for which either a taste or odor threshold concentration is known. EPA (1984b) reports that the taste threshold for chloride is roughly 250 mg/L (i.e., this is the minimum chloride concentration in water that a person may be able to taste). For the highest cancer risk case, the maximum chloride concentration at the exposure well was estimated to be 400 mg/L; for the highest noncancer risk case, the maximum chloride concentration at the exposure well was estimated to be approximately 5,000 mg/L. Therefore, it appears that, if water contained a high enough arsenic concentration to pose cancer risks on the order of 1×10^{-5} or sodium concentrations 100 times the effect threshold, people may be able to taste the chloride that would also likely be present. The question remains, however, whether people would actually discontinue drinking water containing these elevated chloride concentrations. EPA (1984b) cautions that consumers may become accustomed to the taste of chloride levels somewhat higher than 250 mg/L.

For purposes of illustration, Figure V-4 provides an example of the effect of weighting the risk results to account for the estimated national frequency of occurrence of the model scenarios. Essentially, weighting allows risk results for more commonly occurring scenarios to "count" more than results from less commonly occurring scenarios. Weighting factors were developed and applied for the following variables, based on estimated frequency of occurrence at oil and gas sites: pit size, distance to drinking water well, ground-water type, depth to ground water, recharge, and subsurface permeability. Other potentially important risk-influencing factors, especially waste composition and strength, were not modeled as variables because of lack of information and thus are not accounted for by weighting.

In the example shown in Figure V-4 (conservative-estimate cancer risks for unlined onsite pits), weighting the risk results decreases the

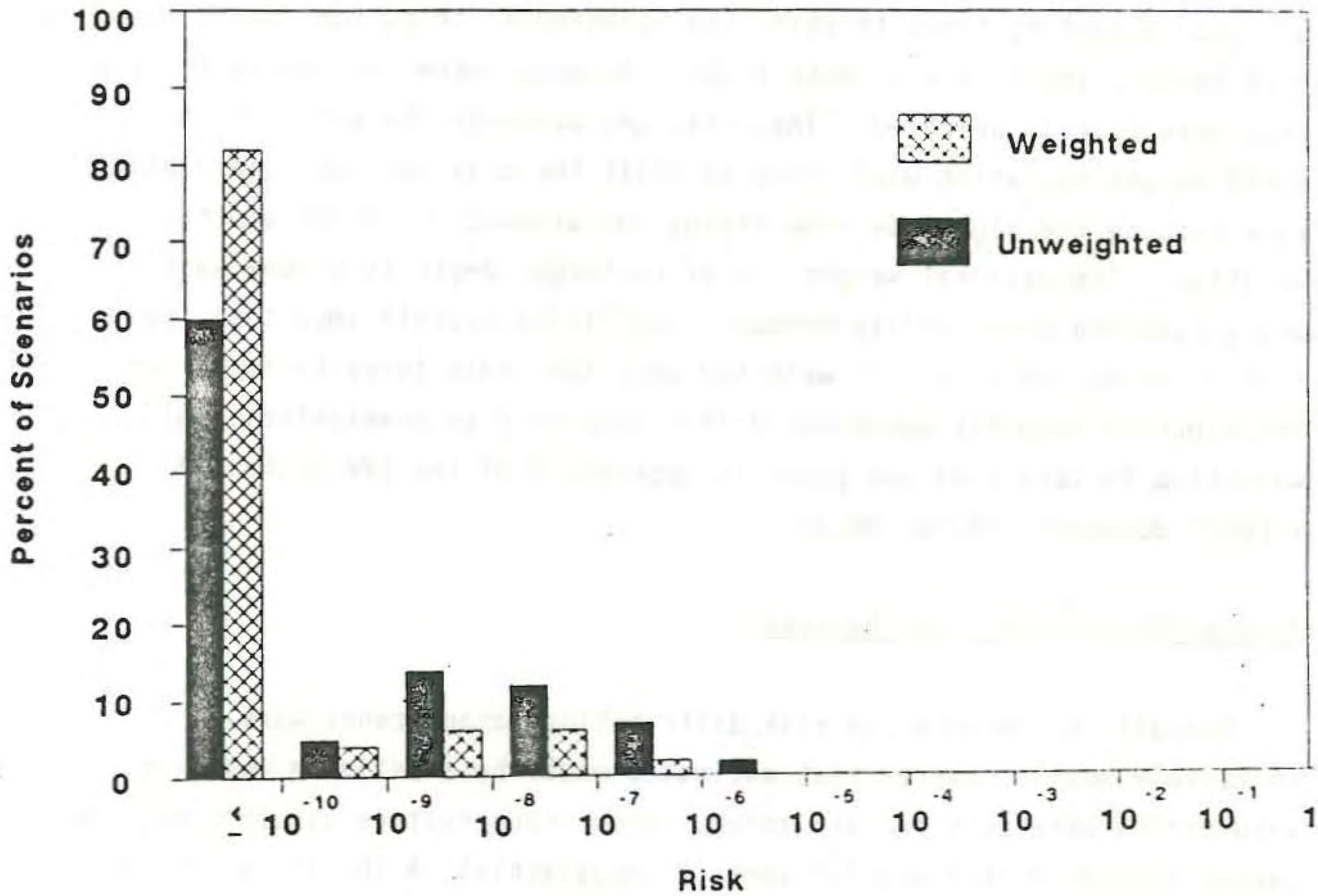

Figure V-4 Weighted vs. Unweighted Distribution of Cancer Risk Estimates. Unlined Reserve Pits. Conservative Modeling Assumptions risk (i.e., shifts the distribution toward lower risk). This happens primarily because close exposure distances (60 and 200 meters), which correspond to relatively high risks, occur less frequently and thus are less heavily weighted than greater distances. In addition, the effect of pit size weighting tends to shift the weighted distribution toward lower risk because small (i.e., lower risk) pits occur more frequently and are thus more heavily weighted. These factors override the effect of flow field weighting, which would tend to shift the distribution toward higher risk because the high-risk flow fields for arsenic (C and D) are heavily weighted. The national weightings of recharge, depth to ground water, and subsurface permeability probably had little overall impact on the risk distribution (i.e., if weighted only for these three factors, the distribution probably would not differ greatly from unweighted). All weighting factors used are given in Appendix B of the EPA technical support document (USEPA 1987a).

Zone-Weighted Risk Distributions

Overall, differences in risk distributions among zones were relatively small. Cancer risk estimates under best-estimate modeling assumptions were zero for all zones. Under conservative assumptions, the cancer risk distributions for zones 2 (Appalachia), 4 (Gulf), 6 (Plains), and 7 (Texas/Oklahoma) were slightly higher than the distribution for the nation as a whole. The cancer risk distributions for zones 5 (Midwest), 8 (Northern Mountain), 9 (Southern Mountain), 10 (West Coast), and 11B (Alaska, non-North Slope) were lower than the nationally weighted distribution; zones 10 and 11B were much lower. The risk distributions for individual zones generally varied from the national distribution by less than one order of magnitude.

Noncancer risk estimates under best-estimate modeling assumptions were extremely low for all zones. Under conservative assumptions, zones 2, 4, 5, 7, and 8 had a small percentage (1 to 10 percent) of weighted scenarios with threshold exceedances for sodium; other zones had less than 1 percent. There was little variability in the noncancer risk distributions across zones.

The reasons behind the differences in risks across zones are related to the zone-specific relative weightings of reserve pit size, distance to receptor populations, and/or environmental variables. For example, the main reason zone 10 has low risks relative to other zones is that 92 percent of drilling sites were estimated to be in an arid setting above a relatively low-risk ground-water flow field having an aquitard (flow field F). Zone 11B has zero risks because all potential exposure wells were estimated to be more than 2 kilometers away.

In summary, differences in cancer risks among the geographic zones were not great. Cancer risks were only prevalent in the faster aquifers (i.e., flow fields C, D, and E, with C having the highest cancer risks). Zone 4, with the highest cancer risks overall, also was assigned the highest weighting among the zones for flow field C. Noncancer risks caused by sodium were highest in zone 5. Noncancer risks occurred only in the more slow-moving flow fields (i.e., flow fields A, B, and K, with A having the highest noncancer risks); among the zones, zone 5 was assigned the highest weighting for flow field A. EPA considered the possible role of distributions of size and distance to exposure points, but determined that aquifer configuration and velocity probably contributed most strongly to observed zone differences in estimates of human health risks. The consistent lack of risk for zone 11B, however, is entirely because of the large distance to an exposure point. (See the section that follows on estimated population distributions.)

Evaluation of Major Factors Affecting Health Risk

EPA examined the effect of several parameters related to pit design and environmental setting that were expected to influence the release and transport of contaminants leaking from onsite reserve pits. To assess the effect of each of these parameters in isolation, all other parameters were held constant for the comparisons. The results presented in this section are not weighted according to either national or zone-specific frequencies of occurrence. Instead, each model scenario is given equal weight. Thus, the following comparisons are not appropriate for drawing conclusions concerning levels of risk for the national population of onsite reserve pits. They are appropriate for examining the effect of selected parameters on estimates of human health risk.

The presence or absence of a conventional, single synthetic liner underneath an onsite reserve pit had virtually no effect on the 200-year maximum health risk estimates. A liner does affect timing of exposures and risks, however, by reducing the amounts of leachate (and chemicals) released early in the modeling period. EPA's modeling assumed a single synthetic liner with no leak detection or leachate collection. (Note that this is significantly different from the required Subtitle C liner system design for hazardous waste land disposal units.) Furthermore, EPA assumed that such a liner would eventually degrade and fail, resulting in release of the contaminants that had been contained. Thus, over a long modeling period, mobile contaminants that do not degrade or degrade very slowly (such as the ones modeled here) will produce similar maximum risks whether they are disposed of in single-synthetic-lined or unlined pits (unless a significant amount of the contained chemical is removed, such as by dredging). This finding should not be interpreted to discount the benefit of liners in general. Measures of risk over time periods shorter than 200 years would likely be lower for lined pits than for unlined ones. Moreover, by delaying any release of contaminants, liners provide the opportunity for management actions (e.g., removal) to help prevent contaminant seepage and to mitigate seepage should it occur.

Figure V-5 represents unweighted risks associated with unlined reserve pits under the conservative modeling assumptions for three reserve pit sizes and three distances to the exposure point. Each combination of distance and reserve pit size includes the risk results from all environmental settings modeled (total of 63), equally weighted. Figure V-5 shows that the unweighted risk levels decline with increasing distance to the downgradient drinking water well. The decline is generally less than an order of magnitude from 60 to 200 meters, and greater than an order of magnitude from 200 to 1,500 meters. Median cancer risk values exceed 10^{-10} only at the 60-meter distance, and median dose-to-threshold ratios for noncancer effects exceed 1.0 only for large pits at the 60-meter distance. Risks also decrease as reserve pit size decreases at all three distances, although risks for small and large pits are usually within the same order of magnitude.

Figure V-6 compares risks across the seven ground-water flow field types modeled in this analysis. Both cancer and noncancer risks vary substantially across flow fields. The noncancer risks (from sodium) are greatest in the slower moving flow fields that provide less dilution (i.e., flow fields A, B, and K), while the cancer risks (from arsenic) are greatest in the higher velocity/higher flow settings (i.e., flow fields C, D, and E). Sodium is highly mobile in ground water, and it is diluted to below threshold levels more readily in the high-velocity/high-flow aquifers. Arsenic is only moderately mobile in ground water and tends not to reach downgradient exposure points within the 200-year modeling period in the slower flow fields. If the modeling period were extended, cancer risks resulting from arsenic would appear in the more slowly moving flow field scenarios.

As would be expected, both cancer and noncancer risks increased with increasing recharge rate and with increasing subsurface permeability. Risk differences were generally less than an order of magnitude. Depth to ground water had very little effect on the 200-year maximum risk,

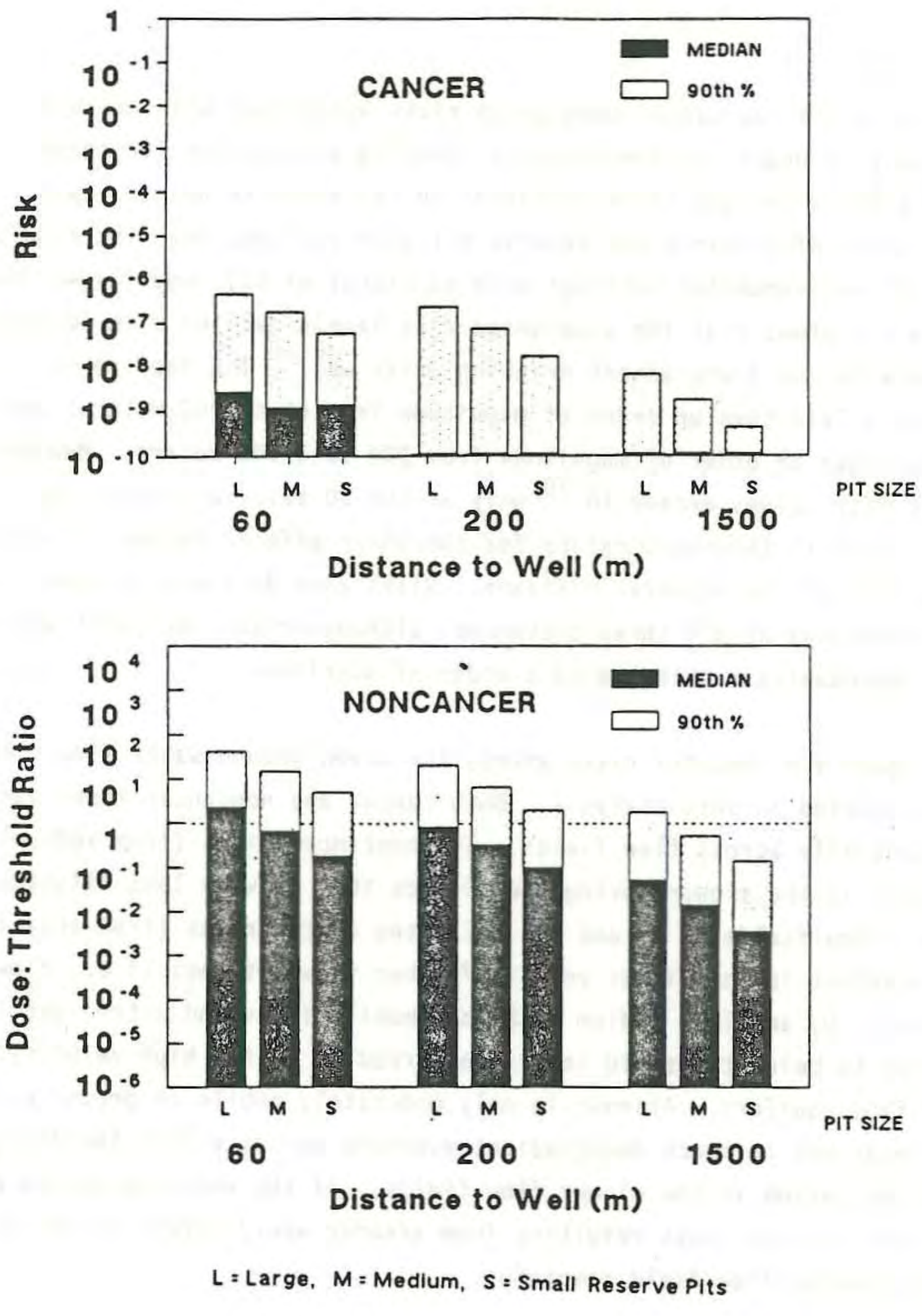

Figure V-5 Health Risk Estimates (Unweighted) as a Function of Size and Distance. Unlined Reserve Pits. Conservative Modeling Assumptions

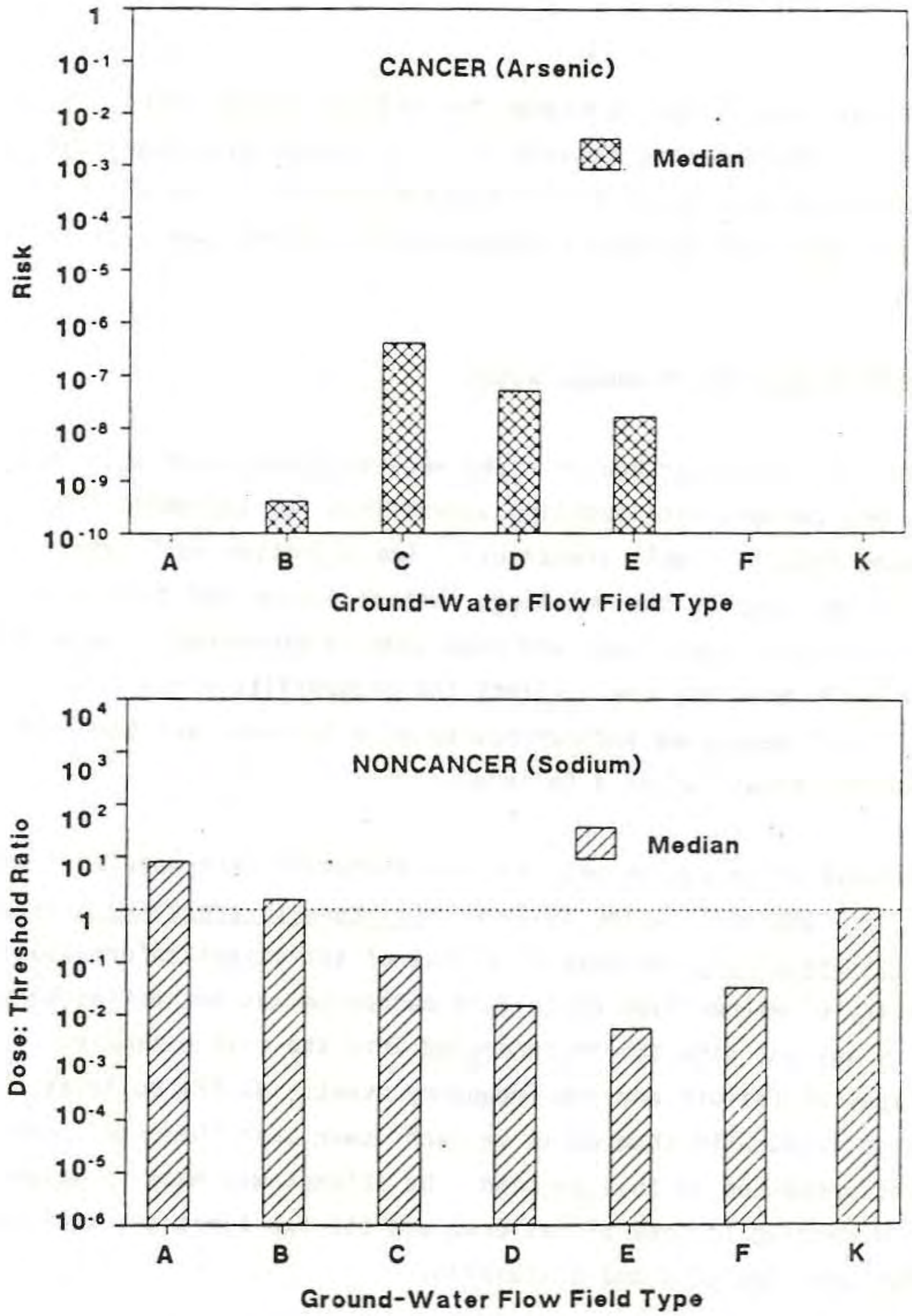

Figure V-6 Health Risk Estimates (Unweighted) as a Function of Ground-Water Type. Unlined Reserve Pits (Large). 60-Meter Exposure Distance. Conservative Modeling Assumptions although risks were slightly higher for shallow ground-water settings. This lack of effect occurs because the risk-producing contaminants are at least moderately mobile and do not degrade rapidly, if at all; thus, the main effect observed for deeper ground-water settings was a delay in exposures.

Underground Injection--Produced Water

Cancer and noncancer health risks were analyzed under both best-estimate and conservative modeling assumptions for 168 model Class II underground injection well scenarios.[9] Two injection well types were differentiated in the modeling: waterflooding and dedicated disposal. Design, operating, and regulatory differences between the two types of wells possibly could affect the probability of failure, the probability of detection and correction of a failure, and the likely magnitude of release given a failure.

Two types of injection well failure mechanism were modeled: grout seal failure and well casing failure. All results presented here assume that a failure occurs; because of a lack of sufficient information, the probability of either type of failure mechanism was not estimated and therefore was not directly incorporated into the risk estimates. If these types of failure are low-frequency events, as EPA believes, actual risks associated with them would be much lower than the conditional risk estimates presented in this section. No attempt was made to weight risk results according to type of failure, and the two types are kept separate throughout the analysis and discussion.

Nationally Weighted Risk Distributions

The risk estimates associated with injection well failures were weighted based on the estimated frequency of occurrence of the following

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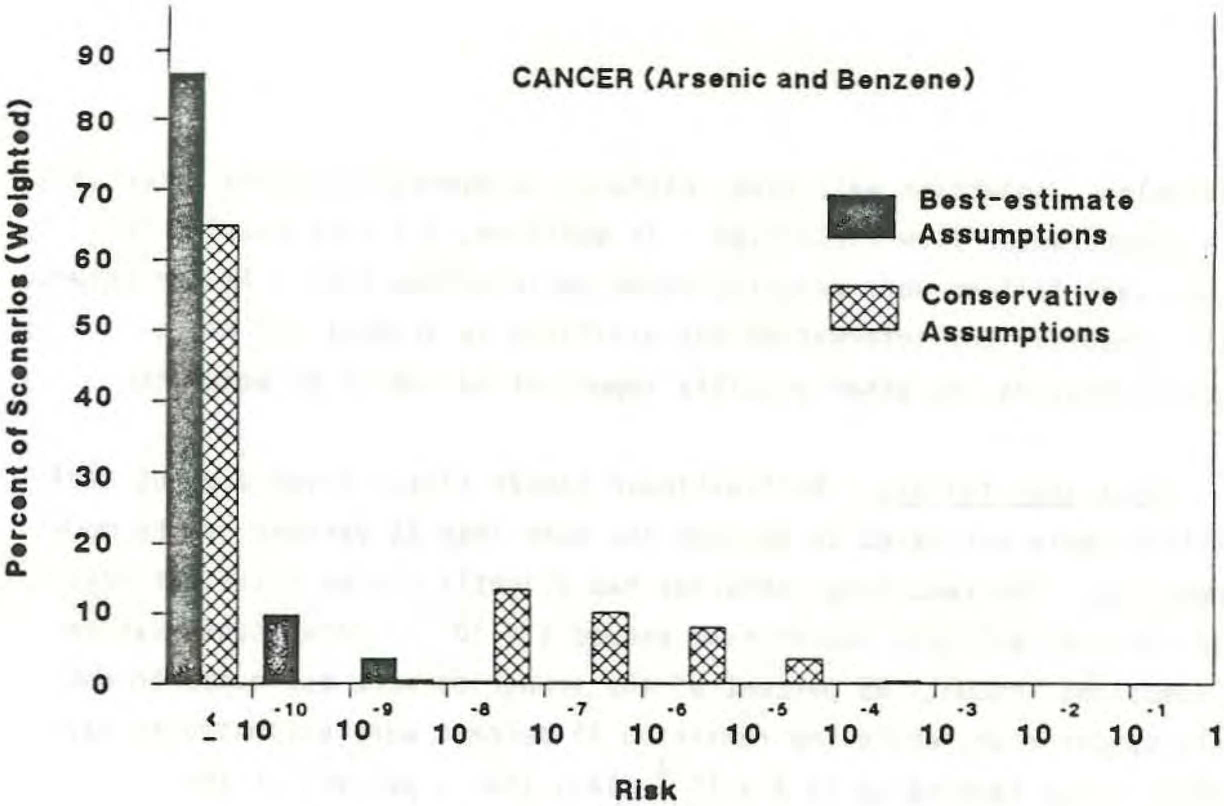
9 168 = 7 ground-water flow field types x 3 exposure distances x 2 size categories x 2 well types x 2 failure mechanisms.

variables: injection well type, distance to nearest drinking water well, and ground-water flow field type. In addition, all risk results for grout seal failure were weighted based on injection rate. As for reserve pits, insufficient information was available to account for waste characteristics and other possibly important variables by weighting.

Grout seal failure: Best-estimate cancer risks, given a grout seal failure, were estimated to be zero for more than 85 percent of the model scenarios. The remaining scenarios had slightly higher risks but never did the best-estimate cancer risk exceed 1×10^{-7}. Under conservative assumptions, roughly 65 percent of the scenarios were estimated to have zero cancer risk, while the remaining 35 percent were estimated to have cancer risks ranging up to 4×10^{-4} (less than 1 percent of the scenarios had greater than 1×10^{4} risk). These modeled cancer risks were attributable to exposure to two produced water constituents, benzene and arsenic. Figure V-7 (top portion) provides a nationally weighted frequency distribution of the best-estimate and conservative-estimate cancer risks, given a grout seal failure. Figure V-7 shows the combined distribution for the two well types and two injection rates considered in the analysis, the three exposure distances, and the seven ground-water settings. As with drilling pits, many of the zero risk cases were because the nearest potential exposure well was estimated to be more than 2 kilometers away (roughly 64 percent of all scenarios).

Modeled noncancer risks, given a grout seal failure, are entirely attributable to exposures to sodium. There were no sodium threshold exceedances associated with grout seal failures under best-estimate conditions. Under conservative conditions, roughly 95 percent of the nationally weighted model scenarios also had no noncancer risk. The remaining 5 percent had estimated sodium concentrations at the exposure point that exceeded the effect threshold, with the maximum concentration exceeding the effect threshold by a factor of 70. The nationally



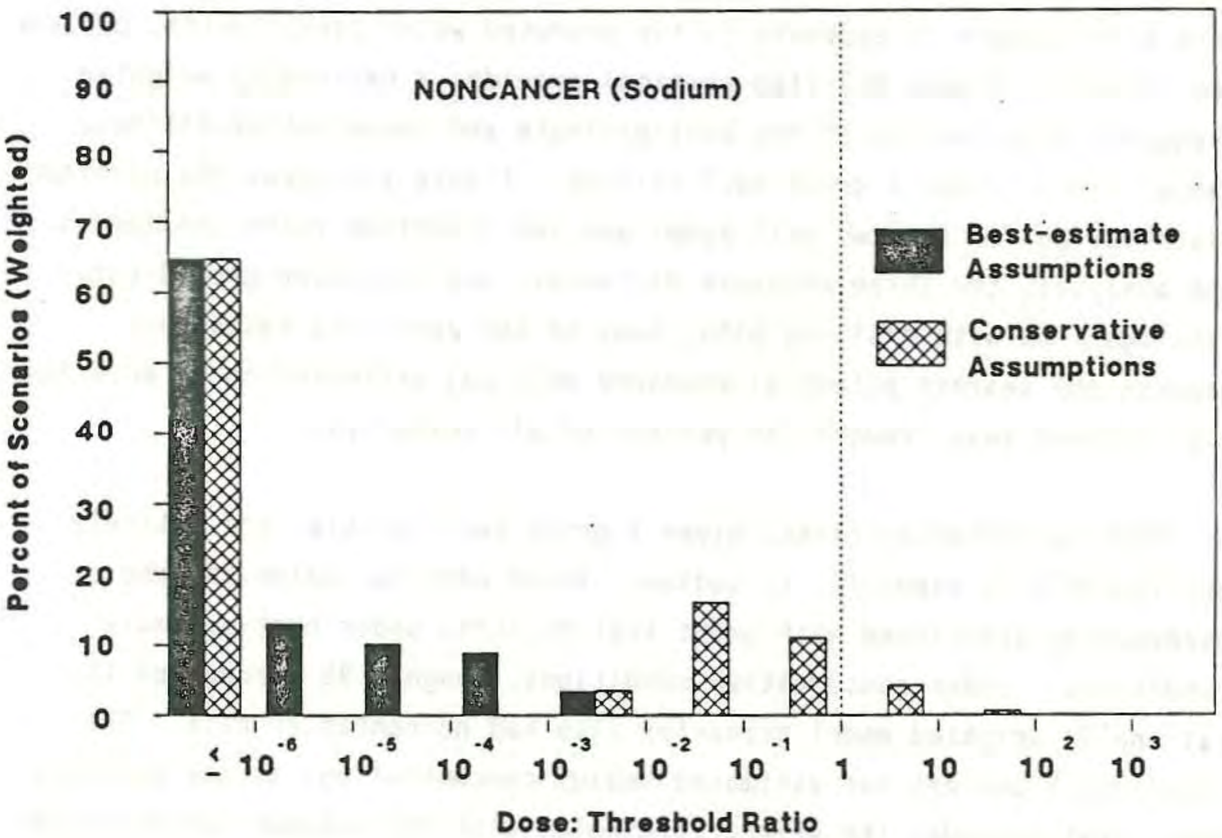


Figure V-7 Nationally Weighted Distribution of Health Risk Estimates. Underground Injection Wells: Grout Seal Failure Assumed weighted frequency distribution of the estimated dose/threshold ratios for sodium is shown in the bottom portion of Figure V-7.

Data are available on the taste and odor thresholds of two produced water model constituents: benzene and chloride. For the maximum cancer risk scenario assuming a grout seal failure, the estimated concentrations of benzene and chloride at the exposure well were below their respective taste and odor thresholds. However, for the maximum noncancer risk scenario assuming a grout seal failure, the estimated chloride concentration did exceed the taste threshold by roughly a factor of three. Therefore, people might be able to taste chloride in the highest noncancer risk scenarios, but it is questionable whether anybody would discontinue drinking water containing such a chloride concentration.

Well casing failure: The nationally weighted distributions of estimated cancer and noncancer risks, given an injection well casing failure, are presented in Figures V-8 and V-9. Figure V-8 gives the risk distributions for scenarios with high injection pressure, and Figure V-9 gives the risk distributions for scenarios with low injection pressure. (Because of a lack of adequate data to estimate the distribution of injection pressures, results for the high and low pressure categories were not weighted and therefore had to be kept separate.)

Best-estimate cancer risks, given a casing failure, were zero for approximately 65 percent of both the high and low pressure scenarios; the remaining scenarios had cancer risk estimates ranging up to 5×10^{-6} for high pressure and 1×10^{-6} for low pressure. The majority (65 percent) of both high and low pressure scenarios also had no cancer risks under the conservative assumptions, although approximately 5 percent of the high pressure scenarios and 1 percent of the low pressure scenarios had conservative-estimate cancer risks greater than 1×10^{-4} (maximum of 9×10^{4}). The rest of the scenarios had conservative-estimate cancer risks greater than zero and less than 1×10^{-4}.

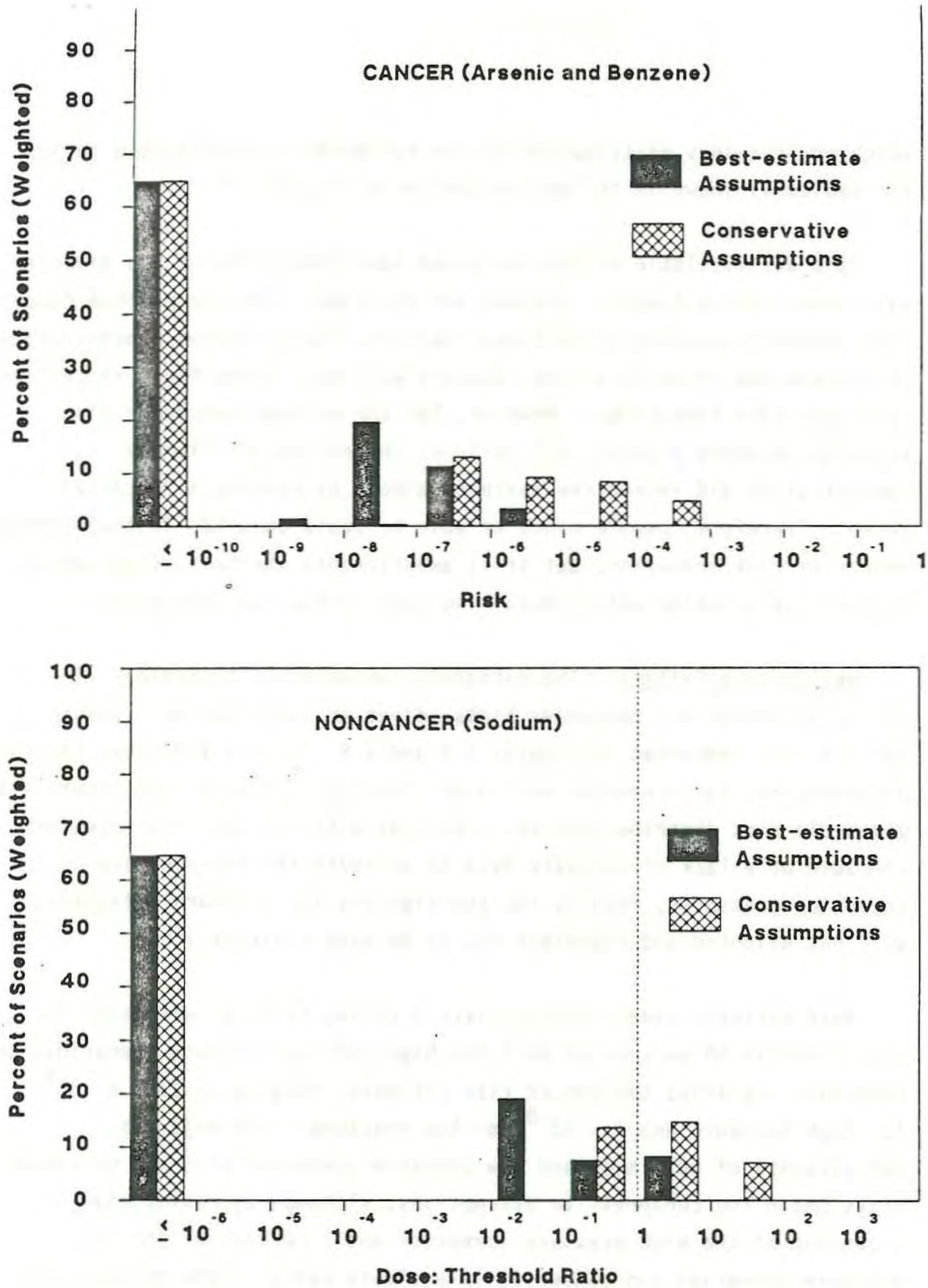


Figure V-8 Nationally Weighted Distribution of Health Risk Estimates. High Pressure Underground Injection Wells: Casing Failure Assumed

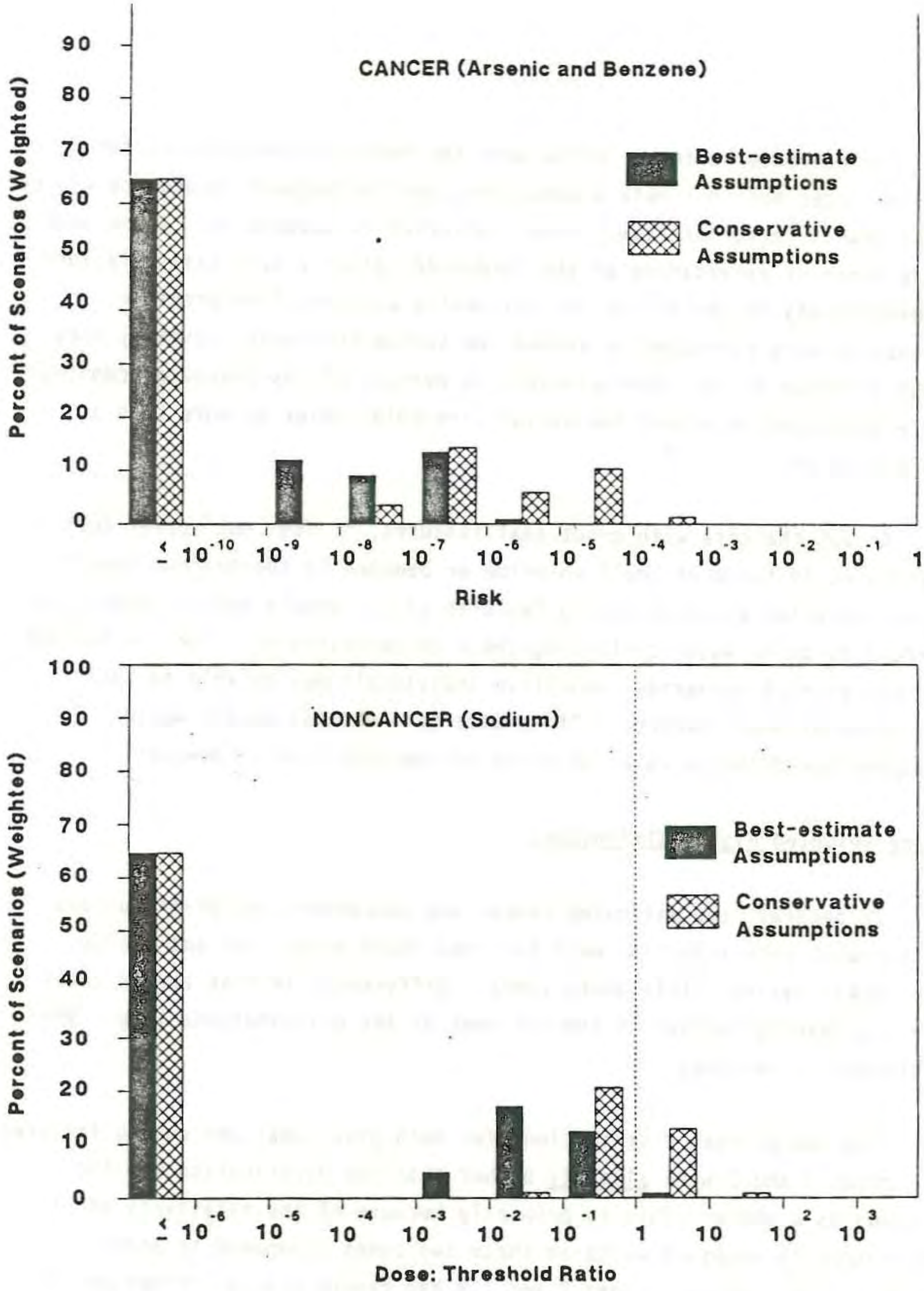


Figure V-9 Nationally Weighted Distribution of Health Risk Estimates. Low Pressure Underground Injection Wells: Casing Failure Assumed

For noncancer effects, there were few threshold exceedances for sodium under best-estimate assumptions, and the highest exceedance was by less than a factor of five. Under conservative assumptions, there were more numerous exceedances of the threshold, given a well casing failure. Approximately 22 percent of the nationally weighted high pressure scenarios were estimated to exceed the sodium threshold, never by more than a factor of 70. Approximately 14 percent of low pressure scenarios were estimated to exceed the sodium threshold, never by more than a factor of 35.

As was the case with grout seal failures, it does not appear that people would taste or smell chloride or benzene in the maximum cancer risk scenarios assuming casing failures (i.e., people would probably not refuse to drink water containing these concentrations). For the maximum noncancer risk scenarios, sensitive individuals may be able to taste chloride or smell benzene. It is uncertain whether people would discontinue drinking water at these contaminant levels, however.

<u>Zone-Weighted Risk Distributions</u>

In general, the estimated cancer and noncancer risk distributions associated with injection well failures (both grout seal and casing failures) varied little among zones. Differences in risk across zones were primarily limited to the extremes of the distributions (e.g., 90th percentile, maximum).

The cancer risk distributions for both grout seal and casing failures in zones 2 and 5 were <u>slightly</u> higher than the distribution for the nation as a whole. This is primarily because of the relatively short distances to exposure wells in these two zones (compared to other zones). In contrast, zones 8 and 11B had cancer risk distributions for injection well failures that were <u>slightly</u> lower than the national distribution. This difference is primarily because of the relatively long distance to exposure wells in these zones. (For almost 80 percent of production sites in both zones, it was estimated that the closest exposure well was more than 2 kilometers away.) A similar pattern of zone differences was observed for the noncancer risk results.

Evaluation of Major Factors Affecting Health Risk

In general, estimated risks associated with well casing failure are from one to two orders of magnitude higher than risks associated with grout seal failure. This is because under most conditions modeled, well casing failures are estimated to release a greater waste volume, and thus a larger mass of contaminants, than grout seal failures.

The risks estimated for disposal and waterflood wells are generally similar in magnitude. For assumed casing failures, waterflood wells are estimated to cause slightly (no more than a factor of 2.5 times) higher risks than disposal wells. This pattern is the net result of two differences in the way waterflood and disposal wells were modeled. The release durations modeled for disposal wells are longer than those for waterflood wells, but the injection pressures modeled for waterflood wells are greater than those modeled for disposal wells. For assumed grout seal failures, disposal wells are estimated to cause slightly (no more than a factor of 3 times) higher risks than waterflood wells. This pattern results because the injection rates modeled for disposal wells are up to 3 times greater than those modeled for waterflood wells.

The distance to a potentially affected exposure well at an injection site is one of the most important indicators of risk potential. If all other parameters remain constant, carcinogenic risks decline slightly less than one order of magnitude between the 60-meter and 200-meter well distances; carcinogenic risks decline between one and two orders of magnitude from the 200-meter to the 1,500-meter well distances. The effect of well distance is a little less pronounced for noncarcinogenic risks. Sodium threshold exceedances drop by less than an order of magnitude between the 60-meter and 200-meter well distances and by approximately one order of magnitude between the 200-meter and 1,500-meter well distances. The reduction in exposure with increased distance from the well is attributable to three-dimensional dispersion of contaminants within the saturated zone. In addition, the 200-year modeling period limits risks resulting from less mobile constituents at greater distances (especially 1,500 meters). Degradation is not a factor because the constituents producing risk degrade very slowly (if at all) in the saturated zone.

Cancer and noncancer risk estimates decrease with decreasing injection rate/pressure. This relationship reflects the dependence of risk upon the total chemical mass released into the aquifer each year, which is proportional to either the assumed injection flow rate (grout seal failure) or pressure (casing failure).

Figure V-10 shows how the unweighted health risk estimates associated with injection well casing failures varied for the different ground-water flow fields. The figure includes only results for the conservative modeling assumptions, the high injection pressure, and the 60-meter modeling distance, because risk estimates under best-estimate assumptions and for other modeling conditions were substantially reduced and less varied. As shown, conservative-estimate carcinogenic risks ranged from roughly 2×10^{-6} (for flow field F) to approximately 6×10^{-4} (for flow field D). The difference in the risk estimates for these two flow fields is due primarily to their different aquifer configurations. Flow field D represents an unconfined aquifer, which is more susceptible to contamination than a confined aquifer setting represented by flow field F.

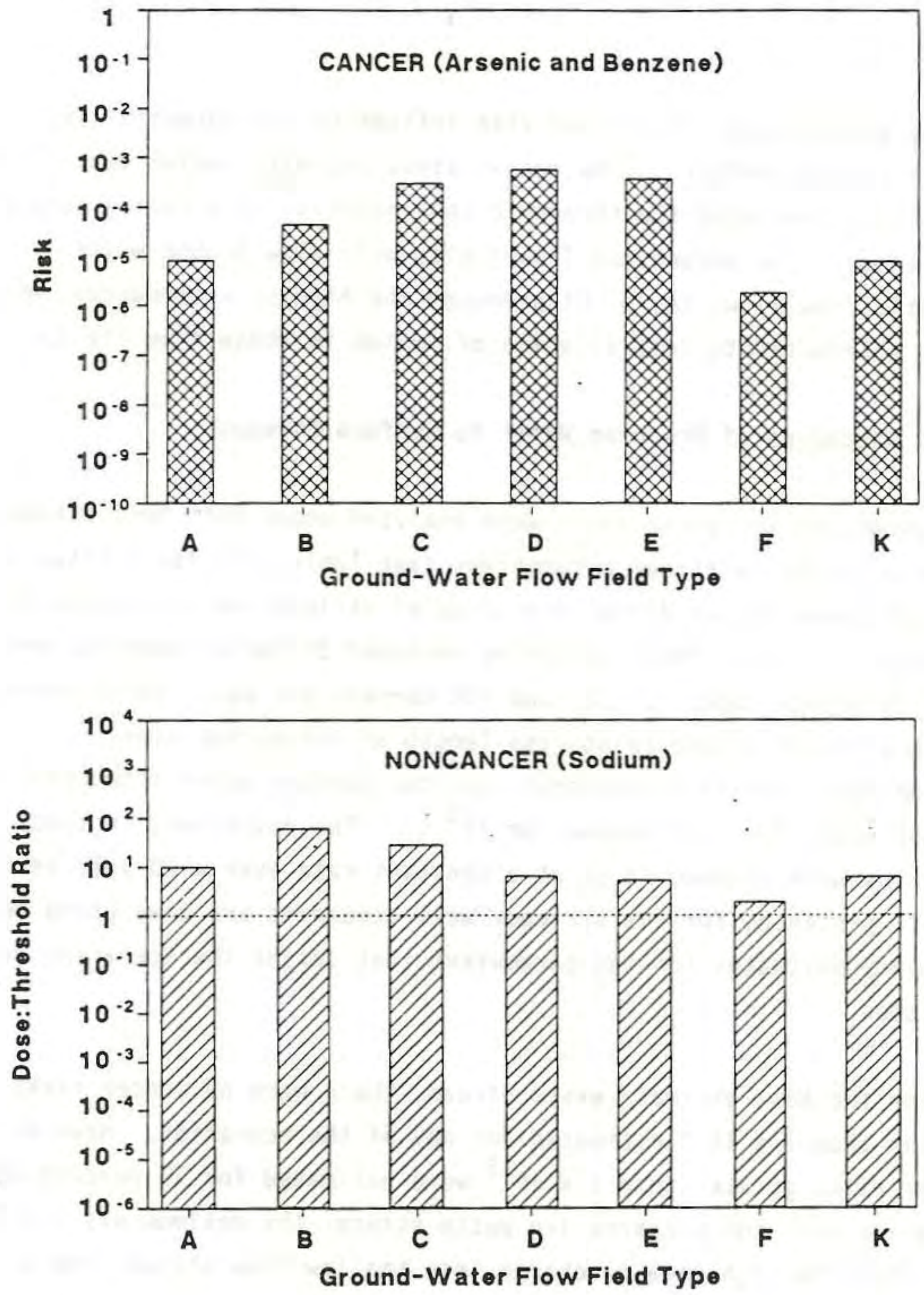


Figure V-10 Health Risk Estimates (Unweighted) as a Function of Ground-Water Type. High Pressure Underground Injection Wells: Casing Failure Assumed. 60-Meter Exposure Distance. Conservative Modeling Assumptions

The ground-water flow field also influenced the potential for noncarcinogenic effects. The conservative-estimate sodium concentrations at 60 meters exceeded the threshold concentration by a factor ranging up to 70 times. The unconfined flow fields with slow ground-water velocities/low flows (A, B, C) produced the highest exceedances, which can be attributed to less dilution of sodium in these flow fields.

Direct Discharge of Produced Water to Surface Streams

Cancer and noncancer risks were analyzed under both best-estimate and conservative waste stream assumptions (see Table V-1) for a total of 18 model scenarios of direct discharge of stripper well-produced fluids to surface waters. These scenarios included different combinations of three discharge rates (1, 10, and 100 barrels per day), three downstream distances to an intake point (the length of the mixing zone, 5 kilometers, and 50 kilometers), and two surface water flow rates (40 and 850 cubic feet per second, or ft^3/s). The discharges in these scenarios were assumed to be at a constant rate over a 20-year period. Results presented for the stripper well scenarios are unweighted because frequency estimates for the parameters that define the scenarios were not developed.

For the best-estimate waste stream, there were no cancer risks greater than 1×10^{-5} estimated for any of the scenarios. However, cancer risks greater than 1×10^{-5} were estimated for 17 percent of the scenarios with the conservative waste stream--the maximum was 3.5×10^{-5} (for the high-rate discharge into the low-flow stream, and a drinking water intake immediately downstream of the discharge point). These cancer risks were due primarily to exposure to arsenic, although benzene also contributed slightly. For noncancer risks, none of the scenarios had a threshold exceedance for sodium, regardless of whether the best-estimate or conservative waste stream was assumed.

EPA recognizes that the model surface water flow rates (40 and 850 ft^3/s) are relatively high and that discharges into streams or rivers with flow rates less than 40 ft^3/s could result in greater risks than are presented here. Therefore, to supplement the risk results for the model scenarios, EPA analyzed what a river or stream flow rate would have to be (given the model waste stream concentrations and discharges rates) in order for the contaminant concentration in the mixing zone (assuming instantaneous and complete mixing but no other removal processes) to be at certain levels.

The results of this analysis, presented in Table V-8, demonstrate that reference concentrations of benzene would be exceeded only in very low-flow streams (i.e., less than 5 ft^3/s) under all of the model conditions analyzed. It is unlikely that streams of this size would be used as drinking water sources for long periods of time. However, concentrations of arsenic and sodium under conservative modeling conditions could exceed reference levels in the mixing zone in relatively large streams, which might be used as drinking water sources. The concentrations would be reduced at downstream distances, although estimates of the surface water flow rates corresponding to reference concentrations at different distances have not been made.

Potentially Exposed Population

Preliminary estimates of the potentially exposed population were developed by estimating the number of individuals using private drinking water wells and public water supplies located downgradient from a sample of oil and gas wells. These estimates were based on data obtained from local water suppliers and 300 USGS topographic maps. One hundred of the maps were selected from areas containing high levels of drilling activity, and 200 were selected from areas containing high levels of production.

Table V-8 Surface Water Flow Rates At Which Concentrations of Waste Stream Constituents in the Mixing Zone Will Exceed Reference Levels[a]

Constituent	Concentration in waste	Waste stream discharge rate High (100 BPD)	Medium (10 BPD)	Low (1 BPD)
Arsenic	Median	$\leq$ 5 ft^3/s [b]	$\leq$0.5 ft^3/s	$\leq$ .05 ft^3/s
	90th %	$\leq$ 470 ft^3/s	$\leq$ 50 ft^3/s	$\leq$ 5 ft^3/s
Benzene	Median	$\leq$ 1 ft^3/s	$\leq$ 0.1 ft^3/s	$\leq$ 0.01 ft^3/s
	90th %	$\leq$ 3 ft^3/s	$\leq$ 0.3 ft^3/s	$\leq$ 0.03 ft^3/s
Sodium	Median	$\leq$ 3 ft^3/s	$\leq$ 0.3 ft^3/s	$\leq$ 0.03 ft^3/s
	90th %	$\leq$ 20 ft^3/s	$\leq$ 2 ft^3/s	$\leq$ 0.2 ft^3/s

[a]The reference levels referred to are the arsenic and benzene concentrations that correspond to a 1×10^{-5} lifetime cancer risk level (assuming a 70-kg individual ingests 2 L/d) and EPA's suggested guidance level for sodium for the prevention of hypertension in high-risk individuals.

[b]Should be interpreted to mean that the concentration of arsenic in the mixing zone would exceed the 1×10^{-5} lifetime cancer risk level if the receiving stream or river was flowing at a rate of 5 ft^3/s or lower. If the stream or river was flowing at a higher rate, then the maximum concentration of arsenic would not exceed the 1×10^{-5} lifetime cancer risk level.

Table V-9 summarizes the sample results for the population potentially exposed through private drinking water wells. As shown in this table, over 60 percent of the oil and gas wells in both the drilling and production sample did not have private drinking water wells within 2,000 meters downgradient and only 2 percent of the oil and gas wells were estimated to have private drinking water wells within the 60-meter (i.e., higher-risk) distance category. Moreover, the numbers of potentially affected people per oil and gas well in the 60-meter distance category were relatively small. One other interesting finding demonstrated in Table V-9 is that fewer potentially affected individuals were estimated to be in the 1,500-meter distance category than in the 200-meter category. This situation is believed to occur because some residences located farther from oil and gas wells were on the other side of surface waters that appeared to be a point of ground-water discharge.

The sample results for the population potentially exposed through public water supplies are summarized in Table V-10. These results show a pattern similar to those for private drinking water wells; this is, most oil and gas wells do not have public water supply intakes within 2,000 meters and of those that do only a small fraction have public water supply intakes within the 60-meter distance category.

The results in Tables V-9 and V-10 are for the nation as a whole. Recognizing the limitations of the sample and of the analysis methods, EPA's data suggest that zone 2 (Appalachia) and zone 7 (Texas/Oklahoma) have the greatest relative number of potentially affected individuals per oil and gas well (i.e., potentially affected individuals are, on the average, closer to oil and gas wells in these zones relative to other zones). In addition, zone 4 (Gulf) has a relatively large number of individuals potentially affected through public water supplies. Zone 11 (Alaska) and zone 8 (Northern Mountain) appear to have relatively fewer potentially affected individuals per oil and gas well. Further

Table V-9 Population Potentially Exposed Through Private Drinking Water Wells at Sample Drilling and Production Areas

	Drilling sample results		Production sample results	
Distance category[a]	No. (%) of oil/gas wells with private drinking water wells within distance category	Maximum no. of potentially affected individuals per oil and gas well[b]	No. (%) of oil/gas wells with private drinking water wells within distance category	Maximum no. of potentially affected individuals per oil and gas well[b]
60 meters	561(2)	0.11	642(2)	0.17
200 meters	4,765(17)	0.44	5,139(16)	0.58
1,500 meters	5,606(20)	0.32	5,460(17)	0.36
>2,000 meters	17,096(61)	NA[c]	20,879(65)	NA

[a]Drinking water wells were counted as 60 meters downgradient if they were within 0 and 130 meters, were counted as 200 meters downgradient if they were within 130 and 800 meters, and were counted as 1,500 meters downgradient if they were within 800 and 2,000 meters.

[b]These ratios largely overestimate the number of people actually affected per oil and gas well (see text) and should be used to estimate the total number of people affected only with caution. The figures are intended simply to give a preliminary indication of the potentially exposed population and the distribution of that population in different distance categories.

[c]Not available; distances greater than 2,000 meters from oil and gas wells were not modeled.

Table V-10 Population Potentially Exposed Through Public Water Supplies at Sample Drilling and Production Areas

	Drilling sample results			Production sample results		
Distance category[a]	No. (%) of oil/gas wells with private drinking water wells within distance category		Maximum no. of potentially affected individuals per oil and gas well[b]	No. (%) of oil/gas wells with private drinking water wells within distance category		Maximum no. of potentially affected individuals per oil and gas well[b]
60 meters	87	(0.3)	3.6	54	(0.2)	96
200 meters	217	(0.8)	0.76	210	(0.7)	8.1
1,500 meters	232	(0.8)	0.55	617	(2)	3.9
>2,000 meters	27,492	(98)	NA[c]	31,239	(97)	NA[c]

[a]Public water supply intakes were counted as 60 meters downgradient if they were within 0 and 130 meters, were counted as 200 meters downgradient if they were within 130 and 800 meters, and were counted as 1,500 meters downgradient if they were within 800 and 2,000 meters.

[b]These ratios largely overestimate the number of people actually affected per oil and gas well (see text) and should be used to estimate the total number of people affected only with caution. The figures are intended simply to give a preliminary indication of the potentially exposed population and the distribution of that population in different distance categories.

[c]Not available; distances greater than 2,000 meters from oil and gas wells were not modeled.

discussion of the differences in population estimates across zones is provided in the supporting technical report (USEPA 1987a).

The number of potentially affected people per oil and gas well in Tables V-9 and V-10 represents the maximum number of people in the sample that could be affected if all the oil and gas wells in the sample resulted in ground-water contamination out to 2,000 meters. The number of persons actually affected is probably much smaller because ground water may not be contaminated at all (if any) of the sites, some of the individuals may rely on surface water or rainwater rather than on ground water, and some of the individuals and public water supplies may not have drinking water wells that are hydraulically connected to possible release sources. Also, the sample population potentially exposed through public water supplies is probably far less than estimated, because public water is frequently treated prior to consumption (possibly resulting in the removal of oil and gas waste contaminants) and because many supply systems utilize multiple sources of water, with water only at times being drawn from possibly contaminated sources. Therefore, these ratios largely overestimate the number of people actually exposed per oil and gas well and should be used to estimate the total number of people affected only with caution. The figures are intended simply to give a preliminary indication of the potentially exposed population and the distribution of that population in different distance categories.

QUANTITATIVE RISK MODELING RESULTS: RESOURCE DAMAGE

For the purposes of this study, resource damage is defined as the exceedance of pre-set threshold (i.e., "acceptable") concentrations for individual contaminants, based on levels associated with aquatic toxicity, taste and odor, or other adverse impacts. Potential ground-water and surface water damage was measured as the maximum (over the 200-year modeling time period) annual volume of contaminated water flowing past various points downgradient or downstream of the source. Only the volume of water that exceeded a damage threshold concentration was considered to be contaminated. This measure of potential ground-water and surface water damage was computed for each of three distances downgradient or downstream from a source: 60, 200, and 1,500 meters.

These estimates of resource damage supplement, but should be considered separate from, the damage cases described in Chapter IV. The resource damage results summarized here are strictly for the model scenarios considered in this analysis, which represent: (1) seepage of reserve pit wastes; (2) releases of produced water from injection well failures; and (3) direct discharge of produced water from stripper wells to streams and rivers. While these releases may be similar to some of the damage cases described in Chapter IV, no attempt was made to correlate the scenarios to any given damage case(s). In addition, Chapter IV describes damage cases from several types of releases (e.g., land application) that were not modeled as part of this quantitative risk analysis.

Potential Ground-Water Damage--Drilling Wastes

Two contaminants were modeled for ground-water resource damage associated with onsite reserve pits. These contaminants were chloride ions in concentrations above EPA's secondary maximum contaminant level and total mobile ions (TMI) in concentrations exceeding the level of total dissolved salts predicted to be injurious to sensitive and moderately sensitive crops. Chloride is highly mobile in ground water and the other ions were assumed to be equally mobile.

On a national basis, the risks of significant ground-water damage were very low for the model scenarios included in the analysis. Under the best-estimate modeling assumptions, only 2 percent of nationally weighted reserve pit scenarios were estimated to cause measurable ground-water damage at 60 meters resulting from TMI. Under the conservative modeling assumptions, less than 10 percent of reserve pits were associated with ground-water plumes contaminated by chloride and TMI at 60 meters and fewer than 2 percent at 200 meters. On a regional basis, the upper 90th percentile of the distributions for resource damage, under conservative modeling assumptions, were above zero for zones 2, 5, and 8. This zone pattern is similar to the zone pattern of noncancer human health risks from sodium. Flow field A was more heavily weighted for these three zones than for the remaining zones, and this flow field also was responsible for the highest downgradient concentrations of sodium of all the flow fields modeled.

The mobilities of chloride and total mobile salts in ground water were the same as the mobility of sodium, which was responsible for the noncancer human health risks. Thus, the effects of several pit design and environmental parameters on the volume of ground water contaminated above criteria concentrations followed trends very similar to those followed by the noncancer human health risks. These parameters included reserve pit size, net recharge, subsurface permeability, and depth to ground water. In contrast to the trend in noncancer human health risks, however, the magnitude of resource damage sometimes increased with increasing distance from the reserve pit. This is because contaminant concentrations (and thus health risks) decrease with distance traveled; however, the width of a contaminant plume (and thus the volume of contaminated water) increases up to a point with distance traveled. Eventually, however, the center line concentration of the plume falls below threshold, and the estimated volume of contaminated water at that distance falls to zero. Finally, as was the case with noncancer human health risks, only the slower aquifers were associated with significant estimates of resource damage.

Potential Ground-Water Damage--Produced Water

As they were for drilling wastes, chloride and total mobile ions were modeled to estimate ground-water resource damage associated with underground injection of produced water. Under best-estimate conditions, the risk of ground water becoming contaminated above the thresholds if injection well casing failures were to occur was negligible. Furthermore, in all but a few scenarios (approximately 1 percent of the nationally weighted scenarios), the resource damage estimates did not exceed zero under conservative assumptions. Estimated resource damage was almost entirely confined to the 60-meter modeling distance.

Grout seal failures were estimated to pose a slightly smaller risk of contaminating ground water above the chloride or TMI thresholds than injection well casing failures. In roughly 99 percent of the nationally weighted scenarios, grout seal failures never resulted in threshold exceedances, regardless of the set of conditions assumed (best-estimate vs. conservative) or the downgradient distance analyzed. Again, estimated resource damage was almost entirely confined to the 60-meter modeling distance.

In general, injection well failures were estimated to contaminate larger volumes of ground water above the damage criteria under conditions involving higher injection rates/pressures and lower ground-water velocities/flows (i.e., flow fields A, B, C, and K). The estimated TMI concentration exceeded its threshold for the low injection rate very rarely, and only out to a distance of 60 meters. Chloride and TMI threshold exceedances were limited almost exclusively to conditions involving the high injection rate or pressure. The slower velocity/lower flow ground-water settings permit less dilution (i.e., a higher probability of threshold exceedance) of constituents modeled for resource damage effects. In a trend similar to that observed for health risks, waterflood wells were estimated to contaminate larger volumes of ground water than disposal wells under conditions involving casing failures, but disposal wells were estimated to contaminate larger volumes under conditions involving grout seal failures. Finally, the resource damage estimates for injection well failures (and also for reserve pit leachate) indicate that TMI is a greater contributor to ground-water contamination than chloride. The reason for this difference is that the mobile salts concentration in the model produced water waste stream is more than three times the chloride concentration (see Table V-1), while the resource damage thresholds differ by a factor of two (see Table V-2).

Potential Surface Water Damage

EPA examined the potential for surface water damage resulting from the influx of ground water contaminated by reserve pit seepage and injection well failures, as well as surface water damage resulting from direct discharge of stripper well produced water. For all model scenarios, EPA estimated the average annual surface water concentrations of waste constituents to be below their respective thresholds at the point where they enter the surface water; that is, the threshold concentrations for various waste constituents were not exceeded even at the point of maximum concentration in surface waters. This is because the input chemical mass is diluted substantially upon entering the surface water. Surface water usually flows at a much higher rate than ground water and also allows for more complete mixing than ground water. Both of these factor suggest that there will be greater dilution in surface water than in ground water. One would expect, therefore, that the low concentrations in ground water estimated for reserve pit seepage and injection well failures would be diluted even further upon seeping into surface water.

These limited modeling results do not imply that resource damage could not occur from larger releases, either through these or other migration pathways or from releases to lower flow surface waters (i.e., streams with flows below 40 ft^3/s). In addition, surface water damages could occur during short periods (less than a year) of low stream flow or peak waste discharge, which were not modeled in this study.

EPA analyzed what a river or stream flow rate would have to be (given the model produced water concentrations and discharge rates from stripper wells) in order for contaminant concentrations in the mixing zone (assuming instantaneous and complete mixing but not other removal processes) to exceed resource damage criteria. The results of this analysis are summarized in Table V-11. As shown, the maximum concentrations of chloride, boron, sodium, and TMI in streams or rivers caused by the discharge of produced water from stripper wells would (under most modeling conditions) not exceed resource damage criteria unless the receiving stream or river was flowing at a rate below 1 ft^3/s. The exceptions are scenarios with a conservative waste stream concentration and high discharge rate. If produced water was discharged to streams or rivers under these conditions, the maximum concentrations of sodium and TMI could exceed resource damage criteria in surface waters flowing up to 5 ft^3/s. (The maximum concentrations in any surface water flowing at a greater rate would not exceed the criteria.)

The results suggest that, if produced waters from stripper wells are discharged to streams and rivers under conditions that are similar to those modeled, resource damage criteria would be exceeded only in very small streams.

ASSESSMENT OF WASTE DISPOSAL ON ALASKA'S NORTH SLOPE

In accordance with the scope of the study required by RCRA Section 8002(m), this assessment addresses only the potential impacts associated

Table V-11 Surface Water Flow Rates At Which Concentrations of Waste Stream Constituents in the Mixing Zone Will Exceed Aquatic Effects and Resource Damage Thresholds[a]

Constituent	Concentration in waste	Waste stream discharge rate: High (100 BPD)	Medium (10 BPD)	Low (1 BPD)
Sodium	Median	$\leq 0.7\ ft^3/s$[b]	$\leq 0.07\ ft^3/s$	$\leq 0.007\ ft^3/s$
	90th %	$\leq 5\ ft^3/s$	$\leq 0.5\ ft^3/s$	$\leq 0.05\ ft^3/s$
Chloride	Median	$\leq 0.2\ ft^3/s$	$\leq 0.02\ ft^3/s$	$\leq 0.002\ ft^3/s$
	90th %	$\leq 0.9\ ft^3/s$	$\leq 0.09\ ft^3/s$	$\leq 0.009\ ft^3/s$
Boron	Median	$\leq 0.06\ ft^3/s$	$\leq 0.006\ ft^3/s$	$\leq 0.0006\ ft^3/s$
	90th %	$\leq 0.8\ ft^3/s$	$\leq 0.08\ ft^3/s$	$\leq 0.008\ ft^3/s$
Total Mobile Ions	Median	$\leq 0.4\ ft^3/s$	$\leq 0.04\ ft^3/s$	$\leq 0.004\ ft^3/s$
	90th %	$\leq 2\ ft^3/s$	$\leq 0.2\ ft^3/s$	$\leq 0.02\ ft^3/s$

[a]The effect thresholds and effects considered in this analysis were as follows: Sodium-83 mg/L, which might result in toxic effects or osmoregulatory problems for freshwater aquatic organisms (note: while this threshold is based on toxicity data reported in the literature, it is dependent on several assumptions and is speculative); chloride--250 mg/L, which is EPA's secondary drinking water standard designed to prevent excess corrosion of pipes in hot water systems and to prevent objectionable tastes; boron--1 mg/L, which is a concentration in irrigation water that could damage sensitive crops (e.g., citrus trees; plum, pear, and apple trees; grapes; and avocados); and total mobile Ions--335 mg/L, which may be a tolerable level for freshwater species but would probably put them at a disadvantage in competing with brackish or marine organisms.

[b]Should be interpreted to mean that the concentration of sodium in the mixing zone would exceed the modeled effect threshold (described in footnote a) if the receiving stream or river was flowing at a rate of 0.7 ft^3/s or lower. If the stream or river was flowing at a higher rate, then the maximum concentration of sodium would not exceed the effect level.

with the management of exempt oil and gas wastes on Alaska's North Slope. It does not analyze risks or impacts from other activities, such as site development or road construction. The North Slope is addressed in a separate, qualitative assessment because readily available release and transport models for possible use in a quantitative assessment are not appropriate for many of the characteristics of the North Slope, such as the freeze-thaw cycle, the presence of permafrost, and the typical reserve pit designs.

Of the various wastes and waste management practices on the North Slope, it appears that the management of drilling waste in above-ground reserve pits has the greatest potential for adverse environmental effects. The potential for drilling wastes to cause adverse human health effects is small because the potential for human exposure is small. Virtually all produced water on the North Slope is reinjected approximately 6,000 to 9,000 feet below the land surface in accordance with discharge permits issued by the State of Alaska. The receiving formation is not an underground source of drinking water and is effectively sealed from the surface by permafrost. Consequently, the potential for environmental or human health impacts associated with produced fluids is very small under routine operating conditions.

During the summer thaw, reserve pit fluids are disposed of in underground injection wells, released directly onto the tundra or applied to roads if they meet quality restrictions specified in Alaska discharge permits, or stored in reserve pits. Underground injection of reserve pit fluids should have minor adverse effects for the same reasons as were noted above for produced waters. If reserve pit fluids are managed through the other approaches, however, there is much greater potential for adverse environmental effects.

Discharges of reserve pit fluids onto the tundra and roads are regulated by permits issued by the Alaska Department of Environmental Conservation (ADEC). In the past, reserve pit discharges have occasionally exceeded permit limitations for certain constituents. New permits, therefore, specify several pre-discharge requirements that must be met to help ensure that the discharge is carried out in an acceptable manner.

Only one U.S. Government study of the potential effects of reserve pit discharges on the North Slope is known to be complete. West and Snyder-Conn (1987), with the U.S. Fish and Wildlife Service, examined how reserve pit discharges in 1983 affected water quality and invertebrate communities in receiving tundra ponds and in hydrologically connected distant ponds. Although the nature of the data and the statistical analysis precluded a definitive determination of cause and effect, several constituents and characteristics (chromium, barium, arsenic, nickel, hardness, alkalinity, and turbidity) were found in elevated concentrations in receiving ponds when compared to control ponds. Also, alkalinity, chromium, and aliphatic hydrocarbons were elevated in hydrologically connected distant ponds when compared to controls. Accompanying these water quality variations was a decrease in invertebrate taxonomic richness, diversity, and abundance from control ponds to receiving ponds.

West and Snyder-Conn, however, cautioned that these results cannot be wholly extrapolated to present-day oil field practices on the North Slope because some industry practices have changed since 1983. For example, they state that "chrome lignosulfonate drill muds have been partly replaced by non-chrome lignosulfonates, and diesel oil has been largely replaced with less toxic mineral oil in drilling operations." Also, State regulations concerning reserve pit discharges have become increasingly stringent since the time the study was conducted. West and

Snyder-Conn additionally concluded that reserve pit discharges should be subject to standards for turbidity, alkalinity, chromium, arsenic, and barium to reduce the likelihood of biological impacts. ADEC's 1987 tundra discharge permit specifies effluent limitations for chromium, arsenic, barium, and several other inorganics, as well as an effluent limitation for settleable solids (which is related to turbidity). The 1987 permit requires monitoring for alkalinity, but does not specify an effluent limit for this parameter.

Reserve pits on the North Slope are frequently constructed above grade out of native soils and gravel. Below-grade structures are also built, generally at exploratory sites, and occasionally at newer production sites. Although the mud solids that settle at the bottom of the pits act as a barrier to fluid flow, fluids from above-ground reserve pits (when thawed) can seep through the pit walls and onto the tundra. No information was obtained on what percentage of the approximately 300 reserve pits on the North Slope are actually leaking; however, it has been documented that "some" pits do in fact seep (ARCO 1985, Standard Oil 1987). While such seepage is expected to be sufficiently concentrated to adversely affect soil, water, vegetation, and dependent fauna in areas surrounding the reserve pits, it is not known how large an area around the pits may be affected. Preliminary studies provided by industry sources indicate that seepage from North Slope reserve pits, designed and managed in accordance with existing State regulations, should not cause damage to vegetation more than 50 feet away from the pit walls (ARCO 1986, Standard Oil 1987). It is important to note that ADEC adopted regulations that should help to reduce the occurrence of reserve pit seepage and any impacts of drilling waste disposal. These regulations became effective in September 1987.

While some of the potentially toxic constituents in reserve pit liquids are known to bioaccumulate (i.e., be taken up by organisms low in the food chain with subsequent accumulation in organisms higher in the food chain), there is no evidence to conclude that bioaccumulation from reserve pit discharge or seepage is occurring. In general, bioaccumulation is expected to be small because each spring thaw brings a large onrush of water that may help flush residual contamination, and higher level consumers are generally migratory and should not be exposed for extended periods. It is recognized, however, that tundra invertebrates constitute the major food source for many bird species on the Arctic coastal plain, particularly during the breeding and rearing seasons, which coincide with the period that tundra and road discharges occur. The Fish and Wildlife Service is in the process of investigating the effects of reserve pit fluids on invertebrates and birds, and these and other studies need to be completed before conclusions can be reached with respect to the occurrence of bioaccumulation on the North Slope.

With regard to the pit solids, the walls of operating pits have slumped on rare occasions, allowing mud and cuttings to spill onto the surrounding tundra. As long as these releases are promptly cleaned up, the adverse effects to vegetation, soil, and wildlife should be temporary (Pollen 1986, McKendrick 1986).

ADEC's new reserve pit closure regulations for the North Slope contain strengthened requirements for reserve pit solids to be dewatered, covered with earth materials, graded, and vegetated. The new regulations also require owners of reserve pits to continue monitoring and to maintain the cover for a minimum of 5 years after closure. If the reserve pit is constructed below grade such that the solids at closure are at least 2 feet below the bottom of the soil layer that thaws each spring, the solids will be kept permanently frozen (a phenomenon referred to as freezeback). The solids in closed above-grade pits will also undergo freezeback if they are covered with a sufficient layer of earth material to provide insulation. In cases where the solids are kept permanently frozen, no leaching or erosion of the solid waste constituents should occur. However, ADEC's regulations do not require reserve pits to be closed in a manner that ensures freezeback. Therefore, some operators may choose to close their pits in a way that permits the solids to thaw during the spring. Even when the solids are not frozen, migration of the waste constituents will be inhibited by the reserve pit cover and the low rate of water infiltration through the solids. Nevertheless, in the long term, the cover could slump and allow increased snow accumulation in depressed areas. Melting of this snow could result in infiltration into the pit and subsequent leaching of the thawed solid waste contaminants. Also, for closed above-grade pits, long-term erosion of the cover could conceivably allow waste solids, if thawed, to migrate to surrounding areas. Periodic monitoring would forestall such possibilities.

LOCATIONS OF OIL AND GAS ACTIVITIES IN RELATION TO ENVIRONMENTS OF SPECIAL INTEREST

EPA analyzed the proximity of oil and gas activities to three categories of environments of special interest to the public: endangered and threatened species habitats, wetlands, and public lands. The results of this analysis are intended only to provide a rough approximation of the degree of and potential for overlap between oil and gas activities and these areas. The results should not be interpreted to mean that areas where oil and gas activities are located are necessarily adversely affected.

All of the 26 States having the highest levels of oil and gas activity are within the historical ranges of numerous endangered and threatened species habitats. However, of 190 counties across the U.S. identified as having high levels of exploration and production, only 13 (or 7 percent) have Federally designated critical habitats[10] within their boundaries. These 13 counties encompass the critical habitats for a total of 10 different species, or about 10 percent of the species for which critical habitats have been designated on the Federal level.

Wetlands create habitats for many forms of wildlife, purify natural waters by removing sediments and other contaminants, provide flood and storm damage protection, and afford a number of other benefits. In general, Alaska and Louisiana are the States with the most wetlands and oil and gas activity. Approximately 50 to 75 percent of the North Slope area consists of wetlands (Bergman et al. 1977). Wetlands are also abundant throughout Florida, but oil and gas activity is considerably less in that State and is concentrated primarily in the panhandle area. In addition, oil and gas activities in Illinois appear to be concentrated in areas with abundant wetlands. Other States with abundant wetlands (North Carolina, South Carolina, Georgia, New Jersey, Maine, and Minnesota) have very little onshore oil and gas activity.

For the purpose of this analysis, public lands are defined as the wide variety of land areas owned by the Federal Government and administered by the Bureau of Land Management (BLM), National Forest Service, or National Park Service. Any development on these lands must first pass through a formal environmental planning and review process. In many cases, these lands are not environmentally sensitive. National Forests, for example, are established for multiple uses, including timber development, mineral extraction, and the protection of environmental values. Public lands are included in this analysis, however, because they are considered "publicly sensitive," in the sense that they are commonly valued more highly by society than comparable areas outside

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10 Critical habitats, which are much smaller and more rigorously defined than historical ranges, are areas containing physical or biological factors essential to the conservation of the species.

their boundaries. The study focuses only on lands within the National Forest and National Park Systems because of recent public interest in oil and gas development in these areas (e.g., see Sierra Club 1986; Wilderness Society 1987).

The National Forest System comprises 282 National Forests, National Grasslands, and other areas and includes a total area of approximately 191 million acres. Federal oil and gas leases, for either exploration or production, have been granted for about 25 million acres (roughly 27 percent) of the system. Actual oil and gas activity is occurring on a much smaller acreage distributed across 11 units in eight States. More than 90 percent of current production on all National Forest System lands takes place in two units: the Little Missouri National Grassland in North Dakota and the Thunder Basin National Grassland in Wyoming.

The National Park System contains almost 80 million acres made up by 337 units and 30 affiliated areas. These units include national parks, preserves, monuments, recreation areas, seashores, and other areas. All units have been closed to future leasing of Federal minerals except for four national recreation areas where mineral leasing has been authorized by Congress and permitted under regulation. If deemed acceptable from an environmental standpoint, however, nonfederally owned minerals within a unit's boundaries can be leased.[11] Ten units (approximately 3 percent of the total) currently have active oil and gas operations within their boundaries. Approximately 23 percent of the land area made up by these ten units is currently under lease (approximately 256,000 acres); however, 83 percent of the area within the ten units (almost one million acres) is leasable. The National Park Service also has identified 32 additional units that do not have active oil and gas operations at present, but do have the potential for such activities in the future.

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[11] Nonfederally owned minerals within National Park System units exist where the Federal Government does not own all the land within a unit's boundaries or does not possess the subsurface mineral rights.

Several of these units also have acres that are under lease for oil and gas exploration, development, and production. In total, approximately 334,700 acres within the National Park System (or roughly 4 percent of the total) are currently under lease for oil and gas.

CONCLUSIONS

EPA's major conclusions, along with a summary of the main findings on which they are based, are listed below. EPA recognizes that the conclusions are limited by the lack of complete data and the necessary risk modeling assumptions. In particular, the limited amount of waste sampling data and the lack of empirical evidence on the probability of injection well failures have made it impossible to estimate precisely the absolute nationwide or regional risks from current waste management practices for oil and gas wastes. Nevertheless, EPA believes that the risk analysis presented here has yielded many useful conclusions relating to the nature of potential risks and the circumstances under which they are likely to occur.

General Conclusions

- For the vast majority of model scenarios evaluated in this study, only very small to negligible risks would be expected to occur even if the toxic chemical(s) of concern were of relatively high concentration in the wastes <u>and</u> there was a release into ground water as was assumed in this analysis. Nonetheless, the model results also show that there are realistic combinations of measured chemical concentrations (at the 90th percentile level) and release scenarios that could be of substantial concern. EPA cautions that there are other release modes not considered in this analysis that could also contribute to risks. In addition, there are almost certainly toxic contaminants in the large unsampled population of reserve pits and produced fluids that could exceed concentration levels measured in the relatively small number of waste samples analyzed by EPA.

- EPA's modeling of resource damages to surface water--both in terms of ecological impact and of resource degradation--generally did not show significant risk. This was true both for ground-water seepage and direct surface water discharge (from stripper wells) pathways for drilling pit and produced water waste streams. This conclusion holds for the range of receiving water flow rates modeled, which included only moderate (40 ft^3/s) to large (850 ft^3/s) streams. It is clear that potential damages to smaller streams would be quite sensitive to relative discharge or ground-water seepage rates.

- Of the hundreds of chemical constituents detected in both reserve pits and produced water, only a few from either source appear to be of primary concern relative to health or environmental damages. Based on an analysis of toxicological data, the frequency and measured concentrations of waste constituents in the relatively small number of sampled waste streams, and the mobility of these constituents in ground water, EPA found a limited number of constituents to be of primary relevance in the assessment of risks via ground water. Based on current data and analysis, these constituents include arsenic, benzene, sodium, chloride, cadmium, chromium, boron, and mobile salts. All of these constituents were included in the quantitative risk modeling in this study. Cadmium, chromium, and boron did not produce risks or resource damages under the conditions modeled. Note: This conclusion is qualified by the small number of sampled sites for which waste composition could be evaluated.

- Both for reserve pit waste and produced water, there is a very wide (six or more orders of magnitude) variation in estimated health risks across scenarios, depending on the different combinations of key variables influencing the individual scenarios. These variables include concentrations of toxic chemicals in the waste, hydrogeologic parameters, waste amounts and management practices, and distance to exposure points.

Drilling Wastes Disposed of in Onsite Reserve Pits

- Most of the 1,134 onsite reserve pit scenarios had very small or no risks to human health via ground-water contamination of drinking water for the conditions modeled. Under the best-estimate assumptions, there were no carcinogenic waste constituents modeled (median concentrations for carcinogens in the EPA samples were zero or below detection), and more than 99 percent of the nationally weighted reserve pit scenarios resulted in exposure to noncarcinogens (sodium, cadmium, chromium) at concentration levels below health effect thresholds. Under more conservative assumptions, including toxic constituents at 90th percentile sample concentrations, no scenarios evaluated yielded lifetime cancer risks as high as 1 in 100,000 (1×10^{-5}),[12] and only 2 percent of the nationally weighted conservative scenarios showed cancer risks greater than 1×10^{-7}. Noncancer risks were estimated by threshold exceedances for only 2 percent of nationally weighted scenarios, even when the 90th percentile concentration of sodium in the waste stream was assumed. The maximum sodium concentration at drinking water wells was estimated to be roughly 32 times the threshold for hypertension. In general, these modeling results suggest that most onsite reserve pits will present very low risks to human health through ground-water exposure pathways.

- It appears that people may be able to taste chloride in the drinking water in those scenarios with the highest cancer and noncancer risks. It is questionable, however, whether people would actually discontinue drinking water containing these elevated chloride concentrations.

- Weighting the risk results to account for different distributions of hydrogeologic variables, pit size, and exposure distance across geographic zones resulted in limited variability in risks across zones. Risk distributions for individual zones generally did not differ from the national distribution by more than one order of magnitude, except for zones 10 (West Coast) and 11B (Alaska, non-North Slope), which usually were extremely low. Note: EPA was unable to develop geographical comparisons of toxic constituent concentrations in drilling pit wastes.

- Several factors were evaluated for their individual effects on risk. Of these factors, ground-water flow field type and exposure distance had the greatest influence (several orders of magnitude); recharge rate, subsurface permeability, and pit size had less, but measurable, influence (approximately one order of magnitude). Typically, the higher risk cases occur in the context of the largest unlined pits, the short (60-meter) exposure distance, and high subsurface permeability and infiltration. Depth to ground water and presence/absence of a single synthetic liner had virtually no measurable influence over the 200-year modeling period; however, risk estimated over shorter time periods, such as 50 years, would likely be lower for lined pits compared to unlined pits, and lower for deep ground water compared to shallow ground water.

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12 A cancer risk estimate of 1×10^{-5} indicates that the chance of an individual contracting cancer over a 70-year average lifetime is approximately 1 in 100,000. The Agency establishes the cutoff between acceptable and unacceptable levels of cancer risk between 1×10^{-7} and 1×10^{-4}.

- Estimated ground-water resource damage (caused by exceedance of water quality thresholds for chloride and total mobile ions) was very limited and essentially confined to the closest modeling distance (60 meters). These resource damage estimates apply only to the pathway modeled (leaching through the bottom of onsite pits) and not to other mechanisms of potential ground-water contamination at drilling sites, such as spills or intentional surface releases.

- No surface water resource damage (caused by exceedance of thresholds for chloride, sodium, cadmium, chromium VI, or total mobile ions) was predicted for the seepage of leachate-contaminated ground water into flowing surface water. This finding, based on limited modeling, does not imply that resource damage could not occur from larger releases, either through this or other pathways of migration, or from releases to lower flow surface waters (below 40 ft^3/s).

Produced Water Disposal in Injection Wells

- All risk results for underground injection presented in this chapter assume that either a grout seal or well casing failure occurs. However, as anticipated under EPA's Underground Injection Control (UIC) regulatory program, these failures are probably low-frequency events, and the actual risks resulting from grout seal and casing failures are expected to be much lower than the conditional risks presented here. The results do not, however, reflect other possible release pathways such as migration through unplugged boreholes or fractures in confining layers, which also could be of concern.

- Only a very small minority of injection well scenarios resulted in meaningful risks to human health, due to either grout seal or casing failure modes of release of produced water to drinking water sources. In terms of carcinogenic risks, none of the best-estimate scenarios (median arsenic and benzene sample concentrations) yielded lifetime risks greater than 5 per 1,000,000 (5×10^{-6}) to the maximally exposed individual. When the 90th percentile benzene and arsenic concentrations were examined, a maximum of 35 percent of EPA's nationally weighted scenarios had risks greater than 1×10^{-7}, with up to 5 percent having cancer risks greater than 1×10^{-4} (the highest risk was 9×10^{-4}). The high cancer risk scenarios corresponded to a very short (60-meter) exposure distance combined with relatively high injection pressure/rates and a few specific ground-water flow fields (fields C and D in Table V-7).

- Noncancer health effects modeled were limited to hypertension in sensitive individuals caused by ingestion of sodium in drinking water. In the best-estimate scenarios, up to 8 percent of EPA's nationally weighted scenarios had threshold exceedances for sodium in ground-water supplies. In the conservative scenarios, where 90th percentile sodium concentrations were assumed in the injection waters, threshold exceedances in drinking water were predicted for a maximum of 22 percent of the nationally weighted scenarios. The highest sodium concentration predicted at exposure wells under conservative assumptions exceeded the threshold for hypertension by a factor of 70. The high noncancer risk scenarios corresponded to a very short (60-meter) exposure distance, high injection pressures/rates, and relatively slow ground-water velocities/low flows.

- It appears that people would not taste or smell chloride or benzene at the concentration levels estimated for the highest cancer risk scenarios, but sensitive individuals would be more likely to detect chloride or benzene tastes or odors in those scenarios with the highest noncancer risks. It is questionable, however, whether the detectable tastes or smells at these levels would generally be sufficient to discourage use of the water supply.

- As with the reserve pit risk modeling results, adjusting (weighting) the injection well results to account for differences among various geographic zones resulted in relatively small differences in risk distributions. Again, this lack of substantial variability in risk across zones may be the result of limitations of the study approach and the fact that geographic comparisons of toxic constituents in produced water was not possible.

- Of several factors evaluated for their effect on risk, exposure distance and ground-water flow field type had the greatest influence (two to three orders of magnitude). Flow rate/pressure had less, but measurable, influence (approximately one order of magnitude). Injection well type (i.e., waterflood vs. disposal) had moderate but contradictory effects on the risk results. For casing failures, high-pressure waterflood wells were estimated to cause health risks that were about 2 times higher than the risks from lower pressure disposal wells under otherwise similar conditions. However, for grout seal failures, the risks associated with disposal wells were estimated to be up to 3 times higher than the risks in similar circumstances associated with waterflood wells, caused by the higher injection rates for disposal.

- Estimated ground-water resource damage (resulting from exceedance of thresholds for chloride, boron, and total mobile ions) was extremely limited and was essentially confined to the 60-meter modeling distance. This conclusion applies only to releases from Class II injection wells, and not to other mechanisms of potential ground-water contamination at oil and gas production sites (e.g., seepage through abandoned boreholes or fractures in confining layers, leaching from brine pits, spills).

- No surface water resource damage (resulting from exceedance of thresholds for chloride, sodium, boron, and total mobile ions) was predicted for seepage into flowing surface water of ground water contaminated by direct releases from injection wells. This finding does not imply that resource damage could not occur via mechanisms and pathways not covered by this limited surface water modeling, or in extremely low flow streams.

Stripper Well Produced Water Discharged Directly into Surface Water

- Under conservative modeling assumptions, 17 percent of scenarios (unweighted) had cancer risks greater than 1×10^{-5} (the maximum cancer risk estimate was roughly 4×10^{-5}).[13] The maximum cancer risk under best-estimate waste stream assumptions was 4×10^{-7}. No exceedances of noncancer effect thresholds or surface water resource damage thresholds were predicted under any of the conditions modeled. The limited surface water modeling performed applies only to scenarios with moderate- to high-flow streams (40 to 850 ft^3/s). Preliminary analyses indicate, however, that resource damage criteria would generally be exceeded in only very small streams (i.e., those flowing at less than 5 ft^3/s), given the sampled waste stream chemical concentrations and discharge rates for stripper wells of up to 100 barrels per day.

Drilling and Production Wastes Managed on Alaska's North Slope

- Adverse effects to human health are expected to be negligible or nonexistent because the potential for human exposure to drilling waste and produced fluid contaminants on the North Slope is very small. The greatest potential for adverse environmental impacts is caused by discharge and seepage of reserve pit fluids containing toxic substances onto the tundra. A field study conducted in 1983 by the U.S. Fish and Wildlife Service indicates that tundra discharges of reserve pit fluids may adversely affect water quality and invertebrates in surrounding areas; however, the

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13 These results are unweighted because the frequency of occurrence of the parameters that define the stripper well scenarios was not estimated.

results of this study cannot be wholly extrapolated to present-day practices on the North Slope because some industry practices have changed and State regulations concerning reserve pit discharges have become increasingly more stringent since 1983. Preliminary studies from industry sources indicate that seepage from operating above-ground reserve pits on the North Slope may damage vegetation within a radius of 50 feet. The Fish and Wildlife Service is in the process of studying the effects of reserve pit fluids on tundra organisms, and these studies need to be completed before more definitive conclusions can be made with respect to environmental impacts on the North Slope.

Locations of Oil and Gas Activities in Relation to Environments of Special Interest

- All of the top 26 States that have the highest levels of onshore oil and gas activity are within the historical ranges of numerous endangered and threatened species habitats; however, of 190 counties identified as having high levels of exploration and production, only 13 (or 7 percent) have federally designated critical habitats for endangered species within their boundaries. The greatest potential for overlap between onshore oil and gas activities and wetlands appears to be in Alaska (particularly the North Slope), Louisiana, and Illinois. Other States with abundant wetlands have very little onshore oil and gas activity. Any development on public lands must first pass through a formal environmental review process and some public lands, such as National Forests, are managed for multiple uses including oil and gas development. Federal oil and gas leases have been granted for approximately 25 million acres (roughly 27 percent) of the National Forest System. All units of the National Park System have been closed to future leasing of federally owned minerals except for 4 National Recreation Areas where mineral leasing has been authorized by Congress. If deemed acceptable from an environmental standpoint, however, nonfederally owned minerals within the park boundaries can be leased. In total, approximately 4 percent of the land area in the National Park System is currently under lease for oil and gas activity.

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CHAPTER VI

COSTS AND ECONOMIC IMPACTS OF ALTERNATIVE WASTE MANAGEMENT PRACTICES

OVERVIEW OF THE COST AND ECONOMIC IMPACT ANALYSIS

This chapter provides estimates of the cost and selected economic impacts of implementing alternative waste management practices by the oil and gas industry. The industry's current or "baseline" practices are described in Chapter III. In addition to current practices, a number of alternatives are available. Some of these offer the potential for higher levels of environmental control. Section 8002(m) of RCRA requires an assessment of the cost and impact of these alternatives on oil and gas exploration, development, and production.

This chapter begins by providing cost estimates for baseline and alternative waste management practices. The most prevalent current practices are reserve pit storage and disposal for drilling wastes and Class II deep well injection for produced water. In addition, several other waste management practices are included in the cost evaluation. The cost estimates for the baseline and alternative waste management practices are presented as the cost per unit of waste disposal (e.g., cost per barrel of drilling waste, cost per barrel of produced water). These unit cost estimates allow for a comparison among disposal methods and are used as input information for the economic impact analysis.

After establishing the cost of baseline and alternative practices on a unit-of-waste basis, the chapter expands its focus to assess the impact of higher waste management costs both on individual oil and gas projects and on the industry as a whole. For the purpose of this assessment, three hypothetical regulatory scenarios for waste management are defined. Each scenario specifies a distinct set of alternative environmentally protective waste management practices for oil and gas projects that generate potentially hazardous waste. Projects that do not generate hazardous waste may continue to use baseline practices under this approach.

After the three waste management scenarios have been defined, the remainder of the chapter provides estimates of their cost and economic impact. First, the impact of each scenario on the capital and operating cost and on the rate of return for representative new oil and gas projects is estimated. Using these cost estimates for individual projects as a basis, the chapter then presents regional- and national-level cost estimates for the waste management scenarios.

The chapter then describes the impact of the waste management scenarios on existing projects (i.e., projects that are already in production). It provides estimates of the number of wells and the amount of current production that would be shut down as a result of imposing alternative waste management practices under each scenario. Finally, the chapter provides estimates of the long-term decline in domestic production brought about by the costs of the waste management scenarios and estimates of the impact of that decline on the U.S. balance of payments, State and Federal revenues, and other selected economic aggregates.

The analysis presented in this chapter is based on the information available to EPA in November 1987. Although much new waste generation and waste management data was made available to this study, both by EPA and the American Petroleum Institute, certain data limitations did restrict the level of analysis and results. In particular, data on waste generation, management practices, and other important economic parameters were generally available only in terms of statewide or nationwide averages. Largely because of this, the cost study was conducted using "average regional projects" as the basic production unit of analysis. This lack of desired detail could obscure special attributes of both marginal and above average projects, thus biasing certain impact effects, such as the number of well closures.

The scope of the study was also somewhat limited in other respects. For example, not all potential costs of alternative waste management under the RCRA amendments could be evaluated, most notably the land ban and corrective action regulations currently under development. The Agency recognizes that this could substantially understate potential costs of some of the regulatory scenarios studied. The analysis was able to distinguish separately between underground injection of produced water for disposal purposes and injection for waterflooding as a secondary or enhanced energy recovery method. However, it was not possible during the course of preparing this report to evaluate the costs or impacts of alternative waste management regulations on tertiary (chemical, thermal, and other advanced EOR) recovery, which is becoming an increasingly important feature of future U.S. oil and gas production.

COST OF BASELINE AND ALTERNATIVE WASTE MANAGEMENT PRACTICES

Identification of Waste Management Practices

The predominant waste management practices currently employed by the oil and gas industry are described in Chapter III of this report. For drilling operations, wastes are typically stored in an unlined surface impoundment during drilling. After drilling, the wastes are dewatered, either by evaporation or vacuum truck, and buried onsite. Where vacuum trucks are used for dewatering, the fluids are removed for offsite disposal, typically in a Class II injection well. For production operations, the predominant disposal options are injection into a Class II onsite well or transportation to an offsite Class II disposal facility. Where onsite injection is used, the Class II well may be used for disposal only or it may be used to maintain pressure in the reservoir for enhanced oil recovery.

In addition to the above disposal options, a number of additional practices are considered here. Some of these options are fairly common (Table VI-1). For example, 37 percent of current drill sites use a lined disposal pit; 12 percent of production sites in the lower 48 States (Lower 48) discharge their produced water to the surface. Other disposal options considered here (e.g., incineration) are not employed to any significant extent at present.

For drilling waste disposal, nine alternative practices were reviewed for the purpose of estimating comparative unit costs and evaluating subsequent cost-effectiveness in complying with alternative regulatory options:

1. Onsite unlined surface impoundment;
2. Onsite single-synthetic-liner surface impoundment;
3. Offsite single-synthetic-liner surface impoundment;
4. Offsite synthetic composite liner with leachate collection (SCLC), Subtitle C design;
5. Landfarming consistent with current State oil and gas field regulations;
6. Landfarming consistent with RCRA Subtitle C requirements;
7. Waste solidification;
8. Incineration; and
9. Volume reduction.

Table VI-1 Summary of Baseline Disposal Practices, by Zone, 1985

Zone	Drilling waste disposal (percent of drill sites)		Produced water disposition (percent of produced waters)		
				Class II Injection	
	Unlined facilities	Lined facilities	Surface discharge	EOR	Disposal
Appalachian	23	77	50	25	25
Gulf	89	11	34	11	55
Midwest	47	53	0	91	9
Plains	49	51	0	38	62
Texas/ Oklahoma	60	40	4	69	27
Northern Mountain	65	35	12	45	42
Southern Mountain	50	50	0	84	16
West Coast	99	1	23	54	23
Alaska	67	33	0	71	29
Total U.S.	63	37	11	59	28
Lower 48 States	63	37	12	60	28

Sources: Drilling waste and produced water disposal information from API, 1987a except for produced water disposal percents for the Appalachian zone, which are based on personal communications with regional industry sources.

NOTE: Produced water disposition percents for total U.S. and Lower 48 are based on survey sample weights. Weighting by oil production results in a figure of 9 percent discharge in the Lower 48 (API 1987b).

In addition to these disposal options, costs were also estimated for ground-water monitoring and general site management for waste disposal sites. These latter practices can be necessary adjunct requirements for various final disposal options to enhance environmental protection.

For produced water, two alternative practices were considered in the cost analysis: Class I injection wells and Class II injection wells. Both classes may be used for water disposal or for enhanced energy recovery waterflooding. They may be located either onsite or, in the case of disposal wells, offsite. To depict the variation in use patterns of these wells, cost estimates were developed for a wide range of injection capacities.

Cost of Waste Management Practices

For each waste disposal option, engineering design parameters of representative waste management facilities were established for the purpose of costing (Table VI-2). For the baseline disposal methods, parameters were selected to typify current practices. For waste management practices that achieve a higher level of environmental control than the most common baseline practices, parameters were selected to typify the best (i.e., most environmentally protective) current design practices. For waste management practices that would be acceptable for hazardous waste under Subtitle C of RCRA, parameters were selected to represent compliance with these regulations as they existed in early 1987.

Capital and operating and maintenance (O&M) costs were estimated for each waste management practice based on previous EPA engineering cost documents and tailored computer model runs, original contractor engineering cost estimates, vendor quotations, and other sources.[1] Capital costs were annualized using an 8 percent discount rate, the

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[1] See footnotes to Tables VI-3 and VI-4 and Eastern Research Group 1987 for a detailed source list.

Table VI-2 Summary of Engineering Design Elements for Baseline and Alternative Waste Management Practices

Alternative	Capital costs	O & M costs	Closure costs	Post-closure costs
Unlined pit	• Pit excavation (0.25 acre) • Clearing and grubbing • Contingency • Contractor fee	• Negligible	• Pit burial (earth fill only) • Contingency • Contractor fee	
One-liner pit (waste buried on site)	• Clearing and grubbing • Pit excavation (0.25 acre) • Berm construction (gravel and vegetation) • 30-mil synthetic liner • Liner protection (geotextile subliner) • Engineering, contractor, and inspection fee • Contingency	• Negligible	• Pit burial (earth fill) • Capping - 30-mil PVC synthetic membrane - topsoil • Revegetation • Engineering, contractor, and inspection fee • Contingency	
Offsite one-liner facility	• Pit excavation (15 acres) • Same costs as onsite one-liner pit with addition of: - land cost - utility site work - pumps - spare parts - dredging equipment - inlet/outlet structures - construction and field expense	• Operating labor - clerical staff - foremen • Maintenance labor and supplies • Utilities • Plant overhead • Dredging	• Same costs as onsite one-liner pit • Solidification • Free liquid removal and treatment	

Table VI-2 (continued)

Alternative	Capital costs	O & M costs	Closure costs	Post-closure costs
Offsite SCLC facility	• Pit excavation (15 acres) • Same costs as commercial one-liner pit with the addition of: - additional pit liners - clay liner replaces geotextile subliner	• Same costs as commercial one-liner pit	•Same costs as onsite one-liner pit with addition of synthetic cap • Equipment decontamination	(See ground-water monitoring and site management)
Ground water monitoring and site management	• Ground-water monitoring wells • Leachate collection system - drainage tiles - leachate collection layer (sand or gravel) for single-liner case only - leachate collection liner for single-liner case only • Signs/fencing • RCRA permitting (for RCRA scenario)	• Ground-water monitoring wells sampling and laboratory fees • Leachate treatment	• Soil poisoning (to prevent disruption by long-rooted plants) • Cover drainage tile - collection layer (sand or gravel) - geotextile filter fabric in one-liner pit • Monitoring • Certification, supervision	• Monitoring well sampling • Leachate treatment • Notice to local authorities • Notation on property deed • Facility inspection • Maintenance and repair • Cover replacement • Engineering and inspection fees • Contingency
Offsite, multiple-application landfarming	• Land cost • Land clearing cost • Building cost • Lysimeter cost (RCRA scenario) • Cluster wells (RCRA scenario)	• Labor • Ground-water monitoring • Soil core cost • Maintenance • Utilities • Insurance, taxes, and G & A	• Revegetation • Testing	• Land authority and property deed cost • Ground-water monitoring cost • Soil core cost • Erosion control cost • Vegetative cover cost

Table VI-2 (continued)

Alternative	Capital costs	O & M costs	Closure costs	Post-closure costs
Offsite, multiple-application landfarming (continued)	• Wind dispersal control (RCRA scenario) • Storage tanks • Engineering and inspection • Contingency • Retention pond (RCRA scenario) • Berms (RCRA scenario)			• Engineering and inspection costs • Contingency
Volume reduction	• Equipment rental - mechanical or vacuum separation equipment • Tanks	• Chemicals • Labor		
Injection (Class II)	• Convert existing well to disposal well - completion rig contract - drilling fluids - cementing - logging and perforating - stimulation - liner and tubing • Site work/building • Holding tanks • Skim tanks • Filters and pumps • Pipelines	• Labor • Chemicals • Electricity • Filters • Disposal of filtrates • Pump maintenance • Pressure tests • Liability costs	• Plug and abandon	

Table VI-2 (continued)

Alternative	Capital costs	O & M costs	Closure costs	Post-closure costs
Injection (Class I)	• Drill new well - drilling rig contract - completion rig contract - cementing - logging and perforating - site preparation - casing - liner - tubing • Storage tanks • Annular fluid tank • Filters • Pumps • Pipelines • Site work/buildings • RCRA permit cost (RCRA scenario)	• Same costs as Class II wells with addition of: - tracer survey - cement bond log - pipe evaluation - disposal of filtrate in hazardous waste facility	• Plug and abandon	

approximate after-tax real cost of capital for this industry. Annualized capital costs were then added to O&M costs to compute the total annual costs for typical waste management unit operations. Annual costs were divided by annual waste-handling capacity (in barrels) to provide a cost per barrel of waste disposal. Both produced water disposal costs and drilling waste (i.e., muds and cuttings) disposal costs are expressed on a dollars-per-barrel basis.

The average engineering unit cost estimates for drilling wastes are presented in Table VI-3 for each region and for a composite of the Lower 48. Regional cost variations were estimated based on varying land, construction, and labor costs among regions. The costs for the Lower 48 composite are estimated by weighting regional cost estimates by the proportion of production occurring in each region. (Throughout the discussion that follows, the Lower 48 composite will be referenced to illustrate the costs and impacts in question.)

For the Lower 48 composite, the drilling waste disposal cost estimates presented in Table VI-3 range from $2.04 per barrel for onsite, unlined pit disposal to $157.50 per barrel for incineration. Costs for the disposal options are significantly higher for Alaska because of the extreme weather conditions, long transportation distances from population and material centers to drill sites, high labor costs, and other unique features of this region.

Costs for produced water are presented in Table VI-4. Disposal costs include injection costs, as well as transport, loading, and unloading charges, where appropriate. Injection for EOR purposes occurs onsite in either Class II or Class I wells. Class II disposal occurs onsite in all zones except Appalachia. Class I disposal occurs offsite except for the Northern Mountain and Alaska zones. Well capacities and transport distances vary regionally depending on the volume of water production and the area under production.

Table VI-3 Unit Costs of Drilling Waste Disposal Options, by Zone (Dollars per Barrel of Waste, 1985 Basis)

	Zone								
Disposal option	Appalachian	Gulf	Midwest	Plains	Texas/ Oklahoma	Northern Mountain	Southern Mountain	West Coast	Alaska	Lower 48
Surface impoundment[a]										
Unlined (0.25 acre)	$ 2.09	$ 1.98	$ 2.00	$ 1.98	$ 2.10	$ 2.00	$ 2.00	$ 2.04	$ 2.69	$ 2.04
Single-liner (0.25 acre)	4.62	4.32	4.35	4.29	4.63	4.35	4.35	4.46	6.16	4.46
SCLC (15 acres)	18.26	12.41	25.61	19.54	11.66	19.73	20.69	27.54	20.27	15.52
Landfarming[b]										
Current	13.21	12.06	12.41	15.91	17.01	16.14	15.99	16.42	N.E.	15.47
Subtitle C	30.23	31.58	28.94	39.14	40.31	36.45	36.38	38.45	N.E.	37.12
Solidification[c]	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	N.E.	8.00
Incineration[d]	157.50	157.50	157.50	157.50	157.50	157.50	157.50	157.50	N.E.	157.50
Volume reduction and offsite single-liner disposal[e]	15.16	3.18	17.24	9.50	5.83	5.40	6.15	21.87	5.67	6.74
Volume reduction and offsite SCLC disposal[e]	19.27	7.94	25.50	15.94	9.91	11.90	12.93	30.71	12.57	11.95

N.E. = Not estimated; disposal method not practical and/or information not available for Alaska.

[a]Source: Pope Reid Associates 1985a, 1985b, 1987a; costs for SCLC disposal include transportation charges.
[b]Source: Pope Reid Associates 1987b.
[c]Source: Erlandson 1986; Webster 1987; Tesar 1986; Camp, Dresser & McKee 1986; Hanson and Jones 1986; Cullinane et al. 1986; North American Environmental Service 1985.
[d]Source: USEPA 1986.
[e]Source: Slaughter 1987; Rafferty 1987. Costs include equipment rental and transport and disposal of reduced volume of waste. All costs are allocated over the original volume of waste so that per-barrel costs of waste disposal are comparable to the other cost estimates in the table.

Table VI-4 Unit Costs of Underground Injection of Produced Water, by Zone (Dollars per Barrel of Water)

Zone	Class II injection Disposal	Class II injection EOR	Class I injection[a] Disposal	Class I injection[a] EOR
Appalachian[b]	$1.26-1.33	$0.75	$2.45	$6.12
Gulf	0.10	0.23	0.84	1.35
Midwest	0.29	0.13	1.14	0.84
Plains	0.14	0.19	0.86	1.21
Texas/Oklahoma	0.11	0.14	0.96	0.76
Northern Mountain	0.01	0.14	0.40	0.58
Southern Mountain	0.07	0.14	1.05	0.67
West Coast	0.04	0.05	0.72	0.25
Alaska	0.05	0.41	1.28	2.15
Lower 48 States	0.10	0.14	0.92	0.78

[a] Disposal costs for Class I injection include transportation and loading/unloading charges except for the Northern Mountain zone and Alaska, where onsite disposal is expected to occur.

[b] Class II disposal costs for Appalachian zone includes transport and loading/unloading charges. Lower estimate is for intermediate scenarios; higher estimate is for baseline practice due to change in transport distances. For all other zones, Class II disposal is assumed to occur onsite.

Sources: Tilden 1987a, 1987b.

NOTE: Base year for costs is 1985.

Produced water disposal costs range from $0.01 to $1.33 per barrel for Class II disposal and EOR injection and from $0.40 to $6.12 per barrel for Class I disposal and EOR injection. Costs for Class I facilities are substantially higher because of the increased drilling completion, monitoring, and surface equipment costs associated with waste management facilities that accept hazardous waste.

The transportation of waste represents an additional waste management cost for some facilities. Transportation of drilling or production waste for offsite centralized or commercial disposal is practiced now by some companies and has been included as a potential disposal option in the waste management scenarios. Drilling waste transport costs range from $0.02 per barrel/mile for nonhazardous waste to $0.06 per barrel/mile for hazardous waste. Produced water transport costs range from $0.01 per barrel/mile (nonhazardous) to $0.04 per barrel/mile (hazardous). Distances to disposal facilities were estimated based on the volume of wastes produced, facility capacities, and the area served by each facility. Waste transportation also involves costs for loading and unloading.

WASTE MANAGEMENT SCENARIOS AND APPLICABLE WASTE MANAGEMENT PRACTICES

In order to determine the potential costs and impacts of changes in oil and gas waste disposal requirements, three waste management scenarios have been defined. The scenarios have been designed to illustrate the cost and impact of two hypothetical additional levels of environmental control in relation to current baseline practices. EPA has not yet identified, defined, or evaluated its regulatory options for the oil and gas industry; therefore, it should be noted that these scenarios do not represent regulatory determinations by EPA. A regulatory determination will be made by EPA following the Report to Congress.

Baseline Scenario

The Baseline Scenario represents the current situation. It encompasses the principal waste management practices now permitted under State and Federal regulations. Several key features of current practice for both drilling waste and produced water were summarized in Table VI-1, and the distribution of disposal practices shown in Table VI-1 is the baseline assumption for this analysis.

Intermediate Scenario

The Intermediate Scenario depicts a higher level of control. Operators generating wastes designated as hazardous are subject to requirements more stringent than those in the Baseline Scenario. An exact definition of "hazardous" has not been formulated for this scenario. Further, even if a definition were posited (e.g., failure of the E.P. toxicity test), available data are insufficient to determine the proportion of the industry's wastes that would fail any given test. Pending an exact regulatory definition of "hazardous" and the development of better analytical data, a range of alternative assumptions has been employed in the analysis. In the Intermediate 10% Scenario, the Agency assumed, for the purpose of costing, that 10 percent of oil and gas projects generate hazardous waste and in the Intermediate 70% Scenario that 70 percent of oil and gas projects generate hazardous waste.

For drilling wastes designated hazardous, operators would be required to use a single-synthetic-liner facility, landfarming with site management (as defined in Table VI-2), solidification, or incineration. Operators would select from these available compliance measures on the basis of lowest cost. Since a substantial number of operators now employ a single synthetic liner in drilling pits, only those sites not using a liner would be potentially affected by the drilling waste requirements of the Intermediate Scenario.

For produced waters, the Intermediate Scenario assumes injection into Class II facilities for any produced water that is designated hazardous. Operators now discharging waste directly to water or land (approximately 9 to 12 percent of all water) would be required to use a Class II facility if their wastes were determined to be hazardous.

"Affected operations" under a given scenario are those oil and gas projects that would have to alter their waste management practices and incur costs to comply with the requirements of the scenario. For example, in the Intermediate 10% Scenario, it is assumed that only 10 percent of oil and gas projects generate hazardous waste. For drilling, an estimated 63 percent of oil and gas projects now use unlined facilities and are therefore potentially affected by the requirements of the scenario. Since 10 percent of these projects are assumed to generate hazardous waste, an estimated 6.3 percent of the projects are affected operations, which are subject to higher disposal costs.

The Subtitle C Scenario

In the Subtitle C Scenario, wastes designated as hazardous are subject to pollution control requirements consistent with Subtitle C of RCRA. For drilling wastes, those wastes that are defined as hazardous must be disposed of in a synthetic composite liner with leachate collection (SCLC) facility employing site management and ground-water monitoring practices consistent with RCRA Subtitle C, a landfarming facility employing Subtitle C site management practices, or a hazardous waste incinerator. In estimating compliance costs EPA estimated that a combination of volume reduction and offsite dedicated SCLC disposal would be the least-cost method for disposal of drilling waste. For production wastes, those defined as hazardous must be injected into Class I disposal or EOR injection wells.

Since virtually no drilling or production operations currently use Subtitle C facilities or Class I injection wells in the baseline, all projects that generate produced water are potentially affected. In the Subtitle C 10% Scenario, 10 percent of these projects are assumed to be affected; in the Subtitle C 70% Scenario, 70 percent of these projects are affected. The Subtitle C Scenario, like the Intermediate Scenario, does not establish a formal definition of "hazardous"; nor does it attempt to estimate the proportion of wastes that would be hazardous under the scenario. As with the Intermediate Scenario, two assumptions (10 percent hazardous, 70 percent hazardous) are employed, and a range of costs and impacts is presented.

This Subtitle C Scenario does not, however, impose all possible technological requirements of the Solid Waste Act Amendments, such as the land ban and corrective action requirements of the Hazardous Solid Waste Amendments (HSWA), for which regulatory proposals are currently under development in the Office of Solid Waste. Although the specific regulatory requirements and their possible applications to oil and gas field practices, especially deep well injection practices, were not sufficiently developed to provide sufficient guidelines for cost evaluation in this report, the Agency recognizes that the full application of these future regulations could substantially increase the costs and impacts estimated for the Subtitle C Scenario.

The Subtitle C-1 Scenario

The Subtitle C-1 Scenario is exactly the same as the Subtitle C Scenario, except that produced water used in waterfloods is considered part of a production process and is therefore exempt from more stringent (i.e., Class I) control requirements, even if the water is hazardous. As shown in Table VI-1, approximately 60 percent of all produced water is used in waterfloods. Thus, only about 40 percent of produced water is potentially affected under the Subtitle C-1 Scenario. The requirements of the Subtitle C-1 Scenario for drilling wastes are exactly the same as those of the Subtitle C Scenario. As with the other scenarios, alternative assumptions of 10 and 70 percent hazardous are employed in the Subtitle C-1 Scenario.

Summary of Waste Management Scenarios

Table VI-5 summarizes the major features of all the waste management scenarios. It identifies acceptable disposal practices under each scenario and the percent of wastes affected under each scenario. The Subtitle C 70% Scenario enforces the highest level of environmental control in waste management practices, and it affects the largest percent of facilities.

COST AND IMPACT OF THE WASTE MANAGEMENT SCENARIOS FOR TYPICAL NEW OIL AND GAS PROJECTS

Economic Models

An economic simulation model, developed by Eastern Research Group (ERG) and detailed in the Technical Background Document (ERG 1987), was employed to analyze the impact of waste management costs on new oil and gas projects. The economic model simulates the performance and measures the profitability of oil and gas exploration and development projects both before and after the implementation of the waste management scenarios. For the purposes of this report, a "project" is defined as a single successful development well and the leasing and exploration activities associated with that well. The costs for the model project include the costs of both the unsuccessful and the successful leasing and exploratory and development drilling required, on average, to achieve one successful producing well.

Table VI-5 Assumed Waste Management Practices for Alternative Waste Management Scenarios

Waste management scenario	Drilling wastes: Disposal method	Drilling wastes: Potentially affected operations	Produced waters: Disposal method	Produced waters: Potentially affected operations
Baseline	Unlined surface impoundment Lined surface impoundment	N.A.	Class II injection Surface discharge	N.A.
Intermediate	Baseline practices for nonhazardous wastes For hazardous wastes: - Lined surface impoundment - Landfarming with site management - Solidification - Incineration	Facilities not now using liners: approximately 63% of total[a]	Baseline practices for nonhazardous wastes Class II injection for hazardous wastes	Facilities not now using Class II injection: approximately 20% of total[d]
Subtitle C	Baseline practices for nonhazardous wastes For hazardous wastes: - SCLC impoundment with Subtitle C site management - Landfarming with Subtitle C site management - Hazardous waste incineration	All facilities[b]	Baseline practices for nonhazardous wastes Class I injection for hazardous wastes	All facilities[e]
Subtitle C-1	Same as Subtitle C scenario	Same as Subtitle C scenario[c]	Baseline practices for nonhazardous wastes For hazardous wastes: - Class I injection for nonwaterfloods - Class II injection for waterfloods	Facilities not now waterflooding: approximately 40% of total[f]

[a] In the Intermediate 10% Scenario, 10% of the 63%, or 6.3%, are assumed to be hazardous; in the Intermediate 70% Scenario, 70% of the 63%, or 44.1%, are assumed to be hazardous.

[b] In the Subtitle C 10% Scenario, 10% of the 100%, or 10.0%, are assumed to be hazardous; in the Subtitle C 70% Scenario, 70% of the 100%, or 70.0%, are assumed to be hazardous.

[c] In the Subtitle C-1 10% Scenario, 10% of the 100%, or 10.0%, are assumed to be hazardous; in the Subtitle C-1 70% Scenario, 70% of the 100%, or 70.0%, are assumed to be hazardous.

[d] In the Intermediate 10% Scenario, 10% of the 20%, or 2.0%, are assumed to be hazardous; in the Intermediate 70% Scenario, 70% of the 20%, or 14.0%, are assumed to be hazardous.

[e] In the Subtitle C 10% Scenario, 10% of the 100%, or 10.0%, are assumed to be hazardous; in the Subtitle C 70% Scenario, 70% of the 100%, or 70.0%, are assumed to be hazardous.

[f] In the Subtitle C-1 10% Scenario, 10% of the 40%, or 4.0%, are hazardous and not exempt because of waterflooding. In the Subtitle C-1 70% Scenario, 70% of the 40%, or 28.0%, are hazardous and not exempt because of waterflooding.

For this study, model projects were defined for oil wells (with associated casinghead gas) in the nine active oil and gas zones and for a Lower 48 composite. Model gas projects were defined for the two most active gas-producing zones (the Gulf and Texas/Oklahoma zones). Thus, 12 model projects have been analyzed. The Technical Background Document for the Report to Congress provides a detailed description of the assumptions and data sources underlying the model projects.

A distinct set of economic parameter values is estimated for each of the model projects, providing a complete economic description of each project. The following categories of parameters are specified for each project:

1. Lease Cost: initial payments to Federal or State governments or to private individuals for the rights to explore for and to produce oil and gas.
2. Geological and Geophysical Cost: cost of analytic work prior to drilling.
3. Drilling Cost per Well.
4. Cost of Production Equipment.
5. Discovery Efficiency: the number of wells drilled for one successful well.
6. Production Rates: initial production rates of oil and gas and production decline rates.
7. Operation and Maintenance Costs.
8. Tax Rates: Rates for Federal and State income taxes, severance taxes, royalty payments, depreciation, and depletion.
9. Price: wellhead selling price of oil and gas (also called the "first purchase price" of the product).
10. Cost of Capital: real after-tax rate of return on equity and borrowed investment capital for the industry.
11. Timing: length of time required for each project phase (i.e., leasing, exploration, development, and production).

The actual parameter values for the 12 model projects are summarized in Table VI-6.

For each of the 12 model projects, the economic performance is estimated before (i.e., baseline) and after each waste management scenario has been implemented. Two measures of economic performance are employed in the impact assessment presented here. One is the after-tax rate of return. The other is the cost of production per barrel of oil (here defined as the cost of the resources used in production, including profit to the owners of capital, excluding transfer payments such as royalties and taxes). A number of other economic output parameters are described in the Technical Background Document.

Quantities of Wastes Generated by the Model Projects

To calculate the waste management costs for each representative project, it was necessary to develop estimates of the quantities of drilling and production wastes generated by these facilities. These estimates, based on a recent API survey, are provided in Table VI-7. Drilling wastes are shown on the basis of barrels of waste per well. Production wastes are provided on the basis of barrels of waste per barrel of oil.

For the Lower 48 composite, an estimated 5,170 barrels of waste are generated for each well drilled. For producing wells, approximately 10 barrels of water are generated for every barrel of oil. This latter statistic includes waterflood projects, some of which operate at very high water-to-oil ratios.

Model Project Waste Management Costs

Model project waste management costs are estimated for the baseline and for each waste management scenario using the cost data presented in

Table VI-6 Economic Parameters of Model Projects for U.S. Producing Zones
(All Costs in Thousands of 1985 Dollars, Other Units as Noted)

Parameter	Appalachian	Gulf	Gulf	Midwest	Plains	Texas/ Oklahoma	Texas/ Oklahoma	Northern Mountain	Southern Mountain	West Coast	Alaska	Lower 48 States
Production	Oil/Gas	Oil/Gas	Gas	Oil/Gas	Oil/Gas	Oil/Gas	Gas	Oil/Gas	Oil/Gas	Oil/Gas	Oil/Gas	Oil/Gas
Yr of first prod.	1	1	1	1	1	1	1	2	1	1	10	1
Lease cost	1.146	19.296	154.368	2.509	2.080	11.200	22.400	4.992	2.251	33.178	161.056	14.877
G & G expense	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%
Well cost	63.911	244.276	640.146	122.138	186.347	246.324	727.636	421.142	492.053	160.995	3,207.388	248.607
Disc. efficiency	85%	59%	59%	51%	52%	71%	71%	55%q	72%	90%	88%	69%
Infrastructure cost	45.000	73.183	35.297	60.788	81.855	86.820	39.824	102.662	109.357	82.560	45,998.400	83.952
O & M costs (per yr)	4.500	13.349	18.486	11.807	14.529	15.114	21.048	17.015	17.781	13.370	690.900	14.463
Initial prod. rates												
Oil (bbl/day)	4	60	0	16	26	37	0	53	32	35	3700	41
Gas (Mcf/day)	16	82	1295	15	34	69	1038	72	69	0	686	57
Prod. decline rates	9%	19%	19%	17%	19%	12%	12%	13%	13%	7%	9%	12%
Federal corp. tax	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%
State corp. tax	0%	8%	8%	4%	6.75%	5%	5%	0%	6%	9.35%	9.40%	6.14%
Royalty rate	18.75%	18.75%	18.75%	12.50%	12.50%	20.00%	20.00%	12.50%	16.00%	18.75%	14.30%	18.24%
Severance tax												
Oil	0.5%	12.5%	12.5%	0%	8%	7%	7%	6%	4%	0.14%	a	6.67%
Gas	1.5%	4.25%	4.25%	4.84%	0%	8%	7%	7%	6%	4%	0.14%	a
Wellhead price												
Oil ($/bbl)	$20.90	$21.65	$21.65	$22.11	$21.14	$22.03	$22.03	$20.74	$21.16	$18.38	$16.37	$20.00
Gas ($/Mcf)	$ 2.00	$ 1.99	$ 1.99	$ 2.03	$ 1.43	$ 1.58	$ 1.58	$ 1.77	$ 1.98	$ 2.21	$ 0.49	$ 1.65

[a] Tax based on formula in tax code, not a flat percentage.

Source: ERG 1987.

Table VI-7 Average Quantities of Waste Generated, by Zone

Model project/ zone	Drilling waste barrels/well	Produced water (barrels/barrel of oil)
Appalachian	2,344	2.41
Gulf	10,987	8.42
Midwest	1,853	23.61
Plains	3,623	9.11
Texas/Oklahoma	5,555	10.62
Northern Mountain	8,569	12.30
Southern Mountain	7,153	7.31
West Coast	1,414	8.05
Alaska	7,504	0.15
Lower 48 States	5,170	9.98
Gulf (gas only)	10,987	17.17[a]
Texas/Oklahoma (gas only)	5,555	17.17[a]

[a] Barrels of water per million cubic feet of natural gas.

Sources: API 1987a; Flannery and Lannan 1987.

Tables VI-3 and VI-4 and the waste quantity data shown in Table VI-7. For each model project, waste management costs are calculated for each waste management scenario.

For each model project and scenario, the available compliance methods were identified (Table VI-5). Cost estimates for all available compliance methods, including transportation costs for offsite methods, were developed based on the unit cost factors (Tables VI-2 and VI-3) and the waste quantity estimates (Table VI-7). Each model facility was assumed to have selected the lowest cost compliance method. Based on compliance cost comparisons, presented in more detail in the Technical Background Document, the following compliance methods are employed by affected facilities under the waste management scenarios:

Intermediate Scenario

1. Drilling wastes - single-liner onsite facility; volume reduction and transport to offsite single-liner facility if cost-effective.

2. Production wastes - Class II onsite facility.

Subtitle C Scenario

1. Drilling wastes - transport to offsite SCLC facility with site management and with volume reduction if cost-effective.

2. Production wastes - for waterfloods, onsite injection in Class I facility; for nonwaterfloods, transport and disposal in offsite Class I facility.

Subtitle C-1 Scenario

1. Drilling wastes - transport to offsite SCLS facility with site management and with volume reduction if cost-effective.

2. Production wastes - waterfloods exempt; for nonwaterfloods, transport and injection in offsite Class I facility.

For each model facility under each scenario, the least-cost compliance method was assumed to represent the cost of affected projects. Costs for unaffected projects were estimated based on the cost of baseline practices. Weighted average costs for each model under each scenario (shown in Tables VI-8 and VI-9) incorporate both affected and unaffected projects. For example, in the Subtitle C 70% Scenario, while 70 percent of projects must dispose of drilling wastes in Subtitle C facilities, the other 30 percent can continue to use baseline practices. The weighted average cost is calculated as follows:

Project category	Percentage of projects	Drilling waste disposal cost	Weighted cost
Affected operations	70%	$61,782	$43,248
Unaffected operations	30%	$15,176	$ 4,552
Weighted average			$47,800

For drilling wastes, the weighted average costs range from $15,176 per well in the Baseline to $47,800 per well in the RCRA Subtitle C 70% case. Thus, the economic analysis assumes that each well incurs an additional $32,624 under the RCRA Subtitle C 70% Scenario. For produced water, costs per barrel of water disposed of range from $0.11 in the Baseline to $0.62 in the RCRA Subtitle C 70% Scenario. Thus, there is an additional cost of $0.51 per barrel of water under this scenario.

Impact of Waste Management Costs on Representative Projects

The new oil and gas projects incur additional costs under the alternative waste management scenarios for both drilling and production waste management. By incorporating these costs into the economic model simulations, the impact of these costs on financial performance of typical new oil and gas projects is assessed. These impacts are presented in Tables VI-10 and VI-11.

As shown in Table VI-10, the internal rate of return can be substantially affected by waste management costs, particularly in the Subtitle C 70% Scenario. From a base case level of 28.9 percent, model

Table VI-8 Weighted Average Regional Costs of Drilling Waste Management for Model Projects Under Alternative Waste Management Scenarios (Dollars per Well)

Model project/ zone	Baseline	Intermediate 10%	Intermediate 70%	Subtitle C 10% and Subtitle C-1 10%	Subtitle C 70% and Subtitle C-1 70%
Appalachian	$ 9,465	$ 9,602	$10,420	$12,799	$ 32,801
Gulf	24,582	25,756	32,796	30,848	68,440
Midwest	6,014	6,219	7,447	10,138	34,880
Plains	11,442	11,852	14,312	16,073	43,858
Texas/Oklahoma	17,398	18,258	23,418	21,163	43,755
Northern Mountain	24,186	25,495	33,348	31,965	78,636
Southern Mountain	22,711	23,511	28,594	29,689	71,555
West Coast	2,919	3,258	5,290	6,521	28,135
Alaska	28,779	30,277	39,266	35,333	74,661
Lower 48 States	15,176	15,964	20,964	19,837	47,800

NOTE: Costs in 1985 dollars, based on 1985 cost factors.

Source: ERG estimates.

Table VI-9 Weighted Average Unit Costs of Produced Water Management for Model Projects under Alternative Waste Management Scenarios (Dollars per Barrel of Water)

Model project/ zone	Baseline	Intermediate		Subtitle C		Subtitle C-1	
		10%	70%	10%	70%	10%	70%
Appalachian	$0.52	$0.57	$0.94	$0.80	$2.51	$0.67	$1.57
Gulf	0.08	0.06	0.10	0.16	0.65	0.15	0.57
Midwest	0.14	0.14	0.14	0.22	0.65	0.15	0.20
Plains	0.16	0.16	0.16	0.24	0.74	0.20	0.47
Texas/Oklahoma	0.13	0.13	0.13	0.20	0.61	0.15	0.31
Northern Mountain	0.07	0.07	0.07	0.11	0.36	0.09	0.22
Southern Mountain	0.13	0.13	0.13	0.19	0.55	0.14	0.24
West Coast	0.04	0.04	0.04	0.08	0.34	0.07	0.26
Alaska	0.31	0.31	0.31	0.46	1.42	0.34	0.56
Lower 48 States	0.11	0.11	0.12	0.18	0.62	0.15	0.35

NOTE: Waste management costs applied to both oil and gas production wastes. Costs in 1985 dollars.

Source: ERG estimates.

Table VI-10 Impact of Waste Management Costs on Model Projects: Comparisons of After-Tax Internal Rate of Return [a]
(%)

Model project/ zone	Baseline	Alternative waste management scenarios					
		Intermediate		Subtitle C		Subtitle C-1	
		10%	70%	10%	70%	10%	70%
Appalachian	10.3%	10.2%	8.9%	8.9%	0.9%	9.2%	3.6%
Gulf-gas	22.9	22.8	22.5	22.5	20.7	22.6	20.7
Gulf-oil	36.4	36.2	34.5	33.2	15.6	33.5	17.9
Midwest	12.1	12.1	11.8	8.2	-19.4	10.9	5.1
Plains	9.0	9.0	8.6	6.9	-5.6	7.7	0.0
Texas/Oklahoma-gas	19.6	19.5	19.3	19.4	18.3	19.4	18.5
Texas/Oklahoma-oil	29.6	29.5	28.9.	27.4	14.6	28.4	22.1
Northern Mountain	19.6	19.5	19.0	18.2	10.1	18.6	13.1
Southern Mountain	9.2	9.2	9.0	8.3	3.3	8.7	6.3
West Coast	35.0	35.0	34.5	33.6	25.4	33.8	26.9
Alaska	10.9	10.9	10.9	10.8	10.6	10.9	10.8
Lower 48 States	28.9	28.8	28.0	26.6	13.0	27.6	19.7

NOTE: Both drilling and production wastes regulated.

[a]Internal rate of return defined as return after corporate taxes, to total invested capital including both equity and debt.

Source: ERG estimates.

Table VI-11 Impact of Waste Management Costs on Model Projects: Increase in Total Cost of Production[a] (Dollars per Barrel of Oil Produced)

Model project/ zone	Total baseline cost	Increase in cost under alternative waste management scenarios					
		Intermediate		Subtitle C		Subtitle C-1	
		10%	70%	10%	70%	10%	70%
Appalachian	$16.22	$ 0.05	$ 0.44	$ 0.45	$ 3.24	$ 0.33	$ 2.35
Gulf-gas	9.45	0.01	0.03	0.03	0.20	0.03	0.20
Gulf-oil	15.65	0.01	0.17	0.40	2.85	0.36	2.48
Midwest	19.45	0.01	0.07	1.11	8.31	0.34	2.12
Plains	18.46	0.02	0.09	0.51	3.69	0.33	2.46
Texas/Oklahoma-gas	7.61	0.01	0.02	0.02	0.11	0.02	0.09
Texas/Oklahoma-oil	14.86	0.01	0.07	0.40	1.24	0.20	2.74
Northern Mountain	15.51	0.02	0.12	0.36	2.56	0.23	1.65
Southern Mountain	18.05	0.01	0.08	0.29	2.01	0.16	0.99
West Coast	13.19	0.00	0.07	0.23	1.68	0.18	1.34
Alaska	15.02	0.00	0.00	0.01	0.10	0.00	0.03
Lower 48 States	14.11	0.01	0.11	0.40	2.88	0.20	1.55

[a] Total cost of production defined to include capital costs, operating costs, lease bonus costs, and pollution control costs, as well as transfer payments such as Federal income taxes, royalties, and State severance taxes.

Source: ERG estimates.

project after-tax internal rates of return decline under the waste management scenarios to the 13.0 to 28.8 percent range for the Lower 48 average.

The after-tax cost of producing hydrocarbons can also increase substantially. As Table VI-11 shows, these costs can increase by up to $2.98 per barrel of oil equivalent (BOE), a 20 percent increase over baseline costs. The impacts of these cost increases on a national level are described further below.

REGIONAL- AND NATIONAL-LEVEL COMPLIANCE COSTS OF THE WASTE MANAGEMENT SCENARIOS

The cost of waste management for the typical projects under each waste management scenario (see Tables VI-8 and VI-9) were used in conjunction with annual drilling (API 1986) and production levels (API 1987c) to estimate the regional- and national-level annual costs of the waste management scenarios. These costs, which include both drilling and production waste disposal costs, are presented in Table VI-12. National-level costs range from $49 million in the Intermediate 10% Scenario to more than $12.1 billion in the Subtitle C 70% Scenario.

The costs presented in Table VI-12 do not include the effects of closures. They are based on 1985 drilling and production levels, assuming that no activities are curtailed because of the requirements of the waste management scenarios. In reality, each of the waste management scenarios would result in both the early closure of existing projects and the cancellation of new projects. To the extent that the level of oil and gas activity declines, total aggregate compliance costs incurred under each waste management scenario will be lower, but there will be other costs to the national economy caused by lower levels of oil production. These effects are described more fully below.

Table VI-12 Annual Regional and National RCRA Compliance Cost of Alternative Waste Management Scenarios
(Millions of Dollars)

Model project/ zone	Waste management scenarios					
	Intermediate		Subtitle C		Subtitle C-1	
	10%	70%	10%	70%	10%	70%
Appalachian	$5	$43	$57	$403	$47	$328
Gulf	8	94	200	1,417	180	1,239
Midwest	1	6	120	870	31	185
Plains	2	17	126	907	77	576
Texas/Oklahoma	26	181	879	6,156	442	2,873
Northern Mountains	3	19	94	677	55	404
Southern Mountains	3	21	92	643	47	297
West Coast	1	36	126	936	97	736
Alaska	0	2	17	118	5	34
Lower 48 States	49	418	1,693	12,007	975	6,637
National Total	49	420	1,710	12,125	980	6,671

NOTE: Figures represent before-tax total annual increase in waste management cost over baseline costs at 1985 levels of drilling and production, without adjusting for decreases in industry activity caused by higher production costs at affected sites. Column totals may differ because of independent rounding. Base year for all costs is 1985.

CLOSURE ANALYSIS FOR EXISTING WELLS

The potential of the waste management scenarios to shut down existing producing wells was estimated using the model facility approach. The model facility simulations for existing projects, however, do not include the initial capital cost of leasing and drilling the production well. For the analysis of existing projects, it is assumed that these costs have already been incurred. The projects are simulated for their operating years. If operating revenues exceed operating costs, the projects remain in production.

Closures of existing wells are estimated by using a variable called the economic limit (i.e., a level of production below which the project cannot continue to operate profitably). Under the waste management scenarios, produced water disposal costs are higher and, therefore, the economic limit is higher. Some projects that have production levels that exceed the baseline economic limit would fall below the economic limit under the alternative waste management scenarios. Those projects not meeting this higher level of production can be predicted to close. This analysis was conducted only with respect to stripper wells. To the extent that certain high-volume, low-margin wells may also be affected, the analysis may understate short-term project closures.

The economic limit analysis requires information on the distribution of current production levels across wells. Because of the lack of data for most States, the economic limit analysis is presented here only for Texas and on a national level. The 1985 distribution of production by volume size class for Texas and for the Nation as a whole is shown in Table VI-13.

Table VI-14 displays the results of the economic limit analysis. Under baseline assumptions, the representative Lower 48 project requires 2.40 barrels per day to remain in operation. The economic limit for

Table VI-13 Distribution of Oil Production
Across Existing Projects, 1985

Region	Production Interval (BOPD) bbl/d	Number of Wells	Total Oil Production 1000 bb/d
National			
	0 - 1	112,000	71
	1 - 2	112,000	165
	2 - 3	78,000	206
	3 - 4	65,000	231
	4 - 5	20,000	92
	5 - 6	27,000	154
	6 - 7	21,000	142
	7 - 8	16,000	119
	8 - 9	15,000	129
	9 - 10	9,000	63
Total		475,000	1,371
Texas	<1	42,881	21
	1.0 - 1.5	15,018	19
	1.6 - 2.5	20,856	43
	2.6 - 3.5	14,018	43
	3.6 - 4.5	11,303	46
	4.6 - 5.5	9,665	49
	5.6 - 6.5	7,638	46
	6.6 - 7.5	6,201	44
	7.6 - 8.6	5,420	44
	9.6 - 1.05	4,441	45
Total			142,743
446			

Sources: :The Effect of Lower Oil Prices on Production From Proved U.S. Oil Reserves," Energy and Environmental Analysis, Inc., February 1987, taken from Figure 2-2. Indicators: A Monthly Data Review-April 1986, Railroad Commission of Teas, April 1986.

Table VI-14 Impact of Waste Management Cost on Existing Production

Region	Scenario	Economic limit (bbl/d)	Lower-range effects: Well closures: Number of wells	Lower-range effects: Well closures: Percent of wells	Lower-range effects: Lost production: 1000 bbl/d	Lower-range effects: Lost production: Percent of production	Upper-range effects: Well closures: Number of wells	Upper-range effects: Well closures: Percent of wells	Upper-range effects: Lost production: 1000s bbl/d	Upper-range effects: Lost production: Percent of production
Texas										
	Baseline[a]	2.30								
	Intermediate 10%	2.32	42	0.02	0.09	0.00	6,562	3.29	5.60	0.24
	Intermediate 70%	2.32	292	0.15	0.60	0.03	45,931	23.05	33.22	1.67
	Subtitle C 10%	3.89	2,260	1.13	6.92	0.30	8,780	4.41	12.00	0.53
	Subtitle C 70%	3.89	15,818	7.94	48.41	2.07	61,457	30.84	87.04	3.71
	Subtitle C-1 10%	2.73	740	0.37	1.84	0.08	7,259	3.64	7.36	0.31
	Subtitle C-1 70%	2.73	5,177	2.60	12.87	0.55	50,816	25.50	51.49	2.20
National:	Lower 48 States									
	Baseline[b]	2.40								
	Intermediate 10%	2.42	156	0.03	0.41	0.00	20,652	3.33	21.00	0.25
	Intermediate 70%	2.42	1,092	0.18	2.88	0.03	144,564	23.31	148.45	1.75
	Subtitle C 10%	4.20	11,580	1.87	37.32	0.44	32,076	5.17	58.00	0.68
	Subtitle C 70%	4.20	81,060	13.07	261.23	3.07	224,532	36.20	406.79	4.79
	Subtitle C-1 10%	3.01	4,745	0.77	13.00	0.15	25,241	4.07	33.00	0.39
	Subtitle C-1 70%	3.01	33,215	5.36	88.14	1.04	176,687	28.49	233.70	2.75

[a] Baseline production level is 2.3 million bbl/d; baseline well total is 199,000.
[b] Baseline production level is 8.6 million bbl/d; baseline well total is 620,000.

Source: ERG estimates.

affected operations rises to 3.01 to 4.20 barrels per day under the waste management scenarios. The increase in the economic limit results in closures of from 0.03 percent to 36.20 percent of all producing wells.

The "lower-range effects" in Table VI-14 assume that only affected wells (i.e., wells generating hazardous produced waters) producing at levels between the baseline economic limit and the economic limit under the waste management scenarios will be closed. The "upper-range effects" assume that all affected wells producing at levels below the economic limit under the waste management scenarios will be closed, and are adjusted to account for the change in oil prices from 1985 to 1986.

Under the lower-range effects case, production losses are estimated at between 0.00 and 3.07 percent of total production. Under the upper-range effects assumptions, production closures range from 0.25 to 4.79 percent of the total. These results are indicative of the immediate, short-term impact of the waste management scenarios caused by well closures.

The results of the Texas simulation mirror those of the national-level analysis. This would be expected, since nearly 30 percent of all stripper wells are in Texas, and the State is, therefore, reflected disproportionately in the national-level analysis. Under the lower-range effects assumptions, Texas production declines between 0.00 and 2.07 percent. Under the upper-range effects assumptions, Texas production declines between 0.24 and 3.71 percent.

THE INTERMEDIATE AND LONG-TERM EFFECTS OF THE WASTE MANAGEMENT SCENARIOS

Production Effects of Compliance Costs

The intermediate and long-term effects of the waste management scenarios will exceed the short-term effects for two principal reasons.

First, the increases in drilling waste management cost, which do not affect existing producers, can influence new project decisions. Second, the higher operating costs due to produced water disposal requirements may result in some project cancellations because of the expectation of reduced profitability during operating years. Although such projects might be expected to generate profits in their operating years (and therefore might be expected to operate if drilled), the reduced operating profits would not justify the initial investment.

The intermediate and long-term production effects were estimated using Department of Energy (DOE) production forecasting models. As described above, an economic simulation model was used to calculate the increase in the cost of resource extraction under each waste management scenario. These costs were used in conjunction with the DOE FOSSIL2 model (DOE 1985) and the DOE PROLOG model (DOE 1982) to generate estimates of intermediate and long-term production effects of the waste management scenarios.

For the FOSSIL2 model, an estimate of the increase in resource extraction costs for each waste management scenario, based on model project analysis, was provided as an input. Simulations were performed to measure the impact of this cost increase on the baseline level of production.

For the PROLOG model, no new simulations were performed. Instead, results of previous PROLOG modeling were used to calculate the elasticity of supply with respect to price in the PROLOG model. The model project simulation results were used to calculate an oil price decline that would have the same impact as the cost increase occurring under each alternative waste management scenario. These price increases were used in conjunction with an estimate of the price elasticity of supply from the PROLOG model to estimate an expected decline in production for each waste management scenario.

Table VI-15 shows the results of this analysis. The long-term impacts of the waste management scenarios range from levels that are below the detection limits of the modeling system to declines in production ranging up to 32 percent in the year 2000, based on the PROLOG analysis. For the FOSSIL2 simulations, production declines were estimated to range from "not detectable" to 18 percent in the year 2000 and from "not detectable" to 29 percent in the year 2010.

Additional Impacts of Compliance Costs

The decline in U.S. oil production brought about by the cost of the waste management scenarios would have wide-ranging effects on the U.S. economy. Domestic production declines would lead to increased oil imports, a deterioration in the U.S. balance of trade, a strengthening of OPEC's position in world markets, and an increase in world oil prices. Federal and State revenues from leasing and from production and income taxes would decline. Jobs would be lost in the oil and gas drilling, servicing, and other supporting industries; jobs would be created in the waste management industries (e.g., contractors who drill and complete Class I injection wells).

It is beyond the scope of this report to fully analyze all of these and other macroeconomic effects. To illustrate the magnitude of some of these effects, however, five categories of impacts were defined and quantified (oil imports, balance of trade, oil price, Federal leasing revenues, and State production taxes). These are presented in Table VI-16. Measurable effects are evident for all but the lowest cost (Intermediate 10% Scenario).

The impacts of the waste management scenarios on the U.S. economy were analyzed utilizing the DOE FOSSIL2/WOIL modeling system. Cost increases for U.S. oil producers create a slight decrease in the world oil supply curve (i.e., the amount of oil that would be brought to market at any oil price declines). The model simulates the impact of this shift on the world petroleum supply, demand, and price.

Table VI-15 Long-Term Impacts on Production of Cost Increases under Waste Management Scenarios

(%) Scenario	Estimated resource extraction cost increase (%)	Decline of domestic oil production in lower 48 States				
		Year 1990		Year 2000		Year 2010
		FOSSIL2	PROLOG	FOSSIL2	PROLOG	FOSSIL2
Intermediate 10%	0.16	No detectable change	No detectable change	No detectable change	No detectable change	No detectable change
Intermediate 70%	2.49	No detectable change	No detectable change	1.4%	No detectable change to 0.4%	1.6%
Subtitle C 10%	9.51	No detectable change	0.3% to 0.4%	4.2%	1.6% to 3.5%	6.3%
Subtitle C 70%	68.84	3.2%	6.9% to 7.8%	18.1%	19.1% to 32.4%	28.6%
Subtitle C-1 10%	4.73	No detectable change	No detectable change	1.4%	0.3% to 1.4%	3.2%
Subtitle C-1 70%	36.51	2.1%	3.7% to 4.3%	12.5%	10.7% to 18.5%	19.0%

Source: ERG estimates for extraction cost increase and for PROLOG impacts. Applied Energy Services of Arlington, Virginia, (Wood 1987) for FOSSIL2 results, based on specific runs of U.S. Department of Energy FOSSIL2 Model for alternative scenario cost increases. Department of Energy baseline crude oil price per barrel assumptions in FOSSIL2 were $20.24 in 1990, $33.44 in 2000, and $52.85 in 2010.

Table VI-16 Effect of Domestic Production Decline on Selected Economic Parameters in the Year 2000

Waste management scenario	Projected decline in lower 48 production (%)[a]	Increase in petroleum imports (millions of barrels per day)	Increase in U.S. balance of trade deficit ($ billions per year)	Increase in world oil price (dollars per barrel)[a]	Annual cost to consumers of the oil price increase ($ billions per year)	Decrease in Federal leasing revenues ($ millions per year)	Decrease in State tax revenues ($ millions per year)
Intermediate 10%	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Intermediate 70%	1.4%	N.D.	$0.2	$0.06	$0.4	$19.1	$71.0
Subtitle C 10%	4.2%	0.2	$3.2	$0.21	$1.2	$53.6	$208.9
Subtitle C 70%	18.1%	1.1	$17.5	$1.08	$6.4	$279.8	$903.2
Subtitle C-1 10%	1.4%	0.1	$1.6	$0.12	$0.7	$20.9	$60.7
Subtitle C-1 70%	12.5%	0.7	$11.3	$0.76	$4.5	$176.2	$616.1

N.D. - Not detectable using the FOSSIL2/WOIL modeling system.

[a] Revised baseline values for year 2000 in the FOSSIL2 modeling system include (1) lower 48 States crude oil production of 7.2 million barrels per day; (2) U.S. imports of 9.2 million barrels per day; and (3) world crude oil price of $33.44 per barrel.

Source: Results based on U.S. Department of Energy's FOSSIL2/WOIL energy modeling system, with special model runs for individual waste management scenario production costs effects conducted by Applied Energy Services of Arlington, Virginia (Wood 1987). ERG estimates based on FOSSIL2 results.

A new equilibrium shows the following effects:

- A lower level of domestic supply (previously depicted in Table VI-15);
- A higher world oil price (see Table VI-16);
- A decrease in U.S. oil consumption caused by the higher world oil price; and
- An increase in U.S. imports to partially substitute for the decline in domestic supply (also shown in Table VI-16).

The first numerical column in Table VI-16 shows the decline in U.S. production associated with each waste management scenario. These projections, derived from simulations of the FOSSIL2/WOIL modeling system, were previously shown in Table VI-15. The second column in Table VI-16 provides FOSSIL2/WOIL projections of the increase in petroleum imports necessary to replace the lost domestic supplies. The projections range from "not detectable" to 1.1 million barrels per day, equal to 1.4 to 18.1 percent of current imports of approximately 6.1 million barrels per day.

The third column in Table VI-16 shows the increase in the U.S. balance of trade deficit resulting from the increase in imports and the increase in the world oil price. The increase in the U.S. balance of trade deficit ranges from $0.2 to $17.5 billion under the waste management scenarios. The projected increase in petroleum imports under the most restrictive regulatory scenarios could be a matter for some concern in terms of U.S. energy security perspectives, making the country somewhat more vulnerable to import disruptions and/or world oil price fluctuations. In the maximum case estimated (Subtitle C 70% Scenario), import dependence would increase from 56 percent of U.S. crude oil requirements in the base case to 64 percent in the year 2000.

The fourth column shows the crude petroleum price increase projected under each of the waste management scenarios by the FOSSIL2/WOIL modeling system. This increase ranges from $0.06 to $1.08 per barrel of oil (a 0.2 to 3 percent increase). This increase in oil price translates into an increase in costs to the consumer of $0.4 to $6.4 billion in the year 2000 (column five). These estimates are derived by multiplying FOSSIL2-projected U.S. crude oil consumption in the year 2000 by the projected price increase. The estimates assume that the price increase is fully passed through to the consumer with no additional downstream markups.

Federal leasing revenues will also decline under the waste management scenarios. These revenues consist of lease bonus payments (i.e., initial payments for the right to explore Federal lands) and royalties (i.e., payments to the Federal government based on the value of production on Federal lands). Both of these revenue sources will decline because of the production declines associated with the waste management scenarios. If the revenue sources are combined, there will be a reduction of $19 to $280 million in Federal revenues in the year 2000.

State governments generally charge a tax on crude oil production in the form of severance taxes, set as a percentage of the selling price. On a national basis, the tax rate currently averages approximately 6.7 percent. Applying this tax rate, the seventh column in Table VI-16 shows the projected decline in State tax revenues resulting from the waste management scenarios. These estimates range from about $60 million to $900 million per year.

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CHAPTER VII

CURRENT REGULATORY PROGRAMS

INTRODUCTION

A variety of programs exist at the State and Federal levels to control the environmental impacts of waste management related to the oil and gas industry. This chapter provides a brief overview of the requirements of these programs. It also presents summary statistics on the implementation of these programs, contrasting the numbers of wells and other operations regulated by these programs with resources available to implement regulatory requirements.

State programs have been in effect for many years, and many have evolved significantly over the last decade. The material presented here provides only a general introduction to these complex programs and does not attempt to cover the details of State statutes and current State implementation policy. Additional material on State regulatory programs can be found in Appendix A. Federal programs are administered both by the Environmental Protection Agency and by the Bureau of Land Management within the U.S. Department of the Interior.

STATE PROGRAMS

The tables on the following pages compare the principal functional requirements of the regulatory control programs in the principal oil- and gas-producing States that have been the focus of most of the analysis of this study. These States are Alaska, Arkansas, California, Colorado, Kansas, Louisiana, Michigan, New Mexico, Ohio, Oklahoma, Texas, West Virginia, and Wyoming.

Table VII-1 covers requirements for reserve pit design, construction, and operation; Table VII-2 covers reserve pit closure and waste removal. Table VII-3 presents requirements for produced water pit design and construction, while Table VII-4 compares requirements for the produced water surface discharge limits. Table VII-5 deals with produced water injection well construction; these requirements fall under the general Federal Underground Injection Control program, which is discussed separately below under Federal programs. Finally, Table VII-6 discusses requirements for well abandonment and plugging.

FEDERAL PROGRAMS--EPA

Federal programs discussed in this section include the Underground Injection Control (UIC) program and the Effluent Limitations Guidelines program administered by the EPA.

Underground Injection Control

The Underground Injection Control (UIC) program was established under Part C of the Safe Drinking Water Act (SDWA) to protect underground sources of drinking water (USDWs) from endangerment by subsurface emplacement of fluids through wells. Part C of the SDWA requires EPA to:

1. Identify the States for which UIC programs may be necessary--EPA listed all States and jurisdictions;
2. Promulgate regulations establishing minimum requirements for State programs which:
   - prohibit underground injection that has not been authorized by permit or by rule;
   - require applicants for permits to demonstrate that underground injection will not endanger USDWs;
   - include inspection, monitoring, record-keeping, and reporting requirements.

These minimum requirements are contained in 40 CFR Parts 144 and 146, and were promulgated in June 1980.

3. Prescribe by regulation a program applicable to the States, in cases where States cannot or will not assume primary enforcement responsibility. These direct implementation (DI) programs were codified in 40 CFR Part 147.

The regulations promulgated in 1980 set minimum requirements for 5 classes of wells including Class II wells--wells associated with oil and gas production and hydrocarbon storage. In December 1980, Congress amended the SDWA to allow States to demonstrate the effectiveness of their in-place regulatory programs for Class II wells, in lieu of demonstrating that they met the minimum requirements specified in the UIC regulations. In order to be deemed effective, State Class II programs had to meet the same statutory requirements as the other classes of wells, including prohibition of unauthorized injection and protection of underground sources of drinking water. (§1425 SDWA). Because of the large number of Class II wells, the regulations allow for authorization by rule for existing enhanced recovery wells (i.e., wells that were injecting at the time a State program was approved or prescribed by EPA). In DI States, these wells are subject to requirements specified in Part 147 for authorization by rule, which are very similar to requirements applicable to permitted wells, with some relief available from casing and cementing requirements as long as the wells do not endanger USDWs. In reviewing State programs where the intent was to "grandfather" existing wells as long as they met existing requirements, EPA satisfied itself that these requirements were sufficient to protect USDWs. In addition, all States adopted the minimum requirements of §146.08 for demonstrating mechanical integrity of the wells (ensuring that the well was not leaking or allowing fluid movement in the borehole), at least every 5 years. This requirement was deemed by EPA to be absolutely necessary in order to prevent endangerment of USDWs. In addition, EPA and the States have been conducting file reviews of all wells whether grandfathered or subject to new authorization-by-rule requirements. File reviews are assessments of the technical issues that would normally be part of a permit decision, including mechanical integrity testing, construction, casing and cementing, operational history, and monitoring records. The intent of the file review is to ensure that injection wells not subject to permitting are technically adequate and will not endanger underground sources of drinking water.

Because of §1425 and the mandate applicable to Federal programs not to interfere with or impede underground injection related to oil and gas production, to avoid unnecessary disruption of State programs and to consider varying geologic, hydrologic, and historical conditions in different States, EPA has accepted more variability in this program than in many of its other regulatory programs. Now that the program has been in place for several years, the Agency is starting to look at the adequacy of the current requirements and may eventually require more specificity and less variation among States.

Effluent Limitations Guidelines

On October 30, 1976, the Interim Final BPT Effluent Limitations Guidelines for the Onshore Segment of the Oil and Gas Extraction Point Source Category were promulgated as 41 FR (44942). The rulemaking also proposed Best Available Technology Economically Achievable (BAT) and New Source Performance Standards.

On April 13, 1979, BPT Effluent Limitations Guidelines were promulgated for the Onshore Subcategory, Coastal Subcategory, and Agricultural and Wildlife Water Use Subcategory of the Oil and Gas Extraction Industry (44 FR 22069). Effluent limitations were reserved for the Stripper Subcategory because of insufficient technical data.

The 1979 BPT regulation established a zero discharge limitation for all wastes under the Onshore Subcategory. Zero discharge Agricultural and Wildlife Subcategory limitations were established, except for produced water, which has a 35-mg/L oil and grease limitation.

The American Petroleum Institute (API) challenged the 1979 regulation (including the BPT regulations for the Offshore Subcategory) (661 F.2D.340(1981)). The court remanded EPA's decision transferring 1,700 wells from the Coastal to the Onshore Subcategory (47 FR 31554). The court also directed EPA to consider special discharge limits for gas wells.

Summary of Major Regulatory Activity Related to Onshore Oil and Gas

October 13, 1976 - Interim Final BPT Effluent Limitations Guidelines and Proposed (and Reserved) BAT Effluent Limitations Guidelines and New Source Performance Standards for the Onshore Segment of the Oil and Gas Extraction Point Source Category

April 13, 1979 - Final Rules

- BPT Final Rules for the Onshore, Coastal, and Wildlife and Agricultural Water Use Subcategories
- Stripper Oil Subcategory reserved
- BAT and NSPS never promulgated

July 21, 1982 - Response to American Petroleum Institute vs. EPA Court Decision

- Recategorization of 1,700 "onshore" wells to Coastal Subcategory
- Suspension of regulations for Santa Maria Basin, California
- Planned reexamination of marginal gas wells for separate regulations

Onshore Segment Subcategories

Onshore

- BPT Limitation

  -- Zero discharge

- Defined: NO discharge of wastewater pollutants into navigable waters from ANY source associated with production, field exploration, drilling, well completion, or well treatment (i.e., produced water, drilling muds, drill cuttings, and produced sand).

Stripper (Oil Wells)[1]

- Category reserved

- Defined: TEN barrels per well per calendar day or less of crude oil.

1 This subcategory does not include marginal gas wells.

<u>Coastal</u>

- BPT Limitations

  -- No discharge of free oil (no sheen)

  -- Oil and grease: 72 mg/L (daily)
48 mg/L (average monthly)
(produced waters)

- Defined: Any body of water landward of the territorial seas or any wetlands adjacent to such waters.

<u>Wildlife and Agriculture Use</u>

- BPT Limitations

  -- Oil and Grease: 35 mg/L (produced waters)
-- Zero Discharge: <u>ANY</u> waste pollutants

- Defined: That produced water is of good enough quality to be used for wildlife or livestock watering or other agricultural uses west of the 98th meridian.

FEDERAL PROGRAMS--BUREAU OF LAND MANAGEMENT

Federal programs under the Bureau of Land Management (BLM) within the U.S. Department of the Interior are discussed in this section.

Introduction

Exploration, development, drilling, and production of onshore oil and gas on Federal and Indian lands are regulated separately from non-Federal lands. This separation of authority is significant for western States where oil and gas activity on Federal and Indian lands is a large proportion of statewide activity.

Regulatory Agencies

The U.S. Department of the Interior exercises authority under 43 CFR 3160 for regulation of onshore oil and gas practices on Federal and Indian lands. The Department of the Interior administers its regulatory program through BLM offices in the producing States. These offices generally have procedures in place for coordination with State agencies on regulatory requirements. Where written agreements are not in place, BLM usually works cooperatively with the respective State agencies. Generally, where State requirements are more stringent than those of BLM, operators must comply with the State requirements. Where State requirements are less stringent, operators must meet the BLM requirements.

The Bureau works closely with the U.S. Forest Service for surface stipulations in Federal forests or Federal grasslands. This cooperative arrangement is specifically provided for in the Federal regulations.

Rules and Regulations

BLM has authority over oil and gas activities on Federal lands. The authority includes leasing, bonding, royalty arrangements, construction and well spacing regulations, waste handling, most waste disposal, site reclamation, and site maintenance.

Historically, BLM has controlled oil and gas activities through Notices to Lessees (NTLs) and through the issuance of permits. The Bureau is working to revise all notices into Oil and Gas Orders, which will be Federally promulgated. To date, Oil and Gas Order No. 1 has been issued.

While the regulations, NTLs, and orders provide the general basis for regulation of oil and gas activities on Federal and Indian lands, there are variations in actual application of some of the requirements among BLM districts. In many cases, the variations are in response to specific geographical or geological characteristics of particular areas.

For example, in middle and southern Florida, the water table is near the surface. As a result, BLM requires the use of tanks instead of mud pits for oil and gas drilling activities on Federal lands in this area. In southeast New Mexico, there is simultaneous development of potash resources and oil and gas resources, and drilling and development requirements are imposed to accommodate the joint development activities. In general, more stringent controls of wastes and of disposal activities are required for oil and gas activities that could affect ground-water aquifers used for drinking water.

Drilling

Before beginning to drill on Federal land, operators must receive a permit to drill from BLM. The permit application must include a narrative description of waste handling and waste disposal methods planned for the well. Any plans to line the reserve pit must be detailed.

The lease is required to be covered by a bond prior to beginning drilling of the well. But the bonds may be for multiple wells, on a lease basis, statewide basis, or nationwide basis. The current bond requirement for wells on a single lease is $10,000. Statewide bonds are $25,000, but bonds must be provided separately for wells on public land and wells on Federally acquired land. The requirement for a nationwide bond is $150,000.

BLM considers reserve pits, and some other types of pits, as temporary. Except in special circumstances, reserve pits do not have to be lined. NTL-2B contains the following provisions for "Temporary Use of Surface Pits":

> Unlined surface pits may be used for handling or storage of fluids used in drilling, redrilling, reworking, deepening, or plugging of a well provided that such facilities are promptly and properly emptied and restored upon completion of the operations. Mud or other fluids contained in such pits shall not be disposed of by cutting the pit walls without the prior authorization of the authorized officer.
>
> Unlined pits may be retained as emergency pits, if approved by the authorized officer, when a well goes into production.
>
> Landspreading of drilling and reworking wastes by breaching pit walls is allowed when approved by the authorized officer.

Production

Produced waters may be disposed of by underground injection, by disposal into lined pits, or "by other acceptable methods." An application to dispose of produced water must specify the proposed method and provide information that will justify the method selected. One application may be submitted for the use of one disposal method for produced water from wells and leases located in a single field, where the water is produced from the same formation or is of similar quality.

Disposal in Pits: A number of general requirements apply to disposal into permanent surface disposal pits, whether lined or unlined. The pits must:

1. Have adequate storage capacity to safely contain all produced water even in those months when evaporation rates are at a minimum;

2. Be constructed, maintained, and operated to prevent unauthorized surface discharges of water; unless surface discharge is authorized, no siphon, except between pits, will be permitted;

3. Be fenced to prevent livestock or wildlife entry to the pit, when required by an authorized officer;

4. Be kept reasonably free from surface accumulations of liquid hydrocarbons by use of approved skimmer pits, settling tanks, or other suitable equipment; and

5. Be located away from the established drainage patterns in the area and be constructed so as to prevent the entrance of surface water.

Approval of disposal of produced water into unlined pits will be considered only if one or more of the following applies:

- The water is of equal or better quality than potentially affected ground water or surface waters, or contains less than 5,000 ppm total dissolved solids (annual average) and no objectionable levels of other toxic constituents;

- A substantial proportion of the produced water is being used for beneficial purposes, such as irrigation or livestock or wildlife watering;
- The volume of water disposed of does not exceed a monthly average of 5 barrels/day/facility; and
- A National Pollutant Discharge Elimination System (NPDES) permit has been granted for the specific disposal method.

Operators using unlined pits are required to provide information regarding the sources and quantities of produced water, topographic map, evaporation rates, estimated soil percolation rates, and "depth and extent of all usable water aquifers in the area."

Unlined pits may be used for temporary containment of fluids in emergency circumstances as well as for disposal of produced water. The pit must be emptied and the fluids appropriately disposed of within 48 hours after the emergency.

Where disposal in lined pits is allowed, the linings of the pits must be impervious and must not deteriorate in the presence of hydrocarbons, acids, or alkalis. Leak detection is required for all lined produced water disposal pits. The recommended detection system is an "underlying gravel-filled sump and lateral system." Other systems and methods may be considered acceptable upon application and evaluation. The authorized officer must be given the opportunity to examine the leak detection system before installation of the pit liner.

When applying for approval of surface disposal into a lined pit, the operator must provide information including the lining material and leak detection method for the pit, the pit's size and location, its net evaporation rate, the method for disposal of precipitated solids, and an analysis of the produced water. The water analysis must include concentrations of chlorides, sulfates, and other (unspecified) constituents that could be toxic to animal, plant, or aquatic life.

Injection: Produced waters may be disposed of into the subsurface, either for enhanced recovery of hydrocarbon resources or for disposal. Since the establishment of EPA's underground injection control program for Class II injection wells, BLM no longer directly regulates the use of injection wells on Federal or Indian lands. Instead, it defers to either EPA or the State, where the State has received primacy for its program, for all issues related to ground-water or drinking water protection. Operators must obtain their underground injection permits from either EPA or the State.

BLM still retains responsibility for making determinations on injection wells with respect to lease status, protection of potential oil and gas production zones, and the adequacy of pressure-control and other safety systems. It also requires monthly reports on volumes of water injected.

Plugging/Abandonment

When a well is a dry hole, plugging must take place before removal of the drilling equipment. The mud pits may be allowed to dry before abandonment of the site. No abandonment procedures may be started without the approval of an authorized BLM representative. Final approval of abandonment requires the satisfactory completion of all surface reclamation work called for in the approved drilling permit.

Within 90 days after a producing well ceases production, the operator may request approval to temporarily abandon the well. Thereafter, reapproval for continuing status as temporarily abandoned may be required every 1 or 2 years. Exact requirements depend on the District Office and on such factors as whether there are other producing wells on the lease. The well may simply be defined as shut-in if equipment is left in place.

Plugging requirements for wells are determined by the BLM District Office. Typically, these will include such requirements as a 100-foot cement plug over the shoe of the surface casing (half above, half below), a 20- to 50-foot plug at the top of the hole, and plugs (usually 100 feet across) above and below all hydrocarbon or freshwater zones.

IMPLEMENTATION OF STATE AND FEDERAL PROGRAMS

Table VII-7 presents preliminary summary statistics on the resources of State oil and gas regulatory programs for the 13 States for which State regulatory programs have been summarized in Tables VII-1 through VII-6. Topics covered include rates of gas and oil production, the number of gas and oil wells, the number of injection wells, the number of new wells, the responsible State agency involved, and the number of total field staff in enforcement positions.

Table VII-8 presents similar statistics covering activities of the Bureau of Land Management. Since offices in one State often have responsibilities for other States, each office is listed separately along with the related States with which it is involved. Statistics presented include the number of oil and gas producing leases, the number of nonproducing oil and gas leases, and the number of enforcement personnel available to oversee producing leases.

Table VII- 1 Reserve Pit Design, Construction and Operation

State	General statement of objective/purpose	Liners	Overtopping	Commingling provision	Permitting/ oversight
Alaska	The pits must be rendered impervious.	Whether reserve pit requires lining (and what kind of lining) depends on proximity to surface water and populations, whether the pit is above permafrost, and what kind of pit management strategy is used; visual monitoring required, and ground water monitoring usually required.	Fluid mgmt provision entails use of dewatering practices to keep to a minimum the hydrostatic head in a containment structure to reduce the potential for seepage and to prevent overflow during spring thaw.	Reserve pit "drilling wastes" defined as including "drilling muds, cuttings, hydrocarbons, brine, acid, sand, and emulsions or mixtures of fluids produced from and unique to the operation or maintenance of a well."	Individual permit for active and new pits.
Arkansas (revisions due in '88)	Oil & Gas Commission (OGC); no specific regulations governing construction or management of reserve pits. Dept. of Pollution Control & Ecology (DPCE) incorporates specific requirements in letters of authorizataion serving as informal permits, but regulatory basis and legal enforceability not supported by OGC.	OGC: No regulatory requirement. DPCE: 20-mil synthetic or 18-24 inch thick liner (per authorization letter).	1-ft freeboard (DPCE: 2-ft per authorization letter).	DPCE only: no high TDS completion fluids (per authorization letter).	OGC: No separate permit for reserve pit. DPCE: Terms of permitting for reserve pits incorporated in letter of authorization.
California	No degradation of ground-water quality; if waste is hazardous, detailed standards apply to the pits as "surface	Liners may or may not be required, depending on location and local regulations; in limited cases where fluids		Use of nonapproved additives and fluids renders the waste subject to regulation as a hazardous waste.	Regional Water Quality Control Boards (RWQCBs) have authority to permit, oversee management.

Table VII-1 (continued)

State	General statement of objective/purpose	Liners	Overtopping	Commingling provision	Permitting/oversight
California (continued)	impoundments"; if nonhazardous, the waste "shall be disposed of in such a manner as not to cause damage to life, health, property, fresh water aquifers or surface waters, or natural resources, or be a menace to public safety."	contain hazardous materials, double liners required			
Colorado	Prevent pollution (broadly defined) of State waters; prevent exceeding of stream standards.	Liners and leak detection systems generally reqd for pits with a capacity greater than 100 bbl/d and a TDS content greater than 5,000 ppm; liners also reqd in designated areas overlying domestic water supplies.		No prohibition on commingling of drilling muds and initial water production, but disposal of greater than 5 bbl/d produced water renders the reserve pit subject to regulations for pits receiving produced water; no wells drilled with oil-based muds.	Individual permit if pit receives more than 5 barrels fluid per day.
Kansas	Specific delineation of areas requiring liners (proposed)	No general requirement; liners may be required in geologically or hydrologically sensitive areas (e.g., over sandy soils); Commission may require observation trenches, holes, or monitoring wells.	1-ft freeboard (proposed regs).		General permits for pits operating for less than 1 year (extensions granted); individual permits granted unless denied within 10 days of application (proposed regs).

Table VII-1 (continued)

State	General statement of objective/purpose	Liners	Overtopping	Commingling provision	Permitting/ oversight
Louisiana	Prevent contamination of aquifers, including USDWs, and protect surface water.	Liners not required for onsite reserve pits; liners (10^{-7} cm/sec) reqd for offsite commercial facilities.	2-ft freeboard, protection of surface water by levees, walls, and drainage ditches.	No produced water or waste oil at onsite facilities	More stringent reqts (including financial respons.) for commercial facilities.
Michigan		Liners required when drilling with salt water-based drilling fluids; or when drilling through salt or brine-containing formations; in other areas, exceptions may be granted, but rarely are requested; liners must be 20 mil virgin PVC or its equivalent.		No salt cuttings as solids, oil, refuse, completion or test fluids.	Individual permit bond, and environmental assessment reqd.
New Mexico	Prevent contamination of surface and subsurface water.	Liners not required for onsite reserve pits; in the Northwest, liners may be required for commercial facilities.			Permits are reqd for centralized facilities with some exceptions.
Ohio	Prevent escape of produced water; prevent contamination of land, surface water, and ground water.	No requirement for liners, except where required on a site-specific basis in hydrogeologically sensitive areas.			

Table VII-1 (continued)

States	General statement of objective/purpose	Liners	Overtopping	Commingling provision	Permitting/ oversight
Oklahoma	Prevent pollution of surface and subsurface water, commercial pits must be sealed with an impervious material.	No liner requirement for reserve pits for wells using freshwater drilling muds, 30-mil liners (or metal tanks) reqd for pits containing "deleterious fluids other than freshwater drilling muds." 12-inch, 10^{-7} cm/sec soil liner for commercial pits; commercial pits must be at least 25 feet above highest aquifer, site-specific reqt for coml pits containing deleterious fluids.	18-inch freeboard and run-on controls; 36 inches for commercial pits.	More stringent reqts (i.e., liners) for fluids other than water-based muds provide an incentive to manage these wastes separately.	Permit not reqd for on-site pits; notification reqd for emergency and burn pits.
Texas	May not cause or allow pollution of surface or subsurface water.	Liners not required.		Use of reserve pits and mud circulation pits is restricted to drilling fluids, drill cuttings, sands, silts, wash water, drill stem test fluids, and blowout preventer test fluids.	Reserve pits and mud circulation pits are authorized by rule without permits; individual permit reqd for coml facilities, drilling fluid storage pits (other than mud circulation pits), and drilling fluid disposal pits (other than reserve pits).

Table VII-1 (continued)

States	General statement of objective/purpose	Liners	Overtopping	Commingling provision	Permitting/ oversight
W. Virginia	Prevent seepage, leakage, or overflow and maintain pit integrity.	Liners not reqd, except where soil is not suitable to prevent seepage or leakage.	Adequate freeboard	No produced water, unused fracturing fluid or acid, compressor oil, refuse, diesel, kerosene, halogenated phenol, etc.	General permit, offsite discharge of fluids requires an individual permit.
Wyoming	Prevent pollution of streams and underground water and unreasonable damage to the land.	Liners not reqd except where the potential for communication between the pit contents and surface water or shallow ground water is high.		No chemicals that reduce the pit's fluid seal.	Individual permit reqd except for workover and completion pits containing oil and/or water; more stringent design reqts for commercial pits.

Table VII-2 Reserve Pit Closure/Waste Removal

State	Deadline/ general standard	Land disposal/ application	Road application	Surface water discharge	Annular injection
Alaska	Must be operated with a fluid management plan and must be closed within 1 year after final disposal of drilling wastes in pit; or must be designed for 2 years' disposal and closed in that time period; numerous performance reqts added.	General permit for discharge of fluids to tundra; prior written approval reqd; specs and effluent monitoring for metals and conventional pollutants; only pits eligible are those that have received no drilling wastes since previous summer (last freeze-thaw cycle), to allow precipitation of contaminants.	Individual permit; compliance point is edge of the road for same specs as for land application (except pH); no requirement for freeze-thaw cycle.	See land application; specs same as AK WQS (except TDS) pending study to determine effect on wildlife.	General permit for N. Slope; prior written approval reqd; discharge must occur below the permafrost into a zone containing greater than 3,000 ppm TDS.
Arkansas (revisions due in '88)	OGC: No specific regulatory requirements. DPCE: within 60 days of rig's removal, reclaim to grade and reseed; fluids must be consigned to state-permitted disposal service (per authorization letter).	DPCE only: waste analysis and landowner's consent reqd for land application (per authorization letter).		Prohibited.	DPCE: prior approval reqd (per authorization letter).
California	When drilling operations cease, remove either (1) all wastes or (2) all free liquids and hazardous residuals.	Offsite disposal reqts depend on whether waste is "hazardous" (double liners), "designated" (single liner) or nonhazardous.		Permit reqd from RWQCB; disposal may not cause damage to surface water.	
Colorado	For dry and abandoned wells, within 6 months of a well's closure, decant the fluids, backfill and reclaim.	Dewatered sediment may be tilled into the ground.		Permits for discharge may be issued if effluent meets stream's classification standard.	

Table VII-2 (continued)

State	Deadline/ general standard	Land disposal/ application	Road application	Surface water discharge	Annular injection
Kansas	As soon as practical, evaporate or dewater and backfill; 365 days, or sooner if specifically required by Commission (proposed).	Landfarming is prohibited; in-situ disposal may be prohibited in sensitive areas.	If approved by Kansas Department of Health and Environment.		Prohibited.
Louisiana	Within 6 months of completion of drilling or workover activities, fluids must be analyzed for pH, O&G, metals and salinity, and then removed; exemption for wells less than 5,000 ft deep if native mud used.	Onsite land treatment or trenching of fluids and land treatment, burial or solidification of nonfluids allowed provided specs are met (including pH, electrical conductivity, and certain metals).		Permits issued for discharge of wastewater from treated drilling site reserve pits, so long as limitations for oil and grease, TSS, metals, chlorides, pH are met. Dilution allowed to meet chloride limits.	Surface casing must be at least 200 ft below the lowest USDW.
Michigan	At closure, all free liquids must be removed and the residue encapsulated onsite or disposed of offsite.	In-situ encapsulation requires a 10-mil PVC cap 4 ft below grade; offsite disposal must be in a lined landfill with leachate collection and ground-water monitoring	Prohibited.	Prohibited.	Well must have production casing and injected fluid must be isolated below freshwater horizons; exception granted if, among other things, pressure gradient is less than 0.7 psi.
New Mexico		Pits are evaporated and residue generally buried onsite.		Prohibited.	

State	Deadline/ general standard	Land disposal/ application	Road application	Surface water discharge	Annular injection
Ohio	Within 5 months of the commencement of drilling, backfill and remove concrete bases and drilling equipment, within 9 months, grade and revegetate area not reqd for production.	Drilling fluids may be disposed of by land application; pit solids may be buried onsite, except where history of ground-water problems		Permit reqd.	Standard well treatment fluids can be injected; same reqts as for annular produced water disposal; permit generally reqd
Oklahoma	Within 12 months of drilling operation's cessation, dewater and leave; 6-month extension for good cause; only 60 days allowed for circulating and fracture pits.	Landfarming of water-based muds is allowed; permit reqd; siting and rate application reqts, waste analysis, revegetation within 120 days		Prohibited.	Onsite injection allowed, approval reqd; surface casing must be set at least 200 ft below treatable water; limits on pressure so that vertical fractures will not extend to base of treatable water.
Texas	Within 30 days to 1 year from when drilling ceases (depending on the fluid's Cl content) dewater, backfill, and compact.	Landfarming prohibited for water-based drilling fluids having greater than 3,000 mg/L Cl and oil-based wastes; onsite burial prohibited for oil-based drilling fluids (but burial of solids obtained while using oil-based drilling fluid allowed).		Minor permit required for discharge of fluid fraction from treated reserve pits; prior notif. and 24-hour bioassay test reqd; discharge may not violate TX WQS or haz. metals limits; specs include O&G (15 mg/L), Cl (1,000 mg/L coastal, 500 mg/L in-land); TSS (50 mg/L), COD (200 mg/L), TDS (3000 mg/L)	One-time annular injection allowed; "minor permit" required; limits on surface injection pressure; casing set such that usable quality water protected to depth recommended by TWC.

State	Deadline/ general standard	Land disposal/ application	Road application	Surface water discharge	Annular injection
W. Virginia	Within 6 months from when drilling ceases.	Cuttings may be buried onsite; after physical treatment, fluids meeting specs can be applied to the land; specs include oil (no visible sheen on land) and Cl (25,000 mg/L), monitoring reqd for other parameters.			
Wyoming	Within 1 year of use, remove liquids and reclaim pit; reclamation bond released after pit closure inspected and approved.	Permit reqd for land application; discharge must meet water quality limits, including O&G (2,000 or 20,000 lb/acre, depending on whether soil incorporated), Cl (1,500 mg/L).	Permit reqd for road application; location and application reqts imposed through DEQ memorandum.	Prohibited, except where DEQ determines discharge will not cause sig. envir damage or contaminate public water supplies; application must include complete analysis, volume, location, and name of receiving stream.	One-time injection allowed under some conditions as in UIC permit.

Table VII-3 Produced Water Pit Design and Construction

State	General statement of objective/purpose	Liners	Exemptions	Permitting/oversight
Alaska	Produced water is a "drilling waste" and is subject to the same reqts as in Table VII-1.			
Arkansas (revisions due in '88)	No discharge into any water of the State (including ground water).	Pits must be lined or underlaid by tight soil; pits prohibited over porous soil; (DPCE authorization letter requires tanks).		Individual permit; application reqd within 30 days of producing waste.
California	Nondegradation of State waters; pits not permitted in natural drainage channels or where they may be in communication with freshwater-bearing aquifers.	Liners reqd where necessary to comply with the State's nondegradation policy; specific standards for construction/operation may be established by RWQCBs.		Subject to permitting authority of Regional WQCB.
Colorado	Prevent pollution (broadly defined) of State waters; prevent exceeding of stream standards.	Same as for reserve pits (for pits receiving more than 5 bbl/d 90% of the pits are lined; 2/3 clay, 1/3 synthetic)	Exemptions from liner requirement for pits overlying impermeable materials or receiving water with less than 5,000 ppm TDS.	Individual permit.
Kansas	Consideration of protection of soil and water resources from pollution.	Strict liner and seal requirements in conjunction with hydrogeologic investigation.		No permits issued for unlined pits.
Louisiana		All pits must be lined such that the hydraulic conductivity is less than 10^{-7} cm/sec.	Pits in certain coastal areas, provided they are part of a treatment train for oil and grease removal.	

State	General statement of objective/purpose	Liners	Exemptions	Permitting/oversight
Michigan	Brine cannot be run to earthen reservoirs or ponds.			
New Mexico		In the southeast, 30-mil liners with leak detection are reqd; in the northwest, liners are reqd over specified vulnerable aquifers.	Small-volume pits and pits in specified areas that are already saline and in areas without fresh water.	If liner required, individual permit after hearing.
Ohio	Pits must be liquid tight; waste cannot be stored for more than 180 days; pits may not be used for ultimate disposal.			Produced water disposal plan must be submitted.
Oklahoma	Pits must be sealed with an impervious material; in addition, offsite pits must contain fluids with less than 3,500 ppm Cl.	12-inch, 10^{-7} cm/sec soil liner for coml pits; site-specific liner reqt if coml pit contains deleterious fluids		Individual permits required.
Texas	Permit for unlined pit denied unless operator conclusively shows pit will not pollute agricultural land, surface or subsurface water; emergency pits generally exempted.	Generally, all pits other than emergency pits require liners unless (1) there is no surface or subsurface water in the area, or (2) the pit is underlaid by a naturally occurring impervious barrier; liners required for emergency pits in sensitive areas.		Individual permit.
W. Virginia	Same as for reserve pits.	Same as for reserve pits.		Same as for reserve pits.
Wyoming		Liners not reqd except where the potential for communication between the pit contents and surface water or shallow ground water is high.		Individual permit reqd if pit receives more than 5 bbl/day produced water; area-wide permits also granted; individual permits and more stringent terms for commercial pits.

Table VII-4 Produced Water Surface Discharge Limits

State	Onshore	Coastal/tidal	Beneficial use	Permitting/oversight
Alaska				Produced water is subject to the discharge reqts for reserve pit fluids in Table VII-1.
Arkansas	Prohibited.	Not applicable.		
California	In some cases, produced waters ultimately disposed of in sumps are allowed to first be discharged into canals or ephemeral streams that carry the salt water to the sumps.	Policy for enclosed bays and estuaries prohibits discharge of materials of petroleum origin in sufficient quantities to be visible or in violation of waste discharge reqts; Ocean Plan sets limits for O&G, arsenic, total chromium, etc.	Discharge allowed to canals, ditches, and ephemeral streams before reuse; specs issued by one RWQCB include O&G (35 mg/L) and Cl (200 mg/L).	Permit reqd from RWQCB for beneficial use.
Colorado	Discharge must not cause pollution (broadly defined) of any waters of the state; must not cause exceeding of stream standards.	N/A	Specs for wildlife and agricultural use include O&G (10 mg/L) and TDS (5,000 mg/L, 30-day average).	Permit reqd from Water Quality Control Division of Department of Health.
Kansas	Prohibited.	N/A		Road application requires approval by Dept. of Health and Environment.
Louisiana	Discharges allowed into lower distributaries of Mississippi and Atchafalaya Rivers; discharges into waters of the State require a permit after 11/20/86; facility deemed in compliance except where an investigation or a complaint has been filed.	Discharge allowed if treated to remove residual O&G.		Individual permits for surface discharges required after 11/20/86.

Table VII-4 (continued)

State	Onshore	Coastal/tidal	Beneficial use	Permitting/oversight
Michigan	Prohibited.	Prohibited.	Specs for dust control, 3-yr study to determine if practice should be continued.	
New Mexico	Prohibited except in emergencies or for construction, application reqd.	N/A	Use as drinking water for cattle and in construction, no contaminant levels specified.	State approval for cattle watering and construction reqd
Ohio	Discharge must not cause pollution of any waters of the State.	N/A	Reqts for road spreading include a 12-ft buffer zone to prevent damage to water bodies.	Road or land spreading must be authorized by city/municipal resolution; NPDES permit reqd for onshore discharges.
Oklahoma	Prohibited.	N/A		
Texas	Prohibited, unless fresh.	Discharges allowed, but skimming required to prevent oil in tidal waters; testing for oil every 30-40 days.		Individual permit
W. Virginia	No discharge of salt water or other water unfit for domestic livestock into waters of State.	N/A	Road application allowed pending study.	NPDES permit reqd for onshore discharges, general permit for stripper wells expected mid-1987.
Wyoming	Specs include O&G (10 mg/l) and Cl (2,000 mg/L); no discharge of toxic substances at conc. toxic to humans, animals, or aquatic life.	N/A		NPDES permit reqd for surface discharges.

Table VII-5 Produced Water Injection Well Construction

State	Casing	MIT pressure and duration	MIT frequency	Abandoned wells
Alaska	Safe and appropriate casing, cemented to protect oil, gas, and fresh water; detailed casing specs.	30 min at 1,500 psi or 0.25 psi/ft times vertical depth of casing shoe, whichever is greater; max. pressure decline 10%.	Before operation; thereafter monthly reporting of casing-tubing annulus pressure.	1/4-mile area of review.
Arkansas	Well must be cased and cemented so as not to damage oil, gas, or fresh water.	Determined by AOGC on a case-by-case basis.	Before operation; thereafter every 5 years.	1/2-mile area of review.
California	Safe and appropriate casing; cementing specs.	From hydrostatic to the pressure reqd to fracture the injection zone or the proposed injection pressure, whichever occurs first; step rate test may be waived.	Within 3 months after injection commences and annually thereafter, after any anomalous rate or pressure change, or as requested by DOG.	1/4-mile fixed radius in combination with radial flow equation and documented geological features are used to define area of review.
Colorado	Safe and adequate casing or tubing to prevent leakage, and cemented so as not to damage oil, gas, or fresh water.	15 min at 300 psi or the minimum injection pressure, whichever is greater; max. variance 10%.	Before operation, thereafter every 5 years; exceptions for wells monitoring annulus pressure monthly.	1/4-mile area of review; notice to surface and working interest owners within 1 mile.
Kansas	Well must be cased and cemented to prevent damage to hydrocarbon sources or fresh and usable water.	For old wells, 100 psi; for new wells, 100 psi or the authorized pressure, whichever is greater; alternative tests allowed; 30-minute test.	Before operation; thereafter every 5 years	1/4-mile area of review.
Louisiana	Casing must be set through the deepest USDW and cemented to the surface.	For new wells, 30 min at 300 psi, or max. allowable pressure, whichever is greater; for converted wells, the lesser of 1,000 psi or max. allowable pressure, but no lower than 300 psi; max. variance of 5 psi.	Before operation; thereafter every 5 years.	1/4-mile area of review.

Table VII-5 (continued)

State	Casing	MII pressure and duration	MII frequency	Abandoned wells
Michigan	Casing and seal to prevent the loss of produced water into an unapproved formation.	30 min at 300 psi, 3% allowable bleedoff.	As scheduled by RA (Federally administered).	State program to plug abandoned wells.
New Mexico	Casing or tubing to prevent leakage and fluid movement from the injection zone.	15-30 min at 250-300 psi; max. variance 10%.	Before operation, thereafter every 5 years; special test can be reqd more often; annulus monitoring required monthly.	State program to plug abandoned wells; 2 1/2-mile area of review, variance allowing no less than 1/4 mile; corrective action reqd to prevent migration through conduits.
Ohio	In addition to use of injection wells, annular disposal of produced water is allowed; max annular disposal 5-10 bbl/d; use only force of gravity; systems must be airtight.			
	Casing must be set at least 50 ft below the deepest USDW and must be cemented to the surface.	15 min at 300 psi, or max. allowable pressure, whichever is greater; max. decline 5%; alternative tests allowed.	Before operation; thereafter every 5 years.	1/4- to 1/2-mile area of review, depending on volume injected; well plugging fund.
Oklahoma	Casing must be set at least 90 ft below the surface or 50 ft below treatable water, whichever is lower, and must be cemented to the surface.	Same as Louisiana, except maximum bleedoff of 10%.	Before operation; thereafter every 5 years; exception for wells monitoring pressure monthly and reporting annually.	1/2-mile area of review; well plugging fund.
Texas	Surface casing cemented to surface; tubing and cemented casing string to isolate injection zone.	Test at 500 psig, or max. allowable pressure, whichever is less, but at least 200 psig; max. decline of 10%; once pressure stabilizes, 30 minutes with no variation.	Before injection, after workover, and thereafter every 5 years (exception for wells monitoring annulus pressure monthly and rpt'g annually, or for other viable alternative test).	1/4-mile area of review; notice to surface owners and offset operators; well plugging fund (main source: $100 drilling permit fee).

Table VII-5 (continued)

State	Casing	MIT pressure and duration	MIT frequency	Abandoned wells
W. Virginia		20 min at 1.5 to 2 times the injection pressure; max. variance 5%.	Every 5 years.	
Wyoming	Surface casing must be set below freshwater sources; casing cemented to the surface.	Same as Louisiana.	Before injection, thereafter every 5 years.	Notice to landowners and operators within 1/2 mile, 1/4-mile area of review.

Table VII-6 Well Abandonment/Plugging

States	Plugging deadline	Plugging oversight
Alaska	1 year following end of operator's activity within the field; if well not completed, must be abandoned or suspended before removal of drilling equipment; bridge plugs reqd for suspended wells.	Plugging method must be approved before beginning work; indemnity bond released after approval of well abandonment.
Arkansas	If not completed, must be abandoned/plugged before drilling equip. is released form the drilling operation; no time limit for temporary abandonment of properly cased well.	Plugging permit; onsite supervision by AOGC official; bond or other evidence of finanacial responsibility reqd, and released only after plugging/abandonment completed.
California	6 months after drilling activity ceases or 2 years after drilling equipment is removed; unless temp. abandonment of properly cased well.	Indemnity bond released after proper abandonment or completion is ensured.
Colorado	Generally, 6 months after production ceases; extensions require semi-annual status report.	Plugging method must be approved; COGC must have opportunity to witness; blanket or individual bond reqd.
Kansas	90 days after operations cease; where temporary abandonment, annual extensions require notice and status reports.	Plugging plan reqd before beginning work; report reqd after completion.
Louisiana	Within 90 days of notice in "Inactive Well Report" unless a plan is submitted describing the well's future use.	
Michigan	Within 60 days after cessation of drilling activities; within 1 year after cessation of production (with extensions, if sufficient reason to retain well).	Plugging method must be approved.

State	Plugging deadline	Plugging oversight
New Mexico	Generally, 6 months; extensions granted for up to 2 yr at a time	Well plugging plan must be approved; plugging bond released after inspection and Director approval.
Ohio	Immediately upon abandonment of a dry hole, without undue delay after prod ceases, extensions provided for 6 months.	Before plugging, approval reqd, after plugging, report reqd including identity of witnesses, liability insurance reqd; surety bond forfeited if noncompliance with regs.
Oklahoma	Where prod. casing has been run, 1 year after cessation of drilling (numerous exceptions); less time where no, or only surface, casing run, special rules for temporary abandonment.	Plugging must be supervised by an authorized rep. of the Conservation Division; plugging report reqd; proof of financial ability to comply with plugging reqt
Texas	Within 90 days after drilling or operations cease, except where cessation occurred in '66 or '67 (1 year); extensions at Director's discretion (if no pollution hazard) with plugging bond or letter of credit or plan to use for enhanced recovery.	Before plugging, notification and approval reqd, after plugging, report reqd; operator must be present during plugging.
W. Virginia	Prompt plugging reqd if dry holes and wells not in use for 12 mo; extensions for good cause.	Plugging bond and notif. to the Director and nearby coal operators reqd.
Wyoming	Approval from the State reqd if well is "temporarily abandoned" for more than 1 year.	Before plugging, approval reqd; after plugging, report reqd; well plugging bond released after the State inspection.

Table VII-7 State Enforcement Matrix

State	Gas Production	Oil Production	Gas wells	Oil wells	Injection wells	New wells	Agency	Personnel*
Alaska	316,000 Mmcf 1986	681,309,821 bbl 1986	104	1,191	472 Class II 425 EOR 47 Disposal	100 new onshore wells completed in 1985	Oil and Gas Conservation Commission Department of Environmental Conservation	8 enforcement positions 8 enforcement positions
Arkansas	194,483 Mmcf 1985	19,715,691 bbl 1985	2,492	9,490	1,211 Class II 239 EOR 972 Disposal	1,055 new wells completed in 1985	Arkansas Oil and Gas Commission Department of Pollution Control and Ecology	7 enforcement positions 2 enforcement positions
California	493,000 Mmcf 1985	423,900,000 bbl 1985	1,566	55,079	11,066 Class II 10,047 EOR 1,019 Disposal	3,413 new wells completed in 1985	Conservation Dept., Division of Oil and Gas Department of Fish and Game	31 enforcement positions
Kansas	466,600 Mmcf 1984	75,723,000 bbl 1984	12,680	57,633	14,902 Class II 9,366 EOR 5,536 Disposal	6,025 new wells completed in 1985	Kansas Corporation Commission	30 enforcement positions
Louisiana	5,867,000 Mmcf 1984	449,545,000 bbl 1984	14,436	25,823	4,436 Class II 1,283 EOR 3,153 Disposal	5,447 new onshore wells completed 1985	Department of Environmental Quality Office of Conservation - Injection and Mining	32 enforcement positions 36 enforcement positions
New Mexico	893,300 Mmcf 1985	78,500,000 bbl 1985	18,308	21,986	3,871 Class II 3,508 EOR 363 Disposal	1,747 new wells completed in 1985	Energy and Minerals Department, Oil Conservation Division	10 enforcement positions
Ohio	182,200 Mmcf 1985	14,987,592 bbl 1985	31,343	29,210	3,956 Class II 127 EOR 3,829 Disposal	6,297 new wells completed in 1985	Ohio Department of Natural Resources, Division of Oil and Gas	66 enforcement positions
Oklahoma	1,996,000 Mmcf 1984	153,250,000 bbl 1984	23,647	99,030	22,803 Class II 14,901 EOR 7,902 Disposal	9,176 new wells completed in 1985	Oklahoma Corporation Commission	52 enforcement positions
Pennsylvania	166,000 Mmcf 1984	4,825,000 bbl 1984	24,050	20,739	6,183 Class II 4,315 EOR 1,868 Disposal	4,627 new wells completed in 1985	Department of Environmental Resources, Bureau of Oil and Gas Management	34 enforcement positions
Texas	5,805,000 Mmcf 1985	830,000,000 bbl 1985	68,811	210,000	53,141 Class II 45,223 EOR 7,918 Disposal	25,721 new wells completed in 1985	Texas Railroad Commission	120 enforcement positions
West Virginia	142,500 Mmcf 1986	3,600,000 bbl 1986	32,500	15,895	761 Class II 687 EOR 74 Disposal	1,839 new wells completed in 1985	West Virginia Department of Energy	15 enforcement positions
Wyoming	597,896 Mmcf 1985	130,984,917 bbl 1985	2,220	12,218	5,880 Class II 5,257 EOR 623 Disposal	1,735 new wells completed in 1985	Oil and Gas Conservation Commission Department of Environmental Quality	7 enforcement positions 4.5 enforcement positions

*Only field staff are included in total enforcement positions.

Table VII-8 BLM Enforcement Matrix*

Office location	Other States for which office is responsible	Producing oil and gas leases	Nonproducing oil and gas leases**	Personnel (for producing leases only)
Alaska		43	8,443	1 enforcement position
California		305	1,383	7 enforcement positions
Colorado		3,973	4,463	10 enforcement positions
Idaho		0	471	0 enforcement positions
Mississippi		116	1,519	
	Alabama	12	567	
	Arkansas	161	1,099	
	Florida	1	0	
	Kentucky	13	65	
	Louisiana	121	487	
	Virginia	1	523	
	Total	425	4,260	3 enforcement positions
Montana		958	4,721	
	North Dakota	456	1,991	
	South Dakota	98	572	
	Total	1,512	7,284	12 enforcement positions
Nevada		43	3,045	1 enforcement position
New Mexico		5,725	9,306	
	Arizona	10	386	
	Kansas	150	227	
	Oklahoma	2,767	2,754	
	Texas	61	279	
	Total	8,713	12,952	43 enforcement positions
Oregon		0	1,513	0
Utah		1,654	7,222	10 enforcement positions
Wisconsin		0	0	
	Maryland	2	11	
	Michigan	28	603	
	Missouri	1	6	
	Ohio	33	69	
	Pennsylania	6	1	
	West Virginia	46	54	
	Total	116	844	1 enforcement position
Wyoming		5,037	28,044	
	Nebraska	42	582	
	Total	5,079	28,626	27 enforcement positions
	Total	22,037	102,251	115 enforcement positions

* Oil and gas inspectors working in the field as of March 30, 1987. At that time there were eight vacancies nationwide.

** Includes leases that have never been drilled, have been drilled and abandoned, or are producing wells that have been temporarily shut down.

REFERENCES

43 CFR 3100 (entire group).

U.S. Bureau of Land Management. (Not dated.) Federal Onshore Oil and Gas Leasing and Operating Regulations.

U.S. Bureau of Land Management. NTL-2B.

U.S. Department of the Interior - Geological Survey Division. (Not dated.) Notice to Lessees and Operators of Federal and Indian Oil and Gas Leases (NTL-2B).

Personal communication with Mr. Steve Spector, September 23, 1986.

CHAPTER VIII

CONCLUSIONS

From the analysis conducted for this report, it is possible to draw a number of general conclusions concerning the management of oil and gas wastes. These conclusions are presented below.

Available waste management practices vary in their environmental performance.

Based on its review of current and alternative waste management practices, EPA concludes that the environmental performance of existing waste management practices and technologies varies significantly. The reliability of waste management practices will depend largely on the environmental setting. However, some methods will generally be less reliable than others because of more direct routes of potential exposure to contaminants, lower maintenance and operational requirements, inferiority of design, or other factors. Dependence on less reliable methods can in certain vulnerable locations increase the potential for environmental damage related to malfunctions and improper maintenance. Examples of technologies or practices that are less reliable in locations vulnerable to environmental damage include:

- Annular disposal of produced water (see damage case OH 38, page IV-16);
- Landspreading or roadspreading of reserve pit contents (see damage case WV 13, page IV-24);
- Use of produced water storage pits (see damage case AR 10, page IV-36); and

- Surface discharges of drilling waste and produced water to sensitive systems such as estuaries or ephemeral streams (see damage cases TX 55, page IV-49; TX 31, page IV-50; TX 29, page IV-51; WY 07, page IV-60; and CA 21, page IV-68).

Any program to improve management of oil and gas wastes in the near term will be based largely on technologies and practices in current use.

Current technologies and practices for the management of wastes from oil and gas operations are well established, and their environmental performance is generally understood. Improvements in State regulatory requirements over the past several years are tending to increase use of more desirable technologies and practices and reduce reliance on others. Examples include increased use of closed systems and underground injection and reduced reliance on produced water storage and disposal pits.

Long-term improvements in waste management need not rely, however, purely on increasing the use of better existing technology. The Agency does foresee the possibility of significant technical improvements in future technologies and practices. Examples include incineration and other thermal treatment processes for drilling fluids; conservation, recycling, reuse, and other waste minimization techniques; and wet air oxidation and other proven technologies that have not yet been applied to oil and gas operations.

Because of Alaska's unique and sensitive tundra environment, there has been special concern about the environmental performance of waste management practices on the North Slope. Although there are limited and preliminary data that indicate some environmental impacts may occur, these data and EPA's initial analysis do not indicate the need to curtail current or future oil exploration, development, and production operations on the North Slope. However, there is a need for more environmental data on the performance of existing technology to provide assurance that future operations can proceed with minimal possible adverse impacts on this sensitive and unique environment. The State of Alaska has recently enacted new regulations which will provide additional data on these practices.

EPA is concerned in particular about the environmental desirability of two waste management practices used in Alaska: discharge of reserve pit supernatant onto tundra and road application of reserve pit contents as a dust suppressant. Available data suggest that applicable discharge limits have sometimes been exceeded. This, coupled with preliminary biological data on wildlife impacts and tundra and surface water impairment, suggests the need for further examination of these two practices with respect to current and future operations. The new regulations recently enacted by the State of Alaska should significantly reduce the potential for tundra and wildlife impacts.

Increased segregation of waste may help improve management of oil and gas wastes.

The scope of the exemption, as interpreted by EPA in Chapter II of this report, excludes certain relatively low-volume but possibly high-toxicity wastes, such as unused pipe dope, motor oil, and similar materials. Because some such wastes could be hazardous and could be segregated from the large-volume wastes, it may be appropriate to require that they be segregated and that some of these low-volume wastes be managed in accordance with hazardous waste regulations. While the Agency recognizes that small amounts of these materials may necessarily become mixed with exempt wastes through normal operations, it seeks to avoid any deliberate and unnecessary use of reserve pits as a disposal mechanism. Segregation of these wastes from high-volume exempt wastes appears to be desirable and should be encouraged where practical.

Although this issue is not explicitly covered in Chapter VII, EPA is aware that some States do require segregation of certain of these low-volume wastes. EPA does not have adequate data on which to judge whether these State requirements are adequate in coverage, are enforceable, are environmentally effective, or could be extended to general operations across the country. The Agency concludes that further study of this issue is desirable.

Stripper operations constitute a special subcategory of the oil and gas industry.

Strippers cumulatively contribute approximately 14 percent of total domestic oil production. As such, they represent an economically important component of the U.S. petroleum industry. Two aspects of the stripper industry raise issues of consequence to this study.

First, generation of production wastes by strippers is more significant than their total petroleum production would indicate. Some stripper wells yield more than 100 barrels of produced water for each barrel of oil, far higher on a percentage production basis than a typical new well, which may produce little or no water for each barrel of oil.

Second, stripper operations as a rule are highly sensitive to small fluctuations in market prices and cannot easily absorb additional costs for waste management.

Because of these two factors--inherently high waste-production rates coupled with economic vulnerability--EPA concludes that stripper operations constitute a special subcategory of the oil and gas industry that should be considered independently when developing recommendations for possible improvements in the management of oil and gas wastes. In the event that additional Federal regulatory action is contemplated, such special consideration could indicate the need for separate regulatory actions specifically tailored to stripper operations.

Documented damage cases and quantitative modeling results indicate that, when managed in accordance with State and Federal requirements, exempted oil and gas wastes rarely pose significant threats to human health and the environment.

Generalized modeling of human health risks from current waste management practices suggests that risks from properly managed operations are low. The damage cases researched in the course of this project, however, indicate that exempt wastes from oil and gas exploration, development, and production can endanger human health and cause environmental damage when managed in violation of existing State requirements.

Damage Cases

In a large portion of the cases developed for this study, the types of mismanagement that lead to such damages are illegal under current State regulations although a few were legal under State programs at the time when the damage originally occurred. Evidence suggests that violations of regulations do lead to damages. It is not possible to determine from available data how frequently violations occur or whether violations would be less frequent if new Federal regulations were imposed.

Documented damages suggest that all major types of wastes and waste management practices have been associated to some degree with endangerment of human health and damage to the environment. The principal types of wastes responsible for the damage cases include general reserve pit wastes (primarily drilling fluids and drill cuttings, but also miscellaneous wastes such as pipe dope, rigwash, diesel fuel, and crude oil); fracturing fluids; production chemicals; waste crude oil; produced water; and a variety of miscellaneous wastes associated with exploration, development, or production. The principal types of damage sometimes caused by these wastes include contamination of drinking-water aquifers and foods above levels considered safe for consumption, chemical contamination of livestock, reduction of property values, damage to native vegetation, destruction of wetlands, and endangerment of wildlife and impairment of wildlife habitat.

Risk Modeling

The results of the risk modeling suggest that of the hundreds of chemical constituents detected in both reserve pits and produced fluids, only a few from either source appear to be of concern to human health and the environment via ground-water and surface water pathways. The principal constituents of potential concern, based on an analysis of their toxicological data, their frequency of occurrence, and their mobility in ground water, include arsenic, benzene, sodium, chloride, boron, cadmium, chromium, and mobile salts. All of these constituents were included in the quantitative risk modeling; however, boron, cadmium, and chromium did not produce risks or resource damages under the conditions modeled.

For these constituents of potential concern, the quantitative risk modeling indicates that risks to human health and the environment are very small to negligible when wastes are properly managed. However, although the risk modeling employed several conservative assumptions, it was based on a relatively small sample of sites and was limited in scope to the management of drilling waste in reserve pits, the underground injection of produced water, and the surface water discharge of produced water from stripper wells. Also, the risk analysis did not consider migration of produced water contaminants through fractures or unplugged or improperly plugged and abandoned wells. Nevertheless, the relatively low risks calculated by the risk modeling effort suggest that complete adherence to existing State requirements would preclude most types of damages.

Damages may occur in some instances even where wastes are managed in accordance with currently applicable State and Federal requirements.

There appear to be some instances in which endangerment of human health and damage to the environment may occur even where operations are in compliance with currently applicable State and Federal requirements.

Damage Cases

Some documented damage cases illustrate the potential for human health endangerment or environmental damage from such legal practices as discharge to ephemeral streams, surface water discharges in estuaries in the Gulf Coast region, road application of reserve pit contents and discharge to tundra in the Arctic, annular disposal of produced waters, and landspreading of reserve pit contents.

Risk Modeling

For the constituents of potential concern, the quantitative evaluation did indicate some situations (less than 5 percent of those studied) with carcinogenic risks to maximally exposed individuals higher then 1 in 10,000 ($1x10^{-4}$) and sodium levels in excess of interim limits for public drinking water supplies. Although these higher risks resulted only under conservative modeling assumptions, including high (90th percentile) concentration levels for the toxic constituents, they do indicate potential for health or environmental impairment even under the general assumption of compliance with standard waste management procedures and applicable State and Federal requirements. Quantitative risk modeling indicates that there is an extremely wide variation (six or more orders of magnitude) in health and environmental damage potential among different sites and locations, depending on waste volumes, wide differences in measured toxic constituent concentrations, management practices, local hydrogeological conditions, and distances to exposure points.

Unplugged and improperly plugged abandoned wells can pose significant environmental problems.

Documentation assembled for the damage cases and contacts with State officials indicate that ground-water damages associated with unplugged and improperly plugged abandoned wells are a significant concern. Abandoned disposal wells may leak disposed wastes back to the surface or to usable ground water. Abandoned production wells may leak native brine, potentially leading to contamination of usable subsurface strata or surface waters.

Many older wells, drilled and abandoned prior to current improved requirements on well closure, have never been properly plugged. Many States have adequate regulations currently in place; however, even under some States' current regulations, wells are abandoned every year without being properly plugged.

Occasionally companies may file for bankruptcy prior to implementing correct plugging procedures and neglect to plug wells. Even when wells are correctly plugged, they may eventually leak in some circumstances in the presence of corrosive produced waters. The potential for environmental damage occurs wherever a well can act as a conduit between usable ground-water supplies and strata containing water with high chloride levels. This may occur when the high-chloride strata are pressurized naturally or are pressurized artificially by disposal or enhanced recovery operations, thereby allowing the chloride-rich waters to migrate easily into usable ground water.

Discharges of drilling muds and produced waters to surface waters have caused locally significant environmental damage where discharges are not in compliance with State and Federal statutes and regulations or where NPDES permits have not been issued.

Damage cases indicate that surface water discharges of wastes from exploration, development, and production operations have caused damage or danger to lakes, ephemeral streams, estuaries, and sensitive environments when such discharges are not carried out properly under applicable Federal and State programs and regulations. This is particularly an issue in areas where operations have not yet received permits under the Federal NPDES program, particularly along the Gulf Coast, where permit applications have been received but permits have not yet been issued, and on the Alaskan North Slope, where no NPDES permits have been issued.

For the Nation as a whole, Rrgulation of all oil and gas field wastes under unmodified Subtitle C of RCRA would have a substantial impact on the U.S. economy.

The most costly hypothetical hazardous waste management program evaluated by EPA could reduce total domestic oil production by as much as 18 percent by the year 2000. Because of attendant world price increases, this would result in an annual direct cost passed on to consumers of over $6 billion per year. This scenario assumes that 70 percent of all drilling and production wastes would be subject to the current requirements of Subtitle C of RCRA. If only 10 percent of drilling wastes and produced waters were found to be hazardous, Subtitle C regulation would result in a decline of 4 percent in U.S. production and a $1.2 billion cost increase to consumers, compared with baseline costs, in the year 2000.

EPA also examined the cost of a Subtitle C scenario in which produced waters injected for the purpose of enhanced oil recovery would be exempt from Subtitle C requirements. This scenario yielded production declines ranging from about 1.4 to 12 percent and costs passed on to consumers ranging from $0.7 to $4.5 billion per year, depending on whether 10 percent or 70 percent of the wastes (excluding produced waters injected for enhanced oil recovery) were regulated as hazardous wastes.

These Subtitle C estimates do not, however, factor in all of the Hazardous and Solid Waste Act Amendments relating to Subtitle C land disposal restrictions and corrective action requirements currently under regulatory development. If these two requirements were to apply to oil and gas field wastes, the impacts of Subtitle C regulation would be substantially increased.

The Agency also evaluated compliance costs and economic impacts for an intermediate regulatory scenario in which moderately toxic drilling wastes and produced waters would be subject to special RCRA requirements less stringent than those of Subtitle C. Under this scenario, affected drilling wastes would be managed in pits with synthetic liners, caps, and ground-water monitoring programs and regulated produced waters would continue to be injected into Class II wells (with no surface discharges allowed for produced waters exceeding prescribed constituent concentration limits). This scenario would result in a domestic production decline, and a cost passed on to consumers in the year 2000, of 1.4 percent and $400 million per year, respectively, if 70 percent of the wastes were regulated. If only 10 percent of the wastes were subject to regulation, this intermediate scenario would result in a production decline of less than 1 percent and an increased cost to consumers of under $100 million per year.

The economic impact analysis also estimates affects on U.S. foreign trade and State tax revenues. By the year 2000, based on U.S. Department of Energy models, the EPA cost results projected an increase in national petroleum imports ranging from less than 100 thousand to 1.1 million barrels per day and a corresponding increase in the U.S. balance of payments deficit ranging from less than $100 thousand to $18 billion annually, depending on differences in regulatory scenarios evaluated. Because of the decline in domestic production, aggregated State tax revenues would be depressed by an annual amount ranging from a few million to almost a billion dollars, depending on regulatory assumptions.

Regulation of all exempt wastes under full, unmodified RCRA Subtitle C appears unnecessary and impractical at this time.

There appears to be no need for the imposition of full, unmodified RCRA Subtitle C regulation of hazardous waste for all high-volume exempt oil and gas wastes. Based on knowledge of the size and diversity of the industry, such regulations could be logistically difficult to enforce and could pose a substantial financial burden on the oil and gas industry, particularly on small producers and stripper operations. Nevertheless, elements of the Subtitle C regulatory program may be appropriate in select circumstances. Reasons for the above tentative conclusion are described below.

The Agency considers imposition of full, unmodified Subtitle C regulations for all oil and gas exploration, development, and production wastes to be unnecessary because of factors such as the following.

- Damages and risks posed by oil and gas operations appear to be linked, in the majority of cases, to violations of existing State and Federal regulations. This suggests that implementation and enforcement of existing authorities are critical to proper management of these wastes. Significant additional environmental protection could be achieved through a program to enhance compliance with existing requirements.

- State programs exist to regulate the management of oil and gas wastes. Although improvements may be needed in some areas of design, implementation, or enforcement of these programs, EPA believes that these deficiencies are correctable.

- Existing Federal programs to control underground injection and surface water discharges provide sufficient legal authority to handle most problems posed by oil and gas wastes within their purview.

The Agency considers the imposition of full Subtitle C regulations for all oil and gas exploration, development, and production wastes to be impractical because of factors such as the following:

- EPA estimates that the economic impacts of imposition of full Subtitle C regulations (excluding the corrective action and land disposal restriction requirements), as they would apply without modification, would significantly reduce U.S. oil and gas production, possibly by as much as 22 percent.

- If reserve pits were considered to be hazardous waste management facilities, requiring permitting as Subtitle C land disposal facilities, the administrative procedures and lengthy application processes necessary to issue these permits would have a drastic impact on development and production.

- Adding oil and gas operations to the universe of hazardous waste generators would potentially add hundreds of thousands of sites to the universe of hazardous waste generators, with many thousands of units being added and subtracted annually.

- Manifesting of all drilling fluids and produced waters offsite to RCRA Subtitle C disposal facilities would pose difficult logistical and administrative problems, especially for stripper operations, because of the large number of wells now in operation.

States have adopted variable approaches to waste management.

State regulations governing proper management of Federally exempt oil and gas wastes vary to some extent to accommodate important regional differences in geological and climatic conditions, but these regional environmental variations do not fully explain significant variations in the content, specificity, and coverage of State regulations. For example, State well-plugging requirements for abandoned production wells range from a requirement to plug within 6 months of shutdown of operations to no time limit on plugging prior to abandonment.

Implementation of existing State and Federal requirements is a central issue in formulating recommendations in response to Section 8002(m).

A preliminary review of State and Federal programs indicates that most States have adequate regulations to control the management of oil and gas wastes. Generally, these State programs are improving. Alaska, for example, has just promulgated new regulations. It would be desirable, however, to enhance the implementation of, and compliance with, certain waste management requirements.

Regulations exist in most States to prohibit the use of improper waste management practices that have been shown by the damage cases to lead to environmental damages and endangerment of human health. Nevertheless, the extent to which these regulations are implemented and enforced must be one of the key factors in forming recommendations to Congress on appropriate Federal and non-Federal actions.

CHAPTER IX

RECOMMENDATIONS

Following public hearings on this report, EPA will draw more specific conclusions and make final recommendations to Congress regarding whether there is a need for new Federal regulations or other actions. These recommendations will be made to Congress and the public within 6 months of the publication of this report.

Use of Subtitle D and other Federal and State authorities should be explored as a means for implementing any necessary additional controls on oil and gas wastes.

EPA has concluded that imposition of full, unmodified RCRA Subtitle C regulation of hazardous waste for all exempt oil and gas wastes may be neither desirable nor feasible. The Agency believes, however, that further review of the current and potential additional future use of other Federal and State authorities (such as Subtitle D authority under RCRA and authorities under the Clean Water Act and the Safe Drinking Water Act) is desirable. These authorities could be appropriate for improved management of both exempt and nonexempt, high-volume or low-volume oil and gas wastes.

EPA may consider undertaking cooperative efforts with States to review and improve the design, implementation, and enforcement of existing State and Federal programs to manage oil and gas wastes.

EPA has concluded that most States have adequate regulations to control most impacts associated with the management of oil and gas wastes, but it would be desirable to enhance the implementation of, and compliance with, existing waste management requirements. EPA has also concluded that variations among States in the design and implementation of regulatory programs warrant review to identify successful measures in some States that might be attractive to other States. For example, EPA may want to explore whether changes in State regulatory reporting requirements would make enforcement easier or more effective. EPA therefore recommends additional work, in cooperation with the States, to explore these issues and to develop improvements in the design, implementation, and enforcement of State programs.

During this review, EPA and the States should also explore nonregulatory approaches to support current programs. These might include development of training standards, inspector training and certification programs, or technical assistance efforts. They might also involve development of interstate commissions or other organizational approaches to address waste management issues common to operations in major geological regions (such as the Gulf Coast, Appalachia, or the Southwest). Such commissions might serve as a forum for discussion of regional waste management efforts and provide a focus for development and delivery of nonregulatory programs.

The industry should explore the potential use of waste minimization, recycling, waste treatment, innovative technologies, and materials substitution as long-term improvements in the management of oil and gas wastes.

Although in the near term it appears that no new technologies are available for making significant technical improvements in the management of exempt wastes from oil and gas operations, over the long term various innovative technologies and practices may emerge. The industry should explore the use of innovative approaches, which might include conservation and waste minimization techniques for reducing generation of drilling fluid wastes, use of incineration or other treatment technologies, and substitution of less toxic compounds wherever possible in oil and gas operations generally.

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Groundwater-Quality and Quality-Control Data for Two Monitoring Wells near Pavillion, Wyoming, April and May 2012

Data Series 718

U.S. Department of the Interior
U.S. Geological Survey

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Conversion Factors

Inch/Pound to SI

Multiply	By	To obtain
	Length	
foot (ft)	0.3048	meter (m)
	Volume	
gallon (gal)	3.785	liter (L)
	Flow rate	
gallon per minute (gal/min)	0.06309	liter per second (L/s)
gallon per hour (gal/h)	3.785	liter per hour (L/h)
	Concentration	
part per million (ppm)	1.0	milligram per liter (mg/L)
part per billion	1.0	microgram per liter (µg/L)

Temperature can be converted to degrees Fahrenheit (°F) or degrees Celsius (°C) as follows:
°F=(1.8×°C)+32
°C=(°F-32)/1.8

Horizontal coordinate information is referenced to the North American Datum of 1983 (NAD 83).

Specific conductance is given in microsiemens per centimeter at 25 degrees Celsius (µS/cm at 25 °C).

Concentrations of most chemical constituents in water are given either in milligrams per liter (mg/L) or micrograms per liter (µg/L).

Abbreviations

>	greater than
<	less than
≤	less than or equal to
±	plus or minus
ASR	Analytical Services Request (U.S. Geological Survey)
bls	below land surface
$\delta^{13}C$	ratio of carbon-13 to carbon-12 isotopes in the sample relative to the ratio in a reference standard
CFC	chlorofluorocarbon
COC	chain-of-custody
DRO	diesel-range organics
GRO	gasoline-range organics
^{3}H	tritium (hydrogen-3)
$\delta^{2}H$	ratio of hydrogen-2 to hydrogen-1 isotopes in the sample relative to the ratio in a reference standard
^{3}He	ratio of helium-3 to helium-4 isotopes in the sample relative to the ratio in a reference standard
^{3}He	helium-3
^{4}He	helium-4
HCl	hydrochloric acid
NWIS	National Water Information System (U.S. Geological Survey)
NWQL	National Water Quality Laboratory (U.S. Geological Survey)
PAHs	polycyclic aromatic hydrocarbons
QC	quality control
RPD	relative percent difference
SAP	sampling and analysis plan (U.S. Geological Survey)
SC	specific conductance
SF_6	sulfur hexafluoride
SVOC	semivolatile organic compound
TICs	tentatively identified compounds
USEPA	U.S. Environmental Protection Agency
USGS	U.S. Geological Survey
VOC	volatile organic compound
WDEQ	Wyoming Department of Environmental Quality

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By Peter R. Wright, Peter B. McMahon, David K. Mueller, and Melanie L. Clark

Abstract

In June 2010, the U.S. Environmental Protection Agency installed two deep monitoring wells (MW01 and MW02) near Pavillion, Wyoming, to study groundwater quality. During April and May 2012, the U.S Geological Survey, in cooperation with the Wyoming Department of Environmental Quality, collected groundwater-quality data and quality-control data from monitoring well MW01 and, following well redevelopment, quality-control data for monitoring well MW02. Two groundwater-quality samples were collected from well MW01—one sample was collected after purging about 1.5 borehole volumes, and a second sample was collected after purging 3 borehole volumes. Both samples were collected and processed using methods designed to minimize atmospheric contamination or changes to water chemistry. Groundwater-quality samples were analyzed for field water-quality properties (water temperature, pH, specific conductance, dissolved oxygen, oxidation potential); inorganic constituents including naturally occurring radioactive compounds (radon, radium-226 and radium-228); organic constituents; dissolved gasses; stable isotopes of methane, water, and dissolved inorganic carbon; and environmental tracers (carbon-14, chlorofluorocarbons, sulfur hexafluoride, tritium, helium, neon, argon, krypton, xenon, and the ratio of helium-3 to helium-4). Quality-control sample results associated with well MW01 were evaluated to determine the extent to which environmental sample analytical results were affected by bias and to evaluate the variability inherent to sample collection and laboratory analyses. Field documentation, environmental data, and quality-control data for activities that occurred at the two monitoring wells during April and May 2012 are presented.

Introduction

Groundwater is the primary source of domestic water supply for the town of Pavillion, Wyoming, and its rural residential neighbors. On December 8, 2011, the U.S. Environmental Protection Agency (USEPA) released the draft report *Investigation of Ground Water Contamination near Pavillion, Wyoming* (U.S. Environmental Protection Agency, 2011) for public review. The report described and interpreted data collected for two USEPA monitoring wells from 2010 to 2011, and indicated that groundwater may contain chemicals associated with gas production practices. The Wyoming Department of Environmental Quality (WDEQ) wanted additional groundwater-quality samples collected from these USEPA monitoring wells and discussed this need with the U.S. Geological Survey (USGS) Wyoming Water Science Center. The monitoring wells are identified as wells MW01 and MW02. During April and May 2012, the USGS, in cooperation with the WDEQ, collected groundwater-quality and associated quality-control (QC) data from monitoring well MW01, and redeveloped and collected QC data from monitoring well MW02.

Both USEPA monitoring wells were installed during the summer of 2010 as part of a multi-phase investigation of groundwater quality in the Pavillion area (U.S. Environmental Protection Agency, 2011). Well MW01 was completed to a depth of 785 feet (ft) below land surface (bls) and well MW02 was completed to a depth of 980 ft bls. Both wells have a 20-ft screened interval. A dedicated submersible 3-horsepower pump was installed in each well. Detailed construction information for both wells is presented in the USEPA report (U.S. Environmental Protection Agency, 2011).

Well MW01 was purged and sampled by the USGS and USEPA on April 24, 2012. Only data collected by the USGS are presented in this report. The USGS collected two groundwater-quality (environmental) samples from well MW01—one sample was collected after purging about 1.5 borehole volumes of water from the well, and a second sample was collected after purging 3 borehole volumes. QC samples were collected in conjunction with both environmental samples from well MW01.

Using well hydraulic data collected in 2011, the USEPA estimated a yield of about 1 gallon per hour, or about 0.017 gallon per minute from well MW02 (U.S. Environmental Protection Agency, oral commun., 2012). Because of low yield, resulting in long recovery or purge times relative to the standard procedures and recommendations given in the

USGS National Field Manual (U.S. Geological Survey, variously dated), well MW02 was redeveloped by the USGS in an attempt to increase well yield. A description of the USGS efforts to redevelop well MW02 during the week of April 30, 2012, is provided in the *Sampling and Analysis Plan for the Characterization of Groundwater Quality in Two Monitoring Wells near Pavillion, Wyoming* (SAP) (Wright and McMahon, 2012). After well MW02 was redeveloped, well yield data were collected by the USEPA with assistance from the USGS. These data are described in the USGS SAP (Wright and McMahon, 2012). Well yield was not increased as a result of the redevelopment effort; consequently, well MW02 was not sampled for this study. Nevertheless, QC samples were collected to characterize water added to well MW02 during redevelopment, and to ensure that a downhole camera used to examine the well screen was clean. Analytical results for the QC samples associated with redevelopment of well MW02 are presented in this report.

Description of Study Area

The study area is in Fremont County near the town of Pavillion, Wyoming (fig. 1). This small, sparsely populated agricultural community of 231 people (U.S. Census Bureau, 2010) is composed primarily of large-acreage irrigated farms. Natural-gas development began in the area northeast of Pavillion in the early 1960s, increased in the 1980s, and in recent years has increased again, under a succession of different owner-operators (James Gores and Associates, 2011). The town of Pavillion and rural households in the area obtain their water supply from wells installed in the areally extensive, Tertiary-age (Eocene) Wind River Formation (James Gores and Associates, 2011) that underlies the town and adjacent areas.

Purpose and Scope

The purposes of this report are to present (1) the analytical results for groundwater-quality samples collected from USEPA well MW01 during April 2012; (2) analytical results for QC samples collected in association with sampling of well MW01 during April 2012; and (3) analytical results for QC samples collected in association with USGS redevelopment of USEPA well MW02 during May 2012. Methods used to collect and analyze the groundwater-quality and QC samples are described in the Methods section. Groundwater-quality samples were analyzed for field water-quality properties (water temperature, pH, specific conductance, dissolved oxygen, oxidation potential); inorganic constituents including naturally occurring radioactive compounds (radon, radium-226 and radium-228); organic constituents; dissolved gasses; stable isotopes of methane, water, and dissolved inorganic carbon; and environmental tracers [carbon-14, chlorofluorocarbons (CFCs), sulfur hexafluoride (SF_6), tritium (^3H), helium, neon, argon, krypton, and xenon , and the ratio of helium-3 to helium-4 isotopes in the sample relative to the ratio in a reference standard (δ^3He)].

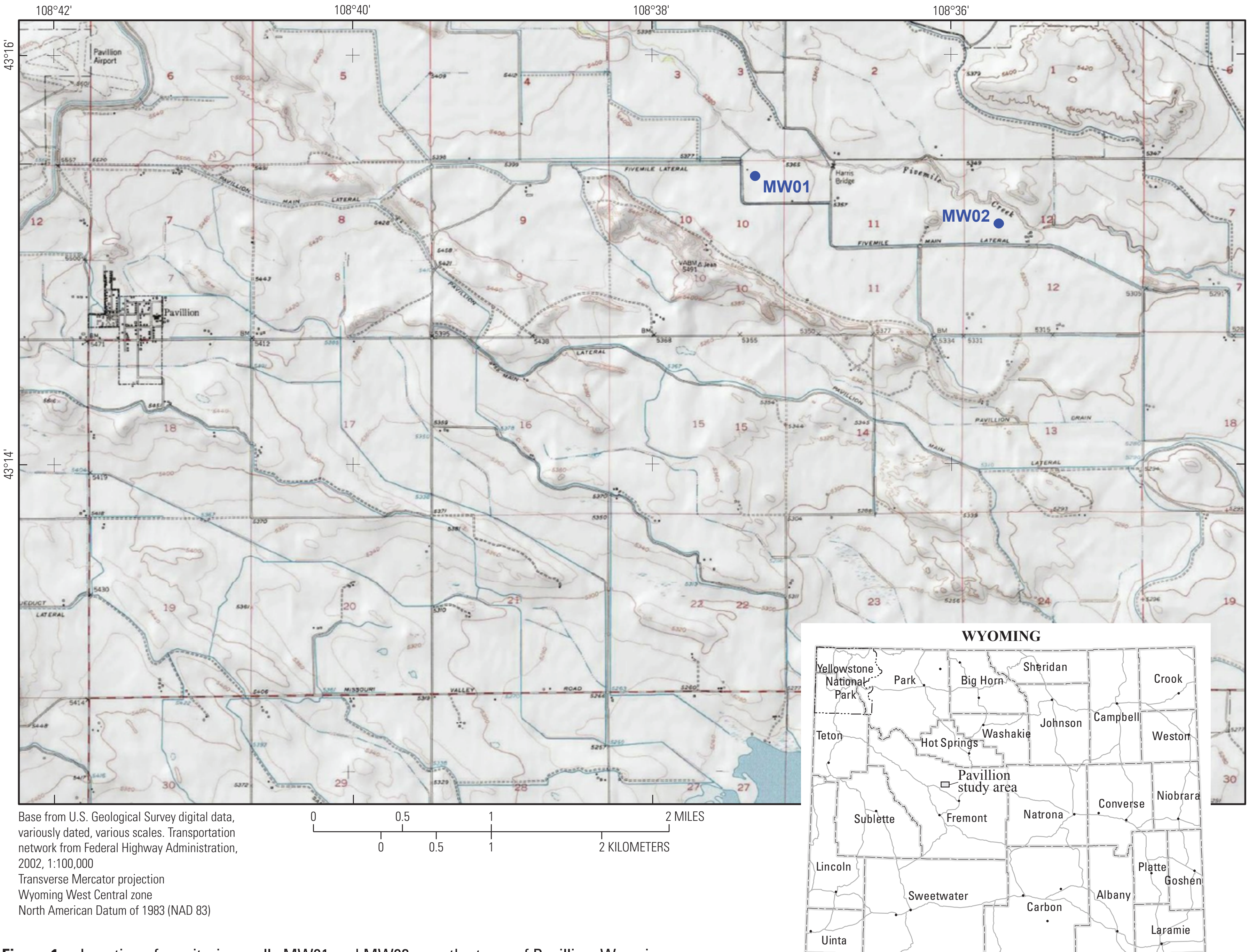
Methods

Samples collected during this study included two groundwater-quality samples from well MW01, several QC samples associated with well MW01, and two QC samples related to the redevelopment of well MW02. A brief description of the sampling design and sample collection at well MW01, the collection of QC samples related to well MW02 redevelopment, and methods used for laboratory and quality-control analyses are presented in this section.

Sampling Design

Groundwater-quality and QC samples were collected and processed using procedures described in the *Sampling and Analysis Plan for the Characterization of Groundwater Quality in Two Monitoring Wells near Pavillion, Wyoming* (SAP) (Wright and McMahon, 2012). A brief summary of the field sampling design described in the SAP is provided in this section.

Collection of two sets of groundwater-quality samples was planned for well MW01. The first sample set (environmental sample 1) was to be collected after one borehole volume of water was purged from the well. For this study, a borehole volume is defined as the wetted volume of unscreened casing plus the borehole volume throughout the screened interval, but excluding the volume of prepacked sand adjacent to the screened interval. An example of how the borehole volume was calculated is included in Wright and McMahon (2012). Sample collection also was contingent on stabilization of water temperature, specific conductance (SC), and pH of the water in successive field measurements. Stabilization of these properties was evaluated on the basis of the variability of five consecutive measurements made during a period of about 20 minutes at regularly timed intervals (Wilde, variously dated) (table 1). Water-quality properties are listed in table 1 (water temperature, SC, pH, dissolved oxygen, turbidity, and oxidation-reduction potential) that regularly are collected during groundwater sampling. Based on data USEPA had collected from well MW01, including low dissolved oxygen concentrations and excessive degassing in the sampling line, measurements of three of the properties (dissolved oxygen, turbidity, and oxidation-reduction potential) were thought to be less reliable than measurements of temperature, SC, and pH; therefore, the properties of dissolved oxygen, turbidity, and oxidation-reduction potential were not used as stabilization criteria. The second sample set (environmental sample 2) was to be collected after removal of three borehole volumes of water; sample collection was contingent on meeting the stabilization criteria for the same three field water-quality properties. In addition to the environmental samples, many different types of QC samples were proposed for the study. Three blank samples were scheduled to be collected before the well purge began (a source-solution blank, ambient blank, and a field blank), three replicate QC



Base from U.S. Geological Survey digital data, variously dated, various scales. Transportation network from Federal Highway Administration, 2002, 1:100,000
Transverse Mercator projection
Wyoming West Central zone
North American Datum of 1983 (NAD 83)

0 0.5 1 2 MILES
0 0.5 1 2 KILOMETERS

Figure 1. Location of monitoring wells MW01 and MW02 near the town of Pavillion, Wyoming.

samples were scheduled to be collected with each environmental sample (a replicate, matrix spike, and matrix-spike duplicate), and a trip blank traveled with sample bottles at all times. These QC sample types are defined in the SAP (Wright and McMahon, 2012).

Sample Collection at Monitoring Well MW01

On April 23 and 24, 2012, the USGS collected several blank samples, two groundwater-quality (environmental) samples, and several QC samples from monitoring well MW01 (table 2.) The USGS 15-digit site number and the date and time each sample was collected are shown in table 2. Sample collection generally followed the sampling design described in the SAP (Wright and McMahon, 2012), with a few modifications as described in this section. Documentation of field activities at monitoring well MW01 including field instrument calibration notes, general project notes, groundwater-quality notes for samples 1 and 2, purge logs, and alkalinity/acid-neutralizing capacity titration field notes are included in appendix 1 (figs. 1.1-1.4). As planned, three QC samples (source-solution blank, ambient blank, and field blank) were collected before beginning the well purge.

USEPA personnel measured the water level in well MW01 before and during the well purge using a sonic water-level meter. USEPA personnel also measured the pumping rate during the well purge. The pumping rate was measured using a flow meter and was verified using a bucket and a stopwatch.

Collection of environmental sample 1 and the associated QC samples was intended to begin after one borehole volume of water was purged from the well. Once a sufficient volume had been purged, sample collection started as soon as values for both SC and pH met stabilization criteria (table 1). The stabilization criterion for temperature was not used because the water line was exposed to solar heating and air temperature, so by the time water temperature was measured it was not a good indication of conditions in the well. Turbidity was not a stabilization criterion, and a turbidity sensor was not included on the multiparameter water-quality instrument. Only two turbidity measurements were made (sample aliquots collected from the sample discharge line and turbidity measured with a HACH 2100P meter; Hach Chemical Company, 2008) and noted on the purge log; both were very low, and were similar to each other. Values of SC met the criterion only briefly, but by then sampling had begun. Because it took longer for field water-quality properties of SC and pH to reach stability (based on criteria in table 1), collection of environmental sample 1 and associated QC samples actually began after about 1.5 borehole volumes had been purged from well MW01.

Table 1. Stabilization criteria and calibration guidelines for water-quality properties (modified from Wilde, variously dated).

[±, plus or minus value shown; °C, degrees Celsius; ≤, less than or equal to value shown; µS/cm, microsiemens per centimeter at 25°C; >, greater than value shown; NA, not applicable; NTRU, nephelometric turbidity ratio units; <, less than value shown; mg/L, milligrams per liter]

Water-quality property	Stabilization criteria[1] (variability should be within value shown)	Calibration guidelines
Temperature:		Calibrate annually, check calibration quarterly.
Thermistor	±0.2°C	
Specific conductance (SC):		Calibrate each morning and at end of each day. Check calibration at each additional site; recalibrate if not within 3 to 5 percent of standard value.
for ≤100 µS/cm at 25°C	±5 percent	
for >100 µS/cm at 25°C	±3 percent	
pH: (displays to 0.01 standard units)	±0.1 standard pH units. Allow ±0.3 pH units if drifting persists.	Calibrate each morning and at end of each day. Check calibration at each additional site; recalibrate if not within 0.05 pH units of standard .
Dissolved oxygen: Amperometric or optical/ luminescent-method sensors	NA[2]	Calibrate each morning and at end of each day. If electrode uses a Teflon® membrane, inspect electrode for bubbles under membrane at each sample site; replace if necessary.
Turbidity:	NA[2]	Calibrate with a primary standard on a quarterly basis. Check calibration against secondary standards (HACH GELEX) each morning and at end of each day; recalibrate if not within 5 percent.
Oxidation-reduction potential	NA[2]	Check against Zobell's solution each morning and at end of each day. Recalibrate if not within ±5 millivolts.

[1]Allowable variation between five or more sequential field measurements.

[2]These field-measured properties were not used in this study as stabiliization criteria. However, the following criteria were still considered while evaluating other properties: for dissolved oxygen, ±0.2 to ±0.3 mg/L; for turbidity, ±0.5 NTRU or 5 percent of the measured value, whichever is greater when <100 NTRU; oxidation-reduction potential was not used as a stabilzation criterion; however, this property can provide useful information for groundwater studies.

Table 2. Environmental and quality-control samples collected for monitoring wells MW01 and MW02 near Pavillion, Wyoming, April and May 2012.

[USGS, U.S. Geological Survey; NWQL, National Water Quality Laboratory; IBW, inorganic free blank water; OWB, organic free blank water]

Sample	Sample collection date	Type of water	Assigned sample time
Well MW01 (431525108371901)			
Source-solution blank	4/23/2012	USGS NWQL certified IBW and OBW	2000
Ambient blank	4/24/2012	USGS NWQL certified IBW and OBW	0800
Field blank	4/24/2012	USGS NWQL certified IBW and OBW	0830
Primary environmental sample 1	4/24/2012	Environmental water	1330
Sample 1 replicate	4/24/2012	Environmental water	1331
Matrix spike	4/24/2012	Environmental water	1332
Matrix-spike duplicate	4/24/2012	Environmental water	1333
Trip blank	4/24/2012	Laboratory-prepared blank water	1334
Primary environmental sample 2	4/24/2012	Environmental water	1830
Sample 2 replicate	4/24/2012	Environmental water	1831
Well MW02 (431511108354101)			
Riverton development water	5/1/2012	City of Riverton public-supply system water	1000
Trip blank	5/1/2012	Laboratory-prepared blank water	1004
Camera blank	5/1/2012	USGS NWQL certified IBW and OBW	1700

In addition to collection of environmental sample 1, all the planned QC samples (replicate, matrix spike, and matrix-spike duplicate samples) were collected. Laboratory analyses for each sample are listed in table 3. Sample collection was sequential; collecting a full set of containers for each analytical method—first, the environmental sample was collected; then, the replicate sample was collected; finally, the matrix spike and matrix-spike duplicate were collected. All water samples sent to the TestAmerica, Eberline, Woods Hole Oceanographic Institute, and USGS Tritium laboratories were collected inside a sampling chamber (a polyvinyl chloride frame with a clear plastic bag mounted inside, reducing sample exposure to airborne contamination sources) located within a mobile water-quality laboratory. The sample for analysis of the ratio of carbon-13 to carbon-12 isotopes ($\delta^{13}C$) of dissolved inorganic carbon, sent to the USGS Reston Stable Isotopes laboratory, also was collected inside the sampling chamber. After these samples were collected, dissolved gas, radon, remaining isotopes, and environmental tracer samples were collected outside of the mobile laboratory next to the well head. For each of these analyses, different sampling equipment was required such that the sampling chamber in the mobile laboratory could not be used; however, airborne contamination sources were not a concern. The SAP provides additional information on collection of these types of samples (Wright and McMahon, 2012).

All matrix spike and matrix-spike duplicate samples were spiked at the laboratory. Analytical Services Request (ASR) forms and chain-of-custody (COC) records are presented in appendix 2 (figs. 2.1–2.9). Photographs of groundwater-sampling activities are presented in appendix 3 (figs. 3.1–3.16).

Samples for analysis of some organic constituents were collected in duplicate with one set of bottles preserved with hydrochloric acid (HCl) and a second bottle set unpreserved. Field data collected by the USEPA during previous investigations of well MW01 indicated the pH of the groundwater would be greater than 11. Samples for volatile organic compounds (VOCs), gasoline-range organics (GRO), and some of the hydrocarbon gasses [ethane, ethylene, methane, and propane analyzed by USEPA method RSKSOP-175 (U.S. Environmental Protection Agency, 1994)] commonly are preserved by adding HCl to each sample container at the time of sample collection to lower the pH to less than 2, thus extending the sample holding time (time before a sample must be analyzed by a laboratory). Because HCl reactions within these samples potentially could cause gas loss resulting in a decrease in constituent recoveries, two bottle sets were sequentially collected for VOCs, GRO, and hydrocarbon gasses. One set of bottles was preserved with HCl at the time of collection and the second bottle set was left unpreserved.

Collection of environmental sample 2 began after three borehole volumes of water were purged from well MW01. Because collection of sample 2 began late in the day (time 1830) and it would not be safe to complete field activities after dark, the matrix spike and matrix-spike duplicate samples were not collected. In the end, a full suite of samples was collected for the environmental sample and a partial suite of samples was collected in replicate (table 3).

Field water-quality properties measured during the purge of well MW01 are presented in table 4.

Table 3. Analyses done for environmental and quality-control samples collected for monitoring wells MW01 and MW02 near Pavillion, Wyoming, April and May 2012.

[--, sample not collected; X, sample collected; USEPA, U.S. Environmental Protection Agency; mod, modified; SIM, selective ion monitoring; DAI, direct aqueous injection; BTEX, the compounds benzene, toluene, ethyl benzene, and xylene; MTBE, methyl tert-butyl ether; N_2, nitrogen; Ar, argon; CH_4, methane; CO_2, carbon dioxide; O_2, oxygen; $\delta^{18}O$, ratio of oxygen-18 to oxygen-16 isotopes in the sample relative to the ratio in a reference standard; $\delta^{2}H$, ratio of hydrogen-2 to hydrogen-1 isotopes in the sample relative to the ratio in a reference standard; $\delta^{13}C$, ratio of carbon-13 to carbon-12 isotopes in the sample relative to the ratio in a reference standard; $\delta^{3}He$, ratio of helium-3 to helium-4 isotopes in the sample relative to the ratio in a reference standard]

Laboratory analytical method[1]	Analysis	Analysis group	MW01										MW02		
			Source solution blank	Ambient blank	Field blank	Environmental sample 1	Sample 1 replicate	Matrix spike	Matrix spike duplicate	Trip blank	Environmental sample 2	Sample 2 replicate	Riverton development water	Trip blank	Camera blank
U.S. Geological Survey field analyses															
	Ferrous iron, field	Inorganic constituents	--	--	--	X	--	--	--	--	X	--	--	--	--
	Dissolved oxygen, low range, field	Inorganic constituents	--	--	--	X	--	--	--	--	X	--	--	--	--
	Alkalinity and associated constituents, field	Inorganic constituents	--	--	--	X	--	--	--	--	X	--	--	--	--
	Acid neutralizing capacity and associated constituents, field	Inorganic constituents	--	--	--	X	--	--	--	--	X	--	--	--	--
TestAmerica Laboratories															
USEPA method 6010B	Major cations and silica	Inorganic constituents	--	X	X	X	X	X	X	--	X	--	X	X	X
USEPA method 9056	Major anions	Inorganic constituents	--	X	X	X	X	X	X	--	X	--	X	X	X
USEPA method 350.1	Nitrogen, ammonia	Inorganic constituents	--	X	X	X	X	X	X	--	X	--	X	X	X
USEPA method 353.2	Nitrate + nitrite	Inorganic constituents	--	X	X	X	X	X	X	--	X	--	X	X	X
USEPA method 365.1	Phosphorus, dissolved	Inorganic constituents	--	X	X	X	X	X	X	--	X	--	X	X	X
USEPA method 6010B and 6020	Trace elements	Inorganic constituents	--	X	X	X	X	X	X	--	X	--	X	X	X
USEPA method 7470	Mercury	Inorganic constituents	--	X	X	X	X	X	X	--	X	--	X	X	X
USEPA method 8260B	Volatile organic compounds (VOCs)	Organic constituents	X	X	X	X	X	X	X	X	X	X	X	X	X
USEPA method 8260B	Volatile organic compounds (VOCs), unpreserved	Organic constituents	X	X	X	X	X	X	X	X	X	X	--	--	--
USEPA method 8270C and 8270/SIM	Semivolatile organic compounds (SVOCs) and polycylic aromatic hydrocarbons (PAHs)	Organic constituents	--	X	X	X	X	X	X	--	X	X	X	X	X
EPA 8015B DAI in Water (8015B)	Diesel range organics (DRO)	Organic constituents	X	--	X	X	X	X	X	--	X	X	X	X	X

Table 3. Analyses done for environmental and quality-control samples collected for monitoring wells MW01 and MW02 near Pavillion, Wyoming, April and May 2012.—Continued

[--, sample not collected; X, sample collected; USEPA, U.S. Environmental Protection Agency; mod, modified; SIM, selective ion monitoring; DAI, direct aqueous injection; BTEX, the compounds benzene, toluene, ethyl benzene, and xylene; MTBE, methyl tert-butyl ether; N_2, nitrogen; Ar, argon; CH_4, methane; CO_2, carbon dioxide; O_2, oxygen; $\delta^{18}O$, ratio of oxygen-18 to oxygen-16 isotopes in the sample relative to the ratio in a reference standard; $\delta^{2}H$, ratio of hydrogen-2 to hydrogen-1 isotopes in the sample relative to the ratio in a reference standard; $\delta^{13}C$, ratio of carbon-13 to carbon-12 isotopes in the sample relative to the ratio in a reference standard; $\delta^{3}He$, ratio of helium-3 to helium-4 isotopes in the sample relative to the ratio in a reference standard]

Laboratory analytical method[1]	Analysis	Analysis group	MW01										MW02		
			Source solution blank	Ambient blank	Field blank	Environmental sample 1	Sample 1 replicate	Matrix spike	Matrix spike duplicate	Trip blank	Environmental sample 2	Sample 2 replicate	Riverton development water	Trip blank	Camera blank
USEPA 8015B DAI in Water (8015B)	Glycols, ethanol, isobutanol, isopropyl alcohol, n-butanol	Organic constituents	X	--	X	X	X	X	X	X	X	X	X	X	X
USEPA 8015B/8021 mod	Gasoline range organics (GRO) + BTEX + MTBE	Organic constituents	X	X	X	X	X	X	X	X	X	X	X	X	X
USEPA 8015B/8021 mod	Gasoline range organics (GRO) + BTEX + MTBE, unpreserved	Organic constituents	X	X	X	X	X	X	X	X	X	X	--	--	--
RSK-SOP 175	Methane, ethane, ethylene, and propane	Dissolved gases	X	X	X	X	X	X	X	X	X	X	X	X	X
RSK-SOP 175	Methane, ethane, ethylene, and propane (unpreserved)	Dissolved gases	X	X	X	X	X	X	X	X	X	X	--	--	--
USEPA method 425.1	Methylene blue active substances	Organic constituents	--	X	X	X	X	X	X	--	X	--	X	X	X
Eberline Laboratory															
	Radium-226 and radium-228	Inorganic constituents	--	--	--	X	--	--	--	--	X	--	--	--	--
U.S. Geological Survey National Water Quality Laboratory															
	Radon-222	Inorganic constituents	--	--	--	X	--	--	--	--	--	--	--	--	--
Isotech Laboratories, Inc.															
	Compositional analysis of hydrocarbon gasses	Dissolved gases	--	--	--	X[2]	--	--	--	--	X	--	--	--	--
	$\delta^{13}C$ and $\delta^{2}H$ of methane	Stable isotopes	--	--	--	X[2]	--		--	--	X	--	--	--	--
Lamont-Doherty Laboratory															
	Helium, neon, argon, krypton, xenon, and $\delta^{3}He$	Environmental tracers	--	--	--	X[3]	--	--	--	--	--	--	--	--	--
U.S. Geological Survey Reston Chlorofluorocarbon Laboratory															
	Dissolved gasses (N_2, Ar, CH_4, CO_2, O_2)	Dissolved gases	--	--	--	X	X	--	--	--	X	--	--	--	--
	Helium	Environmental tracers	--	--	--	X	--	--	--	--	X	--	--	--	--
	Chlorofluorocarbons (CFCs)	Environmental tracers	--	--	--	X	X	--	--	--	--	--	--	--	--
	Sulfur hexafluoride (SF_6)	Environmental tracers	--	--	--	X	X	--	--	--	X	--	--	--	--
U.S. Geological Survey Reston Stable Isotope Laboratory															
LC 1142	$\delta^{18}O$ and $\delta^{2}H$ of water	Stable isotopes	--	--	--	X	--	--	--	--	--	--	--	--	--

Table 3. Analyses done for environmental and quality-control samples collected for monitoring wells MW01 and MW02 near Pavillion, Wyoming, April and May 2012.—Continued

[--, sample not collected; X, sample collected; USEPA, U.S. Environmental Protection Agency; mod, modified; SIM, selective ion monitoring; DAI, direct aqueous injection; BTEX, the compounds benzene, toluene, ethyl benzene, and xylene; MTBE, methyl tert-butyl ether; N_2, nitrogen; Ar, argon; CH_4, methane; CO_2, carbon dioxide; O_2, oxygen; $\delta^{18}O$, ratio of oxygen-18 to oxygen-16 isotopes in the sample relative to the ratio in a reference standard; $\delta^{2}H$, ratio of hydrogen-2 to hydrogen-1 isotopes in the sample relative to the ratio in a reference standard; $\delta^{13}C$, ratio of carbon-13 to carbon-12 isotopes in the sample relative to the ratio in a reference standard; $\delta^{3}He$, ratio of helium-3 to helium-4 isotopes in the sample relative to the ratio in a reference standard]

Laboratory analytical method[1]	Analysis	Analysis group	MW01 Source solution blank	MW01 Ambient blank	MW01 Field blank	MW01 Environmental sample 1	MW01 Sample 1 replicate	MW01 Matrix spike	MW01 Matrix spike duplicate	MW01 Trip blank	MW01 Environmental sample 2	MW01 Sample 2 replicate	MW02 Riverton development water	MW02 Trip blank	MW02 Camera blank
						U.S. Geological Survey Menlo Park Tritium Laboratory									
LC 1565	Tritium	Environmental tracers	--	--	--	X[3]	--	--	--	--	--	--	--	--	--
						Woods Hole Oceanographic Institute									
LC 3212	$\delta^{13}C$ and carbon-14 of dissolved inorganic carbon	Stable isotopes and environmental tracers	--	--	--	X	--	--	--	--	X	--	--	--	--

[1]Laboratory analytical methods, approaches and method references are provided in table 3 of Wright and McMahon (2012).

[2]Sample was collected but could not be analyzed because of broken bottle.

[3]Sample was collected but has not yet been analyzed as of August 20, 2012.

Table 4. Field water-quality properties measured during purge of monitoring well MW01 near Pavillion, Wyoming, April 2012.

[Highlighted value indicates property met purge criteria[1] for last five measurements. ft, feet; BMP, below measuring point; gal/min, gallons per minute; °C, degrees Celsius; SC, specific conductance at 25 degrees Celsius; µS/cm, microsiemens per centimeter; DO, dissolved oxygen; mg/L, milligrams per liter; ORP, oxidation reduction potential; mV, millivolts; NTRU, nephelometric turbidity ratio units; --, no data; <, less than]

Time	Water level (ft BMP)	Draw down (ft)	Pumping rate (gal/min)	Volume (gallons)	Borehole volumes	Water Temperature (°C)	Variability[2] of last 5 temperature measurements	SC (µS/cm)	Variability[3] of last 5 SC measurements (percent)	pH (standard units)	Variability	DO (mg/L)	ORP (mV)	Turbidity (NTRU)	Comments
11:10	201.35	0.00	--	0	0.00	--	--	--	--		--	--	--	--	Pump started.
11:20	287.94	86.59	6.05	61	0.14	19.02	--	--	--	11.5	--	0.5	–170.50	--	
11:30	315.58	114.23	6.05	121	0.28	14.45	--	3,396	--	12.1	--	< 0.2	–236.30	--	
11:40	329.73	128.38	6.11	182	0.42	14.96	--	3,101	--	12.1	--	< 0.2	–248.20	--	
11:50	334.04	132.69	6.10	243	0.57	15.74	--	2,839	--	12.0	--	< 0.2	–262.80	--	
12:00	334.42	133.07	6.04	304	0.71	15.73	4.57	2,549	--	11.9	0.64	< 0.2	–272.80	--	
12:09	325.58	124.23	6.00	358	0.83	17.45	3.00	2,306	38.40	11.8	0.33	< 0.2	–283.00	--	Pumping rate decreased to 2.61.
12:15	301.47	100.12	2.63	373	0.87	12.83	4.62	2,087	39.36	11.8	0.30	< 0.2	–288.60	--	
12:20	294.34	92.99	2.50	386	0.90	14.60	4.62	2,181	31.43	11.8	0.23	< 0.2	–294.00	--	
12:25	287.15	85.80	2.58	399	0.93	14.52	4.62	1,930	28.00	11.7	0.21	< 0.2	–296.10	--	
12:30	281.73	80.38	2.58	412	0.96	14.55	4.62	1,831	22.98	11.6	0.17	< 0.2	–299.40	1.95	
12:35	278.47	77.12	2.60	425	0.99	14.45	1.77	1,812	18.75	11.6	0.21	< 0.2	–302.20	--	
12:40	278.48	77.13	2.68	438	1.02	14.31	0.29	1,735	23.50	11.6	0.21	< 0.2	–303.90	--	
12:45	273.66	72.31	2.52	451	1.05	15.11	0.80	1,763	10.75	11.5	0.16	< 0.2	–307.50	--	
12:50	271.89	70.54	2.56	463	1.08	14.54	0.80	1,751	5.40	11.5	0.10	< 0.2	–310.30	--	

Table 4. Field water-quality properties measured during purge of monitoring well MW01 near Pavillion, Wyoming, April 2012.—Continued

[Highlighted value indicates property met purge criteria[1] for last five measurements. ft, feet; BMP, below measuring point; gal/min, gallons per minute; °C, degrees Celsius; SC, specific conductance at 25 degrees Celsius; µS/cm, microsiemens per centimeter; DO, dissolved oxygen; mg/L, milligrams per liter; ORP, oxidation reduction potential; mV, millivolts; NTRU, nephelometric turbidity ratio units; --, no data; <, less than]

Time	Water level (ft BMP)	Draw down (ft)	Pumping rate (gal/min)	Volume (gallons)	Borehole volumes	Water Temperature (°C)	Variability[2] of last 5 temperature measurements	SC (µS/cm)	Variability[3] of last 5 SC measurements (percent)	pH (standard units)	Variability	DO (mg/L)	ORP (mV)	Turbidity (NTRU)	Comments
12:55	270.84	69.49	2.59	476	1.11	14.53	0.80	1,757	4.37	11.5	0.06	< 0.2	–312.70	--	
13:00	269.96	68.61	2.65	490	1.14	15.09	0.80	1,701	3.56	11.5	0.05	< 0.2	–316.30	--	
13:05	269.24	67.89	2.55	502	1.17	14.86	0.58	1,704	3.57	11.5	0.03	< 0.2	–318.40	--	
13:12	268.41	67.06	2.57	520	1.21	14.18	0.91	1,700	3.31	11.5	0.04	< 0.2	–319.90	1.22	
13:15	268.24	66.89	2.59	528	1.23	14.19	0.91	1,737	3.31	11.5	0.03	< 0.2	–320.70	--	
13:31	267.92	66.57	2.58	569	1.33	14.57	0.91	1,665	4.23	11.5	0.05	< 0.2	–328.10	--	
13:40	266.64	65.29	2.62	593	1.38	15.04	0.86	1,657	4.73	11.5	0.06	< 0.2	–335.50	--	
13:48	266.42	65.07	2.52	613	1.43	14.89	0.86	1,635	6.08	11.4	0.08	< 0.2	–336.70	--	
13:56	265.21	63.86	2.63	634	1.48	15.54	1.35	1,642	6.12	11.4	0.10	< 0.2	–340.20	--	
14:10	266.21	64.86	2.46	669	1.56	14.99	0.97	1,621	2.68	11.4	0.10	< 0.2	–343.70	--	Collection of environmental sample 1 began.
14:20	266.37	65.02	2.32	692	1.61	15.77	0.88	1,602	3.37	11.3	0.12	< 0.2	–347.60	--	
14:30	261.41	60.06	2.18	714	1.66	15.45	0.88	1,566	4.71	11.3	0.12	< 0.2	–349.80	--	
14:45	268.03	66.68	2.63	753	1.76	15.47	0.78	1,519	7.74	11.3	0.16	< 0.2	–355.50	--	
15:15	268.56	67.21	2.63	832	1.94	14.92	0.85	1,459	10.43	11.2	0.15	< 0.2	–360.80	--	
15:30	268.50	67.15	2.67	872	2.03	14.81	0.96	1,442	10.54	11.2	0.15	< 0.2	–364.40	--	
15:45	268.60	67.25	2.59	911	2.12	14.88	0.66	1,455	8.33	11.1	0.18	< 0.2	–368.40	--	
16:00	269.94	68.59	2.70	951	2.22	15.10	0.66	1,458	5.25	11.1	0.18	< 0.2	–371.40	--	
16:15	269.00	67.65	2.67	991	2.31	15.34	0.53	1,401	4.02	11.0	0.18	< 0.2	–374.90	--	
16:30	269.22	67.87	2.30	1,026	2.39	15.39	0.58	1,426	3.97	11.0	0.20	< 0.2	–377.80	--	
16:45	269.33	67.98	2.67	1,066	2.48	15.14	0.51	1,401	3.99	11.0	0.17	< 0.2	–380.30	--	
17:00	269.55	68.20	2.59	1,105	2.58	15.05	0.34	1,403	4.02	10.9	0.16	< 0.2	–382.20	--	
17:15	269.83	68.48	2.23	1,138	2.65	15.31	0.34	1,416	1.77	10.9	0.17	< 0.2	–384.20	--	
17:30	269.93	68.58	2.58	1,177	2.74	15.10	0.34	1,396	2.13	10.8	0.15	< 0.2	–385.80	--	
17:35	269.88	68.53	2.52	1,190	2.77	15.04	0.27	1,380	2.57	10.8	0.15	< 0.2	–385.50	--	
17:40	269.82	68.47	2.61	1,203	2.80	15.08	0.27	1,392	2.58	10.8	0.11	< 0.2	–386.20	--	
17:45	269.99	68.64	2.57	1,215	2.83	15.02	0.29	1,393	2.58	10.8	0.07	< 0.2	–387.40	--	
17:50	269.98	68.63	2.57	1,228	2.86	14.96	0.14	1,398	1.29	10.8	0.03	< 0.2	–389.10	--	
17:55	270.04	68.69	2.62	1,241	2.89	15.01	0.12	1,378	1.44	10.8	0.03	< 0.2	–388.40	--	
18:00	270.04	68.69	2.44	1,254	2.92	15.09	0.13	1,373	1.80	10.7	0.06	< 0.2	–388.60	--	
18:05	270.09	68.74	2.59	1,267	2.95	14.86	0.23	1,380	1.81	10.7	0.06	< 0.2	–388.90	--	
18:10	270.15	68.80	2.47	1,279	2.98	14.93	0.23	1,379	1.81	10.7	0.06	< 0.2	–390.00	--	
18:15	270.15	68.80	2.61	1,292	3.01	14.86	0.23	1,373	0.51	10.7	0.07	< 0.2	–389.80	--	Collection of environmental sample 2 began.
18:25	270.31	68.96	2.42	1,316	3.07	14.58	0.51	1,379	0.51	10.7	0.05	< 0.2	–389.90	--	
18:35	270.42	69.07	2.09	1,337	3.12	14.71	0.35	1,383	0.73	10.7	0.07	< 0.2	–391.50	--	
18:45	270.31	68.96	2.49	1,362	3.17	14.71	0.35	1,382	0.73	10.7	0.08	< 0.2	–393.00	--	
19:00	270.15	68.80	2.10	1,393	3.25	15.07	0.49	1,375	0.73	10.6	0.12	< 0.2	–392.90	--	
19:15	270.09	68.74	2.39	1,429	3.33	14.74	0.49	1,385	0.72	10.6	0.11	< 0.2	–394.20	--	
19:27	270.19	68.84	2.73	1,462	3.41	14.58	0.49	1,373	0.87	10.6	0.10	< 0.2	–395.90	--	Pump shut off.

[1]Purge criteria for this sampling program are listed in table 1.

[2]Variability for this property was calculated by subtracting the minimum of the last five measurements from the maximum of the last five measurements.

[3]Variability for this property was calculated by subtracting the minimum of the last five measurements from the maximum of the last five measurements and dividing this result by the average of the last five measurements. The result is then multiplied by 100.

Redevelopment of Monitoring Well MW02 and Collection of Associated Quality-Control Samples

In an attempt to increase well yield, monitoring well MW02 was redeveloped by the USGS during the week of April 30, 2012. Redevelopment included surging the well and bailing from the top and the bottom of the water column. As part of the redevelopment effort, potable water obtained from the public water supply of the city of Riverton was added to well MW02 before pump removal in order to decrease methane concentrations in the well and reduce the explosion hazard. A sample of the Riverton water added to the well was collected to characterize its chemical quality. The sample was collected from a sampling port in the pumping line while water was recirculated through the pump, hose, and tank used by the driller to add water to well MW02. This water, identified as Riverton development water, was analyzed for the chemical constituents listed in table 3. Documentation of field activities, including instrumentation and sampling logs; ASR forms COC records; and photographs of field activities are in appendixes 4 (figs. 4.1–4.7), 5 (figs. 5.1–5.2), and 6 (figs. 6.1–6.6), respectively.

During redevelopment of well MW02, a downhole camera was used to view and evaluate the condition of the well casing and screen. Before deploying the downhole camera, an equipment blank was collected for the camera. This camera blank was collected by pouring blank water over the camera and collecting it in sample containers. The camera blank samples were analyzed for the chemical constituents listed in table 3.

Analytical Methods

Nine laboratories analyzed samples for this study: TestAmerica Laboratories in Arvada, Colorado, Woods Hole Oceanographic Institute-National Ocean Sciences Accelerator Mass Spectrometry Facility in Woods Hole, Massachusetts, and Eberline Laboratories in Richmond, Calif., under contract with the USGS National Water Quality Laboratory (NWQL) in Lakewood, Colorado; four USGS laboratories (NWQL, Reston Chlorofluorocarbon Laboratory, Reston Stable Isotope Laboratory, and Menlo Park Tritium Laboratory); Lamont-Doherty Earth Observatory Noble Gas Laboratory in Palisades, New York (contracted by the Reston Chlorofluorocarbon Laboratory); and Isotech Laboratories, Inc., in Champaign, Illinios. Analytical methods for each laboratory are listed in table 3. A list of analytical methods and method references are provided in table 3 of the SAP (Wright and McMahon, 2012).

Quality-Control Sample Collection and Data Analysis

Analytical results from QC samples collected in the field and prepared in the laboratories were used to assess the quality of data reported for environmental samples. Data from QC samples collected at well MW01 (table 2) were evaluated to determine whether qualification of environmental sample analytical data was warranted before use in interpretive reports. Specifically, QC sample results were used to evaluate the extent to which environmental data were affected by bias (for example, contamination of samples in the field or laboratory) and were used to evaluate the variability inherent to sample collection and laboratory analyses. The QC samples used to estimate bias included a variety of blanks, prepared with water that is certified free of analytes of interest (blank water), and samples that were spiked with known concentrations of target analytes. Variability was estimated by collecting replicate samples in the field and comparing the analytical results to results for the primary environmental samples.

Blank Samples

Procedures for the collection of field QC samples included in this report are described in the SAP (Wright and McMahon, 2012). Four types of blank samples were submitted to TestAmerica Laboratories for analysis: source-solution, ambient, field, and trip blanks. Each of these blank samples could have been subjected to contamination during various stages of sample collection, processing, shipping, and analysis. In addition, TestAmerica Laboratories provided results for a laboratory blank sample, prepared with reagent water. A quantified result in any blank sample was considered evidence that contamination could have affected environmental sample analytical results; consequently, analytical results for the two primary samples (environmental sample 1 and environmental sample 2) and associated replicates were compared to the maximum quantified concentration in the five blanks. In accordance with USEPA guidance (U.S. Environmental Protection Agency, 1989, p. 5–17), a reported concentration in an environmental sample that is less than five times the concentration in a related blank sample should be treated as a nondetection, and the reported concentration should be considered the quantitation limit for the analyte in that sample. These analytes are identified by a project data qualifier in the data tables (tables 5–14) presented in this report. Overall, results were qualified for 18 constituents detected in the 2 primary environmental samples. All these qualifications were based on quantified results in laboratory, ambient, or field blank samples; results for all analyses of source-solution and trip blank samples were less than method detection limits. For 13 of the constituents detected in blank samples, quantified concentrations were reported for more than 1 type of blank sample.

Laboratory Spike Samples

Laboratory reagent and matrix spike samples also contribute to evaluation of analytical bias that can affect results. This bias can be evaluated by determining the recovery of a known amount of an analyte that is spiked into reagent water or sample matrix (water collected at the field site). For this study, duplicate matrix spike samples were collected in addition to environmental sample 1. TestAmerica Laboratories spiked these matrix samples, as well as duplicate reagent samples, at the laboratory. Analyte recovery from matrix spike samples was calculated by adjusting for background concentration in the environmental sample using the following equation:

$$R = \frac{C_{ms} - C_{env}}{C_{spiked}} \times 100 \qquad (1)$$

where

R = analyte recovery, in percent

C_{ms} = concentration of the analyte in the matrix spike sample,

C_{env} = background concentration of the analyte in the environmental sample,

and C_{spiked} = concentration of the spiked analyte expected in the matrix sample.

All matrix spikes collected from well MW01 were associated with environmental sample 1, so analyte concentrations in that sample were used as background concentrations in recovery calculations. Analyte recovery in the laboratory reagent samples was calculated simply as the ratio of the analyte concentration in the matrix spike sample to the expected concentration of the spiked analyte, because no background concentrations were present.

Control limits on acceptable recovery are established by the analyzing laboratory for each analyte. Recoveries outside acceptable limits are identified in the laboratory data qualifiers column in the data tables presented in this report. In addition, the project data qualifiers identify analytes with recoveries less than 70 percent or greater than 130 percent. Although these recoveries do not necessarily correspond to control limits, they provide a consistent identification of analytes for which results might be low or high because of analytical bias. Another laboratory data qualifier identifies matrix samples for which the background concentration exceeds four times the spiked concentration, in which case recovery is uncertain and control limits are not applicable. In these cases, project data qualifiers for low and high bias also were considered inapplicable. Finally, project data qualifiers for high bias were not applied if the analyte concentration was censored (reported as less than the method detection limit), because, in this case, the potential bias did not have a measurable effect. Overall, the low-bias qualifier was applied to 10 constituents and the high-bias qualifier was applied to 4 constituents.

Replicate Samples

Potential variability in reported analyte concentrations is estimated by comparison of replicate samples. Replicates were collected for both environmental samples 1 and 2 from well MW01, although the replicate for environmental sample 2 was not analyzed for all analytes. Variability for each analyte is estimated as the relative percent difference (RPD) between the two replicates:

$$RPD = \frac{\left|C_{env} - C_{rep}\right|}{\left(C_{env} + C_{rep}\right)/2} \times 100 \qquad (2)$$

where

$|C_{env} - C_{rep}|$ = absolute value of the difference between concentrations of the analyte in the primary environmental sample and the replicate sample, and

$(C_{env} + C_{rep})/2$ = mean concentration of the analyte in the primary environmental sample and replicate sample.

The RPD cannot be calculated if the concentration is censored in either or both samples. For this study, RPD values greater than 20 percent were considered indicative that analytical results might be affected by high variability. Analytes with RPDs outside this criterion are identified with a project data qualifier on the primary environmental sample and replicate sample in the relevant data tables. Overall, eight constituents were qualified because of high variability in environmental sample 1, and three constituents were qualified in environmental sample 2.

In summary, four criteria for inclusion of project data qualifiers were applied to analytes in environmental samples and replicates:

1. Contamination bias: quantified concentration was less than five times the maximum concentration in a blank sample,
2. Recovery bias: potential low bias—recovery was less than 70 percent in one or more spike samples,
3. Recovery bias: potential high bias—recovery was greater than 130 percent in one or more spike samples (applied only to constituents with quantified results), and
4. Variability: RPD between the environmental sample and replicate sample was greater than 20 percent.

Major-Ion Balances

Major-ion data were quality assured by calculating a cation-anion balance. The sum of concentrations of dissolved cations in milliequivalents per liter should equal the sum of concentrations of dissolved anions in milliequivalents per liter (Hem, 1985). The percent difference between the sum of concentrations of cations and anions in milliequivalents per liter was calculated using equation 3.

$$\textit{Percent difference} = \left(\frac{\textit{sum of dissolved cations} - \textit{sum of dissolved anions}}{\textit{sum of dissolved cations} + \textit{sum of dissolved anions}}\right) \times 100 \qquad (3)$$

Groundwater-Quality Data

Results from analyses of groundwater and QC samples collected from monitoring well MW01 are presented in tables 5 through 11. Many organic constituents were collected in duplicate (one set of bottles preserved with HCl and a second bottle set unpreserved). To identify the preservation method used for each of the organic constituents, a column was added to tables 7 through 10 to indicate whether preservative was added to the sample bottle. Constituent concentrations for samples that were preserved using HCl are identified in the "preservative added to bottle" column with Yes, and constituent concentrations for samples that were unpreserved are identified with No. The QC samples collected for well MW02 are included in tables 12 through 14. Analytical results for tritium, some noble gasses (neon, krypton, and xenon), and helium isotope ratios had not been received as of August 17, 2012, and are not presented in this report; when received from the laboratories, analytical results for these constituents will be available through the USGS National Water Information System (NWIS) Web Interface, accessible at *http://waterdata.usgs.gov/wy/nwis/qw*. Analytical results for tritium have been added to table 11. The analysis for some noble gasses (neon, krypton, xenon) and helium isotope ratios were not completed due to a compromised sample container. Hence, analytical results for neon, krypton, xenon and helium isotope ratios are not available. The USGS 15-digit site number, sample collection dates, and times needed to access water-quality data using the NWIS Web Interface are listed in table 2.

Monitoring Well MW01

Field Water-Quality Properties and Hydrologic Data Measured During the Well Purge

Field water-quality properties and basic hydrologic data measured during the purge of monitoring well MW01 are listed in table 4. Field water-quality properties and basic hydrologic data were measured at regular intervals and recorded on a purge log (see appendix 1, figs. 1.16-1.20). Water levels and pumping rates were measured to calculate water-level drawdown in response to pumping and the total volume of water purged from the well. The water level in well MW01 during the purge and sampling is shown in figure 2*A*. Variability of water temperature, SC, and pH of the pumped water during purging also were evaluated (table 4). Values of specific conductance and pH are shown in relation to purge volume in figures 2*B* and 2*C*, respectively. A graph of water temperature is not included in this report because these data were affected by heating in the sampling line between the well and the point of measurement; therefore, they do not represent conditions in the well.

The borehole volume of water purged from well MW01 was calculated using equation 2 in the SAP (Wright and McMahon, 2012); one borehole volume was about 429 gallons. Sample collection began after this amount of water had been pumped and as soon as both SC and pH met stabilization criteria. Stabilization criteria were met and collection of environmental sample began at time 14:10 on April 24, 2012 (table 4), and although SC only met the stabilization criteria briefly, sampling had already begun. The sample time associated with environmental sample 1 (time 13:30 on April 24, 2012; table 2) had been assigned to the sample in advance, in anticipation of sample collection starting after one borehole volume had been purged from the well. Collection of a water sample from MW01 after purging one borehole volume of water had been a stated objective in the SAP (Wright and McMahon, 2012). Collection of environmental sample 1 and associated QC samples included the filling of 214 sample containers, equaling collection of approximately 18 gallons of water, and took more than 2 hours to complete.

Field Water-Quality Properties and Inorganic and Radioactive Constituents

Concentrations of inorganic constituents, including naturally occurring radioactive constituents (radon, radium-226, and radium-228), in the environmental samples and replicates collected from well MW01 are listed in table 5. The data for blank and spike samples are listed in table 6.

Samples were titrated in the field to determine alkalinity (filtered sample) and acid-neutralizing capacity (unfiltered sample). Based on these titration data, the USGS alkalinity calculator, which is described in Chapter A6, Section 6.6.5.C of the USGS National Field Manual (Wilde, variously dated), was used to calculate concentrations of bicarbonate, carbonate, and hydroxide.

Ionic charge balances calculated for environmental sample 1, sample 1 replicate, and environmental sample 2 were -1.94, 0.03, and 0.23 percent, respectively. An ionic charge balance within plus or minus 5 percent is considered acceptable (Clesceri and others, 1998). An ionic charge balance was not calculated for the sample 2 replicate because major ions were not included in the analysis of that sample set.

Of the inorganic constituents detected in the environmental samples (table 5), sodium and sulfate were measured at the highest concentrations. Six detected inorganic constituents (filtered magnesium and unfiltered ammonia, phosphorus, cadmium, thallium, and uranium) were measured at concentrations less than five times the maximum concentration detected in the blank samples. Quantified concentrations for several constituents in tables 5 and 6 include an "E" remark because the concentrations are less than the reporting level, but equal to or greater than the method detection limit. Most of the nondetected inorganic constituents are trace elements (for example, beryllium, chromium, cobalt, copper, lead, mercury, selenium, silver, and zinc).

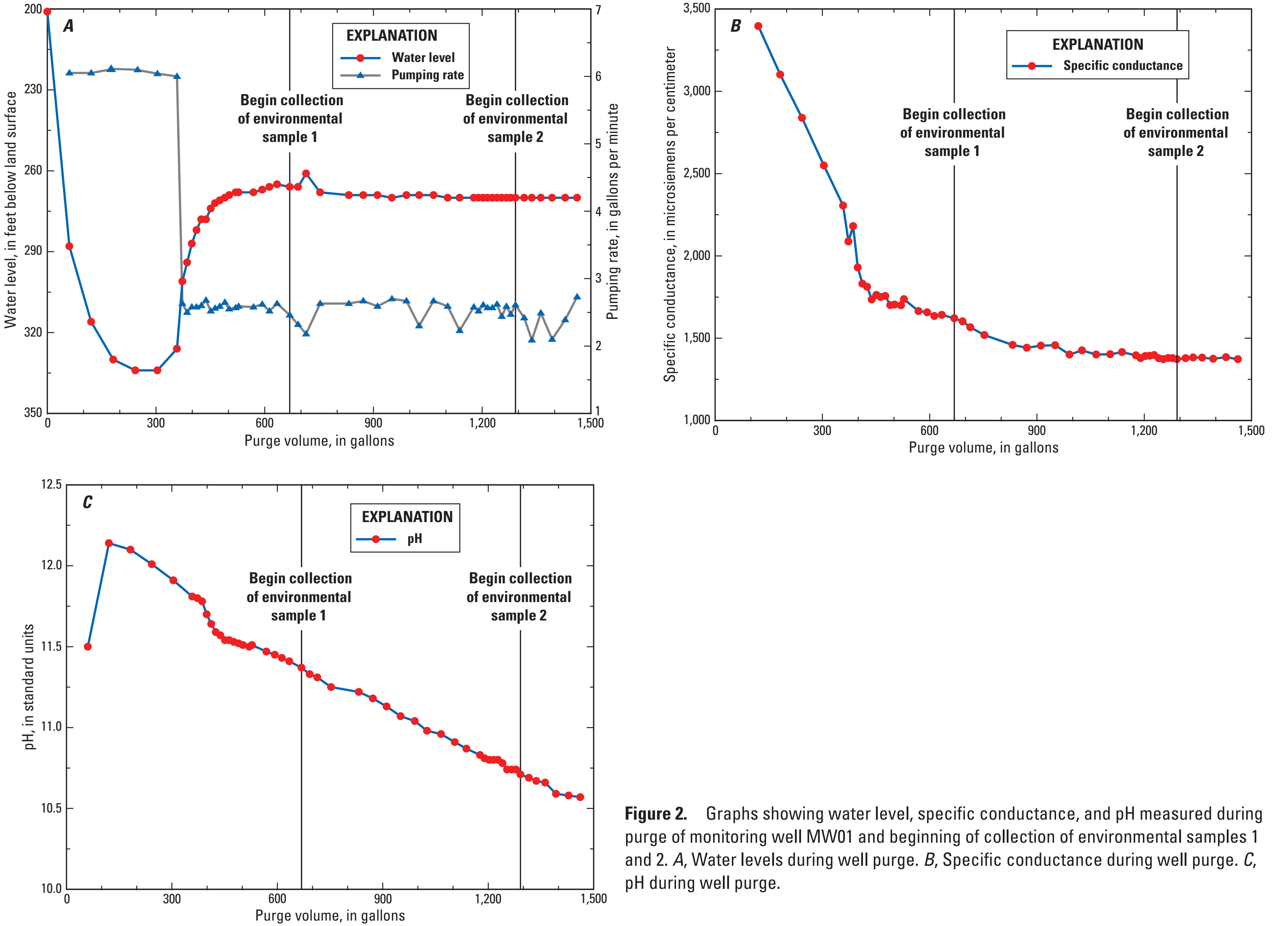


Figure 2. Graphs showing water level, specific conductance, and pH measured during purge of monitoring well MW01 and beginning of collection of environmental samples 1 and 2. *A*, Water levels during well purge. *B*, Specific conductance during well purge. *C*, pH during well purge.

Table 5. Field water-quality properties and inorganic constituents in environmental samples collected from monitoring well MW01 near Pavillion, Wyoming, April 2012.

[RPD, relative percent difference; µs/cm, microsiemens per centimeter; mg/L, milligrams per liter; $CaCO_3$, calcium carbonate; µg/L, micrograms per liter; pCi/L, picocuries per liter; N, value was not determined; --, not applicable]

Field water-quality property or inorganic constituent		Environmental sample 1				Sample 1 replicate					Environmental sample 2				Sample 2 replicate				
Name	Units	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	RPD	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	RPD
U.S. Geological Survey field measurements and analyses																			
Water temperature	degrees Celsius	--	15.0	--	--	--	N	--	--	--	--	14.9	--	--	--	N	--	--	--
Specific conductance at 25 degrees Celsius	µS/cm	--	1,640	--	--	--	N	--	--	--	--	1,380	--	--	--	N	--	--	--
pH	standard units	--	11.4	--	--	--	N	--	--	--	--	10.7	--	--	--	N	--	--	--
Dissolved oxygen	mg/L	<	0.2	--	--	--	N	--	--	--	<	0.2	--	--	--	N	--	--	--
Dissolved oxygen, low-range method	mg/L	--	0.19	--	--	--	N	--	--	--	--	0.11	--	--	--	N	--	--	--
Alkalinity (in filtered water)	mg/L $CaCO_3$	--	215	--	--	--	213	--	--	0.9	--	174	--	--	--	182	--	--	4.5
Hydroxide (in filtered water)	mg/L	--	10.6	--	--	E	12	--	--	12.4	--	3.7	--	--	--	4.3	--	--	15.0
Carbonate (in filtered water)	mg/L	E	101.0	--	--	E	98.0	--	--	3.0	--	76.3	--	--	--	81.1	--	--	6.1
Bicarbonate (in filtered water)	mg/L	E	19.1	--	--	E	19.0	--	--	0.5	--	44.1	--	--	--	42.3	--	--	4.2
Acid neutralizing capacity (in unfiltered water)	mg/L $CaCO_3$	--	199	--	--	--	194	--	--	2.5	--	N	--	--	--	N	--	--	--
Hydroxide (in unfiltered water)	mg/L	E	5.6	2	--	--	7.8	2	--	32.8	--	N	--	--	--	N	--	--	--
Carbonate (in unfiltered water)	mg/L	E	91.8	--	--	--	90.0	--	--	2.0	--	N	--	--	--	N	--	--	--
Bicarbonate (in unfiltered water)	mg/L	E	35.3	2	--	--	25.1	2	--	33.8	--	N	--	--	--	N	--	--	--
Ferrous iron	mg/L	--	0.02	--	--	--	N	--	--	--	--	0.04	--	--	--	N	--	--	--
TestAmerica Laboratories																			
Calcium (in filtered water)	µg/L	--	9,400	6	--	--	9,400	6	--	0.0	--	8,900	6	--	--	N	--	--	--
Calcium (in unfiltered water)	µg/L	--	9,000	6	--	--	9,000	6	--	0.0	--	8,800	6	--	--	N	--	--	--

Table 5. Field water-quality properties and inorganic constituents in environmental samples collected from monitoring well MW01 near Pavillion, Wyoming, April 2012.—Continued

[RPD, relative percent difference; µs/cm, microsiemens per centimeter; mg/L, milligrams per liter; $CaCO_3$, calcium carbonate; µg/L, micrograms per liter; pCi/L, picocuries per liter; N, value was not determined; --, not applicable]

Field water-quality property or inorganic constituent		Environmental sample 1				Sample 1 replicate					Environmental sample 2				Sample 2 replicate				
Name	Units	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	RPD	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	RPD
Magnesium (in filtered water)	µg/L	E	140	1	J	E	150	1, 6	J	6.9	E	170	1	J	--	N		--	--
Magnesium (in unfiltered water)	µg/L	E	140	--	J	E	140	6	J	0.0	E	180	--	J	--	N	--	--	--
Sodium (in filtered water)	µg/L	--	270,000	--	B	--	280,000	6	B	3.6	--	280,000	6	B	--	N	--	--	--
Sodium (in unfiltered water)	µg/L	--	270,000	--	--	--	270,000	6	--	0.0	--	270,000	6	--	--	N	--	--	--
Potassium (in filtered water)	µg/L	--	15,000	--	--	--	16,000	6	--	6.5	--	13,000	--	--	--	N	--	--	--
Potassium (in unfiltered water)	µg/L	--	15,000	--	--	--	15,000	6	--	0.0	--	13,000	--	--	--	N	--	--	--
Chloride (in filtered water)	mg/L	--	26	--	--	--	26	--	--	0.0	--	27	--	--	--	N	--	--	--
Sulfate (in filtered water)	mg/L	--	380	--	--	--	380	--	--	0.0	--	410	--	--	--	N	--	--	--
Bromide (in filtered water)	mg/L	E	0.2	--	J	E	0.2	--	J	0.0	E	0.2	--	J	--	N	--	--	--
Fluoride (in filtered water)	mg/L	--	3	--	--	--	3	--	--	3.3	--	3	--	--	--	N	--	--	--
Silicon (in filtered water)	µg/L	--	9,000	--	--	--	8,700	--	--	3.4	--	6,400	--	--	--	N	--	--	--
Silica (in unfiltered water)	µg/L	--	18,000	--	B	--	18,000	--	B	0.0	--	13,000	--	B	--	N	--	--	--
Dissolved solids (in filtered water)	mg/L	--	800	--	--	--	800	--	--	0.0	--	800	--	--	--	N	--	--	--
Ammonia as nitrogen (in unfiltered water)	mg/L	--	0.79	1, 3	B	E	0.71	1, 3	B	10.7	E	0.34	1, 3	B	--	N	--	--	--
Nitrate-plus-nitrite as nitrogen (in unfiltered water)	mg/L	<	0.019	--	--	<	0.019	--	--	--	<	0.02	--	--	--	N	--	--	--
Phosphorus (in filtered water)	µg/L	--	57	2, 3	--	--	89	2, 3	--	43.8	--	61	3	--	--	N	--	--	--
Phosphorus (in unfiltered water)	µg/L	--	100	1	B	--	98	1	B	2.0	--	84	1	B	--	N	--	--	--

Table 5. Field water-quality properties and inorganic constituents in environmental samples collected from monitoring well MW01 near Pavillion, Wyoming, April 2012.—Continued

[RPD, relative percent difference; µs/cm, microsiemens per centimeter; mg/L, milligrams per liter; $CaCO_3$, calcium carbonate; µg/L, micrograms per liter; pCi/L, picocuries per liter; N, value was not determined; --, not applicable]

Field water-quality property or inorganic constituent		Environmental sample 1				Sample 1 replicate					Environmental sample 2				Sample 2 replicate				
Name	Units	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	RPD	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	RPD
Dissolved organic carbon (in filtered water)	mg/L	--	4.3	6	--	--	4.4	6	--	2.3	--	3	6	--	--	N	--	--	--
Total organic carbon (in unfiltered water)	mg/L	--	4.0	6	--	--	4.1	6	--	2.5	--	2.9	6	--	--	N	--	--	--
Dissolved inorganic carbon (in filtered water)	mg/L	--	20	--	--	--	19	--	--	5.1	--	21	--	--	--	N	--	--	--
Total inorganic carbon (in unfiltered water)	mg/L	--	22	--	--	--	21	--	--	4.7	--	22	--	--	--	N	--	--	--
Aluminum (in filtered water)	µg/L	--	170	--	--	--	170	--	--	0.0	--	100	--	--	--	N	--	--	--
Aluminum (in unfiltered water)	µg/L	--	170	--	--	--	170	--	--	0.0	--	110	--	--	--	N	--	--	--
Antimony (in filtered water)	µg/L	<	0.4	--	--	E	0.54	1, 6	J, ^, B	--	<	0.4	--	--	--	N	--	--	--
Antimony (in unfiltered water)	µg/L	<	0.4	--	--	<	0.4	6	--	--	<	0.4	--	--	--	N	--	--	--
Arsenic (in filtered water)	µg/L	E	0.62	6	J	<	0.33	--	--	--	<	0.33	--	--	--	N	--	--	--
Arsenic (in unfiltered water)	µg/L	E	0.38	2, 6	J	E	0.51	2	J	29.2	E	0.48	--	J	--	N	--	--	--
Barium (in filtered water)	µg/L	--	23	6	--	--	20	--	--	14.0	--	21	--	--	--	N	--	--	--
Barium (in unfiltered water)	µg/L	--	19	6	--	--	20	--	--	5.1	--	21	--	--	--	N	--	--	--
Beryllium (in filtered water)	µg/L	<	0.08	--	--	<	0.08	--	--	--	<	0.08	--	--	--	N	--	--	--
Beryllium (in unfiltered water)	µg/L	<	0.08	--	--	<	0.08	--	--	--	<	0.08	--	--	--	N	--	--	--
Boron (in filtered water)	µg/L	--	130	--	--	--	130	6	--	0.0	--	120	6	--	--	N	--	--	--
Boron (in unfiltered water)	µg/L	--	130	--	--	--	120	6	--	8.0	--	110	6	--	--	N	--	--	--

Table 5. Field water-quality properties and inorganic constituents in environmental samples collected from monitoring well MW01 near Pavillion, Wyoming, April 2012.—Continued

[RPD, relative percent difference; µs/cm, microsiemens per centimeter; mg/L, milligrams per liter; $CaCO_3$, calcium carbonate; µg/L, micrograms per liter; pCi/L, picocuries per liter; N, value was not determined; --, not applicable]

Field water-quality property or inorganic constituent		Environmental sample 1				Sample 1 replicate					Environmental sample 2				Sample 2 replicate				
Name	Units	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	RPD	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	RPD
Cadmium (in filtered water)	µg/L	<	0.1	--	--	<	0.1	--	--	--	<	0.1	--	--	--	N	--	--	--
Cadmium (in unfiltered water)	µg/L	E	0.11	1	J	<	0.1	--	--	--	<	0.1	--	--	--	N	--	--	--
Chromium (in filtered water)	µg/L	<	0.5	--	--	<	0.5	--	--	--	<	0.5	--	--	--	N	--	--	--
Chromium (in unfiltered water)	µg/L	<	0.5	--	--	<	0.5	--	--	--	<	0.5	--	--	--	N	--	--	--
Cobalt (in filtered water)	µg/L	<	0.054	--	--	<	0.054	--	--	--	<	0.054	--	--	--	N	--	--	--
Cobalt (in unfiltered water)	µg/L	<	0.054	--	--	<	0.054	--	--	--	<	0.054	--	--	--	N	--	--	--
Copper (in filtered water)	µg/L	<	0.56	--	--	<	0.56	--	--	--	<	0.56	--	--	--	N	--	--	--
Copper (in unfiltered water)	µg/L	<	0.56	--	--	<	0.56	--	--	--	<	0.56	--	--	--	N	--	--	--
Iron (in filtered water)	µg/L	<	22	--	--	<	22	--	--	--	<	22	--	--	--	N	--	--	--
Iron (in unfiltered water)	µg/L	<	22	--	--	<	22	--	--	--	E	55	--	J ^	--	N	--	--	--
Lead (in filtered water)	µg/L	<	0.18	--	--	<	0.18	--	--	--	<	0.18	--	--	--	N	--	--	--
Lead (in unfiltered water)	µg/L	<	0.18	--	--	<	0.18	--	--	--	<	0.18	--	--	--	N	--	--	--
Lithium (in filtered water)	µg/L	--	44	--	--	--	45	6	--	2.2	--	33	--	--	--	N	--	--	--
Lithium (in unfiltered water)	µg/L	--	44	--	--	--	43	6	--	2.3	--	36	--	--	--	N	--	--	--
Manganese (in filtered water)	µg/L	<	0.31	--	--	--	1	6	--	--	E	0.42	--	J	--	N	--	--	--
Manganese (in unfiltered water)	µg/L	E	0.57	2	J	E	0.46	2, 6	J	21.4	E	0.80	--	J	--	N	--	--	--
Mercury (in filtered water)	µg/L	<	0.027	--	--	<	0.027	--	--	--	<	0.027	--	--	--	N	--	--	--
Mercury (in unfiltered water)	µg/L	<	0.027	--	--	<	0.027	--	--	--	<	0.027	--	--	--	N	--	--	--
Molybdenum (in filtered water)	µg/L	--	10	6	--	--	9.7	--	--	3.0	--	7.6	--	--	--	N	--	--	--

Table 5. Field water-quality properties and inorganic constituents in environmental samples collected from monitoring well MW01 near Pavillion, Wyoming, April 2012.—Continued

[RPD, relative percent difference; µs/cm, microsiemens per centimeter; mg/L, milligrams per liter; $CaCO_3$, calcium carbonate; µg/L, micrograms per liter; pCi/L, picocuries per liter; N, value was not determined; --, not applicable]

Field water-quality property or inorganic constituent		Environmental sample 1				Sample 1 replicate					Environmental sample 2				Sample 2 replicate				
Name	Units	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	RPD	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	RPD
Molybdenum (in unfiltered water)	µg/L	--	9.8	6	--	--	10	--	--	2.0	--	7.8	--	--	--	N	--	--	--
Nickel (in filtered water)	µg/L	<	0.3	--	--	<	0.3	--	--	--	<	0.3	--	--	--	N	--	--	--
Nickel (in unfiltered water)	µg/L	E	0.3	2	J	E	0.44	2	J	37.8	<	0.3	--	--	--	N	--	--	--
Selenium (in filtered water)	µg/L	<	0.7	--	--	<	0.7	--	--	--	<	0.7	--	--	--	N	--	--	--
Selenium (in unfiltered water)	µg/L	<	0.7	--	--	<	0.7	--	--	--	<	0.7	--	--	--	N	--	--	--
Silver (in filtered water)	µg/L	<	0.033	--	--	<	0.033	--	--	--	<	0.033	--	--	--	N	--	--	--
Silver (in unfiltered water)	µg/L	<	0.033	--	--	<	0.033	--	--	--	<	0.033	--	--	--	N	--	--	--
Strontium (in filtered water)	µg/L	--	300	--	--	--	310	6	--	3.3	--	280	--	--	--	N	--	--	--
Strontium (in unfiltered water)	µg/L	--	300	--	--	--	300	6	--	0.0	--	280	--	--	--	N	--	--	--
Thallium (in filtered water)	µg/L	<	0.05	--	--	<	0.05	--	--	--	<	0.05	--	--	--	N	--	--	--
Thallium (in unfiltered water)	µg/L	E	0.068	1	J	<	0.05	--	--	--	E	0.096	1	J	--	N	--	--	--
Titanium (in filtered water)	µg/L	<	0.6	--	--	<	0.6	--	--	--	<	0.6	--	--	--	N	--	--	--
Titanium (in unfiltered water)	µg/L	<	0.6	--	--	<	0.6	--	--	--	E	0.69	--	J	--	N	--	--	--
Uranium (in filtered water)	µg/L	<	0.05	--	--	<	0.05	--	--	--	<	0.05	--	--	--	N	--	--	--
Uranium (in unfiltered water)	µg/L	E	0.14	1	J	<	0.05	--	--	--	E	0.14	1	J	--	N	--	--	--
Vanadium (in filtered water)	µg/L	E	0.6	6	J	<	0.5	--	--	--	<	0.5	--	--	--	N	--	--	--
Vanadium (in unfiltered water)	µg/L	<	0.5	6	--	<	0.5	--	--	--	E	0.53	--	J	--	N	--	--	--
Zinc (in filtered water)	µg/L	<	2	--	^	<	2	--	^	--	<	2	--	^	--	N	--	--	--
Zinc (in unfiltered water)	µg/L	<	2	--	--	<	2	--	--	--	<	2	--	--	--	N	--	--	--

Table 5. Field water-quality properties and inorganic constituents in environmental samples collected from monitoring well MW01 near Pavillion, Wyoming, April 2012.—Continued

[RPD, relative percent difference; µs/cm, microsiemens per centimeter; mg/L, milligrams per liter; $CaCO_3$, calcium carbonate; µg/L, micrograms per liter; pCi/L, picocuries per liter; N, value was not determined; --, not applicable]

Field water-quality property or inorganic constituent		Environmental sample 1				Sample 1 replicate					Environmental sample 2				Sample 2 replicate				
Name	Units	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	RPD	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	RPD
Eberline Laboratory																			
Radium-226 (in filtered water) with radon method	pCi/L	--	0.087	--	--	--	N	--	--	--	--	0.100	--	--	--	N	--	--	--
Radium-228 (in filtered water)	pCi/L	R	0.16	--	--	--	N	--	--	--	--	0.23	--	--	--	N	--	--	--
U.S. Geological Survey National Water Quality Laboratory																			
Radon-222 (in unfiltered water)	pCi/L	--	1,060	--	--	--	N	--	--	--	--	N	--	--	--	N	--	--	--

[1]Remarks used in table:

<, less than.

E, less than the reporting level, but equal to or greater than the method detection limit.

R, value below sample-specific critical level.

[2]Project data qualifiers used in table:

1 - Quantified concentration in the environmental sample is less than five times the maximum concentration in a blank sample.

2 - Relative percent difference (RPD) between the environmental sample and replicate sample was greater than 20 percent.

3 - Potential low bias; recovery was less than 70 percent in one or more spike samples.

4 - Potential high bias; recovery was greater than 130 percent in one or more spike samples (only applied to constituents with quantified results).

5 - Value is mean of two results reported by the laboratory.

6 - Filtered value exceeds unfiltered value.

[3]Laboratory data qualifiers used in table:

^ - Instrument related quality control exceeds the control limits.

4 - The analyte present in the environmental sample is four times greater than the matrix spike concentration; therefore, control limits are not applicable.

E - Result exceeded calibration range.

F - Recovery in the matrix spike or matrix-spike duplicate exceeds the control limits.

B - Detected compound was also found in the laboratory blank.

J - Result is less than the reporting limit but greater than or equal to the method detection limit, and the concentration is an approximate value.

Table 6. Inorganic constituents in quality-control samples collected for monitoring well MW01 near Pavillion, Wyoming, April 2012. (Excel file)

Organic Constituents

Concentrations of organic constituents included in analysis of the environmental samples and sample replicates collected from well MW01 are listed in table 7. Blank and spike sample analytical results are listed in table 8. Acrylonitrile was the only VOC detected, and that compound was detected only in the sample 1 replicate. Acrylonitrile is a component of nitrile gloves, which were worn during sample collection and processing. Nitrile gloves also were used by TestAmerica Laboratories (TestAmerica Laboratories, oral commun., 2012). VOCs could go undetected in an environmental sample if the analytical method used to measure them has poor recovery for those compounds. Of the 80 VOCs that were analyzed, only 1,1,2,2-tetrachloroethane, carbon disulfide, and isopropanol had spike recoveries less than 70 percent for any spiked sample.

Four semivolatile organic compounds (SVOCs)—3- and 4-methylphenol, benzoic acid, benzyl alcohol, and phenol—were detected in environmental samples; however, the concentration for benzyl alcohol (table 7) was less than five times the maximum concentration detected in associated laboratory and field blank samples (table 8). Benzoic acid was detected in all the environmental samples; however, spike recoveries for this compound were greater than 130 percent (table 8), indicating these concentrations might be biased high. Reported concentrations for several SVOCs include an “E” remark (table 7) because they are less than the reporting level, but equal to or greater than the method detection limit. Five of the SVOCs (2,4-dimethylphenol, 3,3’-dichlorobenzidine, aniline, hexachlorocyclopentadiene, and hexachloroethane) that were not detected in environmental samples had spike recoveries less than 70 percent (table 8). For example, the recovery for hexachlorocyclopentadiene was as low as 12 percent.

Analytical results from methods used to analyze VOCs and SVOCs included tentatively identified compounds (TICs), which are not part of the standard suite of reported analytes. TIC analyses provide a qualitative measure of the presence of compounds, but require additional analytical testing to confirm. Concentrations of TICs included in analysis of the environmental samples and QC samples (replicates and blanks) collected from well MW01 are listed in appendix 7. Thirty VOC TICs and three SVOC TICs were quantified in various environmental samples and blanks. One of these compounds (cyclotetrasiloxane, octamethyl-) was identified only in a laboratory blank; one other compound (silanol, trimethyl-) was identified in a single environmental sample, but also in two blanks at similar concentrations, indicating potential contamination bias. Eight compounds were identified in all environmental samples, both preserved and unpreserved. Concentrations of these were similar within each sample set (environmental sample and replicate), but were different between the two samples (1 and 2). Concentrations of propane in the TIC analyses were less than one-half the concentrations reported by TestAmerica Laboratories for dissolved gas analysis (table 9). One compound of interest in the Pavillion area, 2-butoxyethanol, was not identified in the TIC analyses of any of the environmental samples.

Table 7. Organic constituents in environmental samples collected from monitoring well MW01 near Pavillion, Wyoming, April 2012. (Excel file)

Table 8. Organic constituents in quality-control samples collected for monitoring well MW01 near Pavillion, Wyoming, April 2012. (Excel file)

Concentrations for several other classes of organic compounds (tables 7 and 8) also included an “E” remark (less than the reporting level, but equal to or greater than the method detection limit). Diesel-range organics and gasoline-range organics were detected in all environmental samples and associated replicates, although all the concentrations for diesel-range organics (DRO) included an “E” remark. Twelve polycyclic aromatic hydrocarbons (PAHs) were detected in the environmental samples and associated replicates, but the maximum concentrations for 10 of these PAHs were less than five times the maximum concentration detected in associated laboratory and field blanks. All reported PAH concentrations included an “E” remark. No glycols were detected in any samples. Spike recoveries for glycols ranged from 93 to 106 percent, and method detection limits ranged from 7.73 to 18.70 milligrams per liter (mg/L). Methylene blue active substances were detected in the environmental samples, but all reported concentrations included an “E” remark and are less than five times the maximum concentration detected in the field blank.

Dissolved Gasses

Dissolved gasses measured in environmental samples and QC samples (replicates) collected from well MW01 are listed in table 9. Blank and spike sample analytical results are listed in table 10. Several different hydrocarbon gasses, including methane, ethane, propane, and several higher molecular weight compounds, were detected in the groundwater-quality samples. Many of the gasses (including argon, carbon dioxide, ethane, ethylene, methane, nitrogen, oxygen, and propane) were analyzed by more than one laboratory; using different analytical methods. For example, methane was analyzed by TestAmerica Laboratories, Isotech Laboratories, Inc., and the USGS Chlorofluorocarbon Laboratory. Because of the laboratory overlap of analyses of several dissolved gasses, a short description of the differences in gas concentrations between laboratories follows.

Methane concentrations reported by TestAmerica Laboratories and the USGS Reston Chlorofluorocarbon Laboratory are similar (table 9). For example, TestAmerica reported

Table 9. Dissolved gasses in environmental samples collected from monitoring well MW01 near Pavillion, Wyoming, April 2012.

[All constituents analyzed in unfiltered water. RPD, relative percent difference; µg/L, micrograms per liter; mg/L, milligrams per liter; --, not applicable; N, value was not determined]

Dissolved Gas			Preservative added to bottle	Environmental sample 1				Sample 1 replicate					Environmental sample 2				Sample 2 replicate				
Name	Alternative name	Units		Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers	RPD	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers	RPD
TestAmerica Laboratories																					
Methane	--	µg/L	Yes	--	27,500	5	--	--	30,500	5	--	10.3	--	25,500	5	--	--	27,000	5	--	5.7
Methane	--	µg/L	No	--	27,000	5	--	--	27,000	5	--	0.0	--	20,000	5	--	--	22,000	5	--	9.5
Ethane	--	µg/L	Yes	--	3,600	4	--	--	4,000	4	--	10.5	--	3,200	4	--	--	3,300	4	--	3.1
Ethane	--	µg/L	No	--	3,800	4	--	--	3,800	4	--	0.0	--	2,600	4	--	--	2,800	4	--	7.4
Ethylene	--	µg/L	Yes	<	7.2	5	--	<	7.2	5	--	--	<	7.2	5	--	<	7.2	5	--	--
Ethylene	--	µg/L	No	<	7.2	5	--	<	7.2	5	--	--	<	7.2	5	--	<	7.2	5	--	--
Propane	--	µg/L	Yes	--	1,400	--	--	--	1,300	--	--	7.4	--	1,100	--	--	--	1,000	--	--	9.5
Propane	--	µg/L	No	--	1,300	--	--	--	1,100	--	--	16.7	--	1,000	--	--	--	970	--	--	3.0
Isotech Laboratories, Inc.																					
Argon	--	mole percent	Yes	--	N	--	--	--	N	--	--	--	--	0.446	--	--	--	N	--	--	--
Carbon monoxide	--	mole percent	Yes	--	N	--	--	--	N	--	--	--	U	--	--	--	--	N	--	--	--
Carbon dioxide	--	mole percent	Yes	--	N	--	--	--	N	--	--	--	U	--	--	--	--	N	--	--	--
Hydrogen	--	mole percent	Yes	--	N	--	--	--	N	--	--	--	U	--	--	--	--	N	--	--	--
Oxygen	--	mole percent	Yes	--	N	--	--	--	N	--	--	--	--	0.078	--	--	--	N	--	--	--
Nitrogen	--	mole percent	Yes	--	N	--	--	--	N	--	--	--	--	20.40	--	--	--	N	--	--	--
Methane	--	mole percent	Yes	--	N	--	--	--	N	--	--	--	--	73.44	--	--	--	N	--	--	--
Ethane	--	mole percent	Yes	--	N	--	--	--	N	--	--	--	--	4.18	--	--	--	N	--	--	--
Ethylene	--	mole percent	Yes	--	N	--	--	--	N	--	--	--	--	0.001	--	--	--	N	--	--	--
Propane	--	mole percent	Yes	--	N	--	--	--	N	--	--	--	--	0.913	--	--	--	N	--	--	--
Propylene	--	mole percent	Yes	--	N	--	--	--	N	--	--	--	--	0.001	--	--	--	N	--	--	--
n-Butane	--	mole percent	Yes	--	N	--	--	--	N	--	--	--	--	0.178	--	--	--	N	--	--	--
Iso-butane	2-Methyl-propane	mole percent	Yes	--	N	--	--	--	N	--	--	--	--	0.213	--	--	--	N	--	--	--
n-Pentane	--	mole percent	Yes	--	N	--	--	--	N	--	--	--	--	0.030	--	--	--	N	--	--	--
Iso-pentane	2-Methyl-butane	mole percent	Yes	--	N	--	--	--	N	--	--	--	--	0.066	--	--	--	N	--	--	--

Table 9. Dissolved gasses in environmental samples collected from monitoring well MW01 near Pavillion, Wyoming, April 2012.—Continued

[All constituents analyzed in unfiltered water. RPD, relative percent difference; µg/L, micrograms per liter; mg/L, milligrams per liter; --, not applicable; N, value was not determined]

Dissolved Gas			Preservative added to bottle	Environmental sample 1				Sample 1 replicate					Environmental sample 2				Sample 2 replicate				
Name	Alternative name	Units		Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers	RPD	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers	RPD
Hexanes plus	--	mole percent	Yes	--	N	--	--	--	N	--	--	--	--	0.053	--	--	--	N	--	--	--
U.S. Geological Survey Reston Chlorofluorocarbon Laboratory																					
Argon	--	mg/L	No	--	0.183	5	--	--	0.186	5	--	1.3	--	0.305	5	--	--	N	--	--	--
Carbon dioxide	--	mg/L	No	--	129.1	5	--	--	125.0	5	--	3.2	--	121.1	5	--	--	N	--	--	--
Oxygen	--	mg/L	No	--	0.1	5	--	--	0.1	5	--	0.0	--	0.1	5	--	--	N	--	--	--
Methane	--	mg/L	No	--	26	5	--	--	26	5	--	1.6	--	28	5	--	--	N	--	--	--
Nitrogen	--	mg/L	No	--	3.86	5	--	--	4.01	5	--	3.8	--	7.95	5	--	--	N	--	--	--

[1]Remarks used in table:

<, less than.

U, analyzed for but not detected.

[2]Project data qualifiers used in table:

1 - Quantified concentration in the environmental sample is less than five times the maximum concentration in a blank sample.

2 - Relative percent difference (RPD) between the environmental sample and replicate is greater than 20 percent.

3 - Potential low bias; recovery is less than 70 percent in one or more spike samples.

4 - Potential high bias; recovery is greater than 130 percent in one or more spike samples (only applied to constituents with quantified results).

5 - Value is mean of two results reported by the laboratory.

6 - Filtered value exceeds unfiltered value.

methane concentrations ranging from 20 to 30.5 mg/L (or 20,000 to 30,500 micrograms per liter) for environmental sample 1 and the sample 1 replicate, and the USGS Reston Chlorofluorocarbon Laboratory reported methane concentrations ranging from 26 to 28 mg/L.

Carbon dioxide concentrations reported by Isotech Laboratories, Inc., and the USGS Reston Chlorofluorocarbon Laboratory are not similar. Isotech Laboratories, Inc., did not detect carbon dioxide in environmental sample 2, whereas the USGS Reston Chlorofluorocarbon Laboratory reported carbon dioxide concentrations in environmental sample 2 greater than 100 mg/L. This difference may be due to different methods for stripping gas from solution before the analysis. Isotech Laboratories, Inc., and the USGS Reston Chlorofluorocarbon Laboratory reported very small concentrations of dissolved oxygen in the samples, which is in agreement with the field measurements (table 5).

A full suite of QC samples (replicates; laboratory, source solution, trip, ambient and field blanks; and reagent and matrix spikes) were collected and analyzed for dissolved gas samples sent to TestAmerica Laboratories (table 10). Dissolved gasses were not detected in any of the blank samples. Recoveries of dissolved gasses in the reagent spikes ranged from 89 to 95 percent. Recoveries in the matrix spikes were much more variable ranging from -33 to 1,004 percent; this large variability likely is due to the dissolved gasses present at concentrations at least four times greater than the matrix spike concentration. In these cases, recovery-control limits likely are not applicable.

Two dissolved gas samples (environmental sample 1 and environmental sample 2) were sent to Isotech Laboratories, Inc., for analysis. The container for environmental sample 1 was cracked, and therefore, was not analyzed. Environmental sample 2 was analyzed for 16 dissolved gasses; 13 gasses were detected (table 9). These data have no qualifiers because no QC samples were sent to Isotech Laboratories, Inc., for analysis.

Table 10. Dissolved gasses in quality-control samples collected for monitoring well MW01 near Pavillion, Wyoming, April 2012. (Excel file)

Isotopes and Environmental Tracers

Isotopic values and concentrations of environmental tracers in environmental samples collected from well MW01 are listed in table 11. Stable isotopic data are provided for methane (hydrogen and carbon), water (hydrogen and oxygen), and dissolved inorganic carbon (carbon). Groundwater-quality samples also were analyzed for environmental tracers, including carbon-14 of dissolved inorganic carbon, the chlorofluorocarbons CFC-11, CFC-12, and CFC-113; SF_6; tritium; the noble gasses helium, neon, argon, krypton, and xenon; and δ^3He. Analytical results for tritium, neon, krypton, xenon, and δ^3He had not been reported by the laboratories as of August 17, 2012, but analytical results will be entered in the USGS NWIS database when available and will be accessible through the USGS NWIS Web Interface at *http://waterdata.usgs.gov/wy/nwis/qw*. Many of these environmental tracers can be used to determine the presence of young or modern water or the apparent age of groundwater (Dunkle and others, 1993; Ekwurzel and others, 1994; Busenberg and Plummer, 2000; Plummer and others, 2004; McMahon and others, 2011).

Quality-Control Results for Monitoring Well MW01

The implications of QC results for the environmental sample results from monitoring well MW01 can be summarized from project data qualifiers listed in tables 5, 7, 9, and 11. Laboratory analytical results were reported for 234 constituents in various samples. Results were less than method detection limits in all blank samples for 215 (92 percent) of those constituents. There were 1,194 total analytical results for those 234 constituents in the 2 environmental samples and 2 replicate samples. Forty-three results (3.6 percent) were qualified because they were less than 5 times the maximum concentration in associated blanks. Concentrations for replicate samples were reported for 244 constituents in 570 environmental-sample/replicate pairs. Variability was within 20 percent for 559 (98 percent) of those pairs. One result each for 11 constituents was qualified because replicate variability exceeded the 20-percent criterion. Recoveries for spike samples were available for 210 constituents. Recoveries were within 70–130 percent for 195 (93 percent) of those constituents. Of the 1,050 results for those 210 constituents in the 2 environmental samples and 2 replicates, 42 results (4 percent) were qualified because of low recovery and 16 results (1.5 percent) were qualified because of high recovery. Overall, 646 analytical results were available for constituents with some type of QC data for the 2 primary environmental samples. Sixty-one of these results (9.4 percent) were qualified because of potential blank contamination, high variability, high recovery, or low recovery.

Quality-Control Results for Monitoring Well MW02

Groundwater-quality samples were not collected from monitoring well MW02. The USGS redeveloped well MW02 during the week of April 30, 2012. Two QC samples were collected during redevelopment.

The QC samples were analyzed for several inorganic and organic constituents and dissolved gasses (table 3). Analytical results for both QC samples are listed in tables 12, 13, and 14. Analytical results from these two samples are not described further in this report because well MW02 was not sampled.

Table 11. Isotopes and environmental tracers in environmental samples collected from monitoring well MW01 near Pavillion, Wyoming, April 2012.

[All constituents analyzed in unfiltered water except δ13C of dissolved inorganic carbon and carbon-14 of dissolved inorganic carbon, which were filtered using a 0.45-micron capsule filter. RPD, relative percent difference; δ13C, ratio of carbon-13 to carbon-12 isotopes in the sample relative to the ratio in a reference standard; per mil, parts per thousand; VPDB, Vienna PeeDee Belemnite; δ2H, ratio of hydrogen-2 to hydrogen-1 isotopes in the sample relative to the ratio in a reference standard; VSMOW, Vienna Standard Mean Ocean Water; CFC, chlorofluorocarbon; --, not applicable; N, value was not determined]

Analyte	Units	Environmental sample 1				Sample 1 replicate					Environmental sample 2			
		Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers[3]	RPD	Remark[1]	Value	Project data qualifiers[2]	Laboratory data qualifiers
Isotech Laboratories, Inc.														
δ13C of methane	per mil, relative to VPDB	--	N	--		--	--	--	--	--	--	–38.54	--	--
δ2H of methane	per mil, relative to VSMOW	--	N	--		--	--	--	--	--	--	–208.0	--	--
U.S. Geological Survey Reston Chlorofluorocarbon Laboratory														
CFC-11	picogram per kilogram	--	2	--	--	--	--	--	--	--	--	N	--	--
CFC-113	picogram per kilogram	U	--	--	--	--	--	--	--	--	--	N	--	--
CFC-12	picogram per kilogram	--	13	--	--	--	--	--	--	--	--	N	--	--
Helium	10-9 cubic centimeters of helium per gram of water at standard temperature and pressure	--	1,170	5	--	--	1,190	5	--	0.8	--	2,940	--	--
Sulfur hexafluoride (SF6)	femtogram per kilogram	<	1.00	--	--	--	--	--	--	--	<	1.00	--	--
U.S. Geological Survey Reston Stable Isotope Laboratory														
δ18O of water	per mil, relative to VSMOW	--	–13.32	--	--	--	–13.38	--	--	–0.4	--	–13.39	--	--
δ2H of water	per mil, relative to VSMOW	--	–113	--	--	--	–113	--	--	0.0	--	–113	--	--
Woods Hole Oceanographic Institute														
δ13C of dissolved inorganic carbon	per mil, relative to VPDB	--	–14.39	--	--	--	--	--	--	--	--	–14.11	--	--
Carbon-14 of dissolved inorganic carbon	percent carbon, normalized	--	2.22	--	--	--	--	--	--	--	--	1.53	--	--
U.S. Geological Survey Menlo Park Tritium Laboratory														
Tritium in water	picocuries per liter	--	0.60	--	--	<	0.2	--	R	--	--	0.30	--	--

[1]Remarks used in table:
<, less than.
U, analyzed for but not detected.

[2]Project data qualifiers used in table.
1 - Quantified concentration in the environmental sample is less than five times the maximum concentration in a blank sample.
2 - Relative percent difference (RPD) between the environmental sample and replicate is greater than 20 percent.
3 - Potential low bias; recovery is less than 70 percent in one or more spike samples.
4 - Potential high bias; recovery is greater than 130 percent in one or more spike samples (only applied to constituents with quantified results).
5 - Value is mean of two results reported by the laboratory.
6 - Filtered value exceeds unfiltered value.

[3]Laboratory data qualifiers used in table.
R - radchem non-detect, below sample specific critical level.

Table 12. Inorganic constituents in quality-control samples collected for monitoring well MW02 near Pavillion, Wyoming, May 2012. (Excel file)

Table 13. Organic constituents in quality-control samples collected for monitoring well MW02 near Pavillion, Wyoming, May 2012. (Excel file)

Table 14. Dissolved gasses in quality-control samples collected for monitoring well MW02 near Pavillion, Wyoming, May 2012. (Excel file)

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Appendix 1. Monitoring Well MW01 field notes—Field instrument calibration notes, general project notes, groundwater-quality notes for samples 1 and 2, alkalinity/acid-neutralizing capacity titration field notes and results (figures 1.1.1–1.3.2)

This appendix contains copies of field related project notes collected for activities related to monitoring well MW01. Specifically this appendix contains field instrument calibration notes (figures 1.1.1 and 1.1.2), general project notes (figures 1.2.1 through 1.2.12), groundwater-quality notes for Monitoring Well MW01 environmental sample 1 (figures 1.2.13 through 1.2.15, 1.2.21), the purge log for Monitoring Well MW01 samples 1 and 2 (figures 1.2.16 through 1.2.20), a list of analytes collected from Monitoring Well MW01 during sample 1 (figures 1.2.22 through 1.2.24), groundwater-quality notes for Monitoring Well MW01 environmental sample 2 (figures 1.2.25 through 1.2.27), field analysis notes for alkalinity, acid-neutralization capacity and miscellaneous measurements for Monitoring Well MW01 samples 1 and 2 (figures 1.3.1 through 1.3.9), and alkalinity and acid-neutralization capacity results for Monitoring Well MW01 samples 1 and 2 (figures 1.4.1 through 1.4.6).

Appendix 2. Monitoring Well MW01 laboratory-related documents—Analytical Services Request forms, Chain of Custody records (figures 2.1.1–2.9.7)

This appendix contains copies of laboratory analytical request forms (ASRs) and chain-of-custody forms (CoC), which accompanied environmental and quality-control samples during shipment to respective laboratories. This appendix includes ASR/CoC forms for the source solution (figures 2.1.1 through 2.1.3); ambient (figures 2.2.1 through 2.2.4) and field blanks (figures 2.3.1 through 2.3.5); ASR and COC forms for environmental sample 1 (figures 2.4.1 through 2.4.8, 2.4.10, and 2.4.17); the sample 1 replicate (2.5.1 through 2.5.5); environmental sample 2 (figures 2.6.1 through 2.6.7); the sample 2 replicate (2.7.1 through 2.7.4); the matrix spike sample (figures 2.8.1 through 2.8.5); the matrix-spike duplicate sample (figures 2.9.1 through 2.9.5); and the trip blank (2.9.6 and 2.9.7). Chain-of-custody records that relate to both samples 1 and 2 are included as figures 2.4.9 and 2.4.11 through 2.4.16.

Appendix 3. Monitoring Well MW01 photographs (figures 3.1–3.1.6)

This appendix contains a selection of photographs taken April 24, 2012, to document sampling activities at Monitoring Well MW01.

Appendix 4. Monitoring Well MW02 field notes—Groundwater-quality and field notes for collection of samples related to work at this well (figures 4.1–4.7)

This appendix contains copies of field related project notes collected for activities related to monitoring well MW02. Specifically, this appendix includes project notes (figure 4.1), groundwater- quality notes for the collection of a sample of public water supply of the city of Riverton, Wyoming (figures 4.2 through 4.6), and field notes for the collection of a downhole camera equipment blank (figure 4.7).

Appendix 5. Monitoring Well MW02 laboratory-related documents—Analytical Services Request forms, Chain of Custody records (figures 5.1.1–5.2.4)

This appendix contains copies of laboratory analytical request forms (ASRs) and chain-of-custody forms (CoC) that accompanied the sample of public water supply of the city of Riverton, Wyoming (figures 5.1.1 through 5.1.5) and the downhole camera blank (figures 5.2.1 through 5.2.4) to TestAmerica Laboratories.

Appendix 6. Monitoring Well MW02 photographs (figures 6.1–6.6)

This appendix contains a selection of photographs taken May 1st and 2nd, 2012 to document redevelopment related activities at Monitoring Well MW02.

Appendix 7. Tentatively identified compounds identified in environmental and quality-control samples collected for monitoring well MW01 near Pavillion, Wyoming

USGS

Wright and others—**Groundwater-Quality and Quality-Control Data for Two Monitoring Wells near Pavillion, Wyoming, April and May 2012**—Data Series 718

TECHNICAL MEMORANDUM

September 30, 2012

Prepared by:

Tom Myers, Ph.D.,
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Re: Assessment of Groundwater Sampling Results Completed by the U.S. Geological Survey

Summary

The organic chemistry at MW01 has not changed substantially since the EPA sampled the well; some constituents have increased and some have decreased, as would be expected with organic contaminants discharging from a series of event, the hydraulic fracturing of natural gas wells. Because the water chemistry data at MW01 has essentially been replicated, the evidence supporting the hypothesis that natural gas drilling activities, including fracking, have contaminated the Wind River aquifer near Pavillion WY has been strengthened. The conclusions based on that analysis should be more widely accepted now that the water quality has been replicated.

The concentrations of gas, including methane and ethane, have increased and that of propane has remained relatively constant. The ratio of ethane and propane to methane and the isotopic signature of methane all indicate that the gas source is thermogenic, meaning a deep formation. An increasing concentration indicates the formation is likely the source because the concentration will increase as more of the formation contributes to gas at the monitoring well.

EPA monitoring well 2 was not sampled because it did not yield sufficient water. The EPA had been able to purge over a borehole's volume of water, therefore they were clearly sampling formation water. There is no reason to consider that the current condition of MW02 negates the results of the EPA in 2011.

The problems with MW02 however indicate other problems with the sampling of these wells. The USGS used standard purge techniques, not techniques designed to minimize losses of volatile organics to the atmosphere. Purging too fast or drawing the water level too low could cause the measurement to be biased too low.

Introduction

The U.S. Environmental Protection Agency (EPA) published in late 2011 a study assessing the association of various organic compounds, which could be associated with the presence of natural gas development, or hydraulic fracturing (fracking), in water wells and monitoring wells near Pavillion WY. This study was one of the first to document fracking fluid chemicals in water wells and monitor wells away from the actual natural gas wells. The U.S. Geological Survey (USGS) recently published a data-series report (Wright et al 2012) that reports groundwater quality sampling completed in one of EPA's monitoring wells that had been constructed and sampled for the EPA study.

Wright et al (2012) do not make any conclusions regarding the data presented nor do they compare it to the original EPA report (EPA 2011). They present sampling and quality control data in detail. This memorandum takes the USGS study an additional step by comparing the results released in the new study with the original EPA report (EPA 2011). It considers whether the new data refutes the original EPA study, either with the actual chemistry data collected or by showing problems with EPA monitoring well 2.

Sampling and Chemistry of EPA Monitoring Well 1

USGS sampled EPA monitoring well # 1 (MW01) in late April 2012. The USGS collected four types of blank samples and two replicates from the well after purging more than a borehole's volume of water. Spike samples were also created to assess the accuracy of the testing equipment at the labs. EPA monitoring well # 2 (MW02) was not similarly sampled for reasons discussed in a following section.

Sampling commenced by purging groundwater from the well to remove the static water from the borehole. Their goal had been to remove at least one borehole volume, or 429 gallons, or to the point where several parameters including pH and EC stabilized. The USGS began pumping about 6 gpm which lowered the water level about 135 feet within the time that 300 gallons were removed from the well bore. At that point, the pumping rate dropped to about 2.5 gpm and the water level quickly recovered about 60 feet. Sampling commenced at about 670 cumulative gallons. Purging continued, and the second environmental sample commenced after about 1300 cumulative gallons. Thus the samples were taken after about one and half and three bore holes volume, respectively. The purge rate was commensurate with that used by the EPA for MW01 in that they started at 7.3 gpm and reduced it to about 6 gpm as the water level quickly dropped (EPA 2011).

The USGS did not sample exactly the same constituents as did the EPA. The USGS sampled many constituents and their Table 7 lists many that had below detect (ND) levels, as did the EPA. Table 1 compares constituents found by either the EPA (2011) or the USGS (Wright et al 2012), or by both.

Table 1: Comparison of water chemistry for EPA Monitoring Well # 1 for EPA phase 3 and 4 sampling (EPA 2011) with environmental samples 1 and 2 as reported by Wright et al (2012). The table includes only constituents for which there were detectable values at least once. Nd means no detect. Blank table cells under Phase 3 or 4 mean no sample. P means preservative added.

Name	Units	Phase 3	Phase 4	Env Sample 1	Env Sample 2
pH		11.9	11.2	11.4	10.7
K	mg/l	54.9	24.7	15	13
Cl	mg/l	23.3	23.1	26	27
Diesel-range organics [C10–C28]	µg/L	634	924	180	85
Gasoline-range organics [C6–C10]	µg/L	389	592	700	730
Gasoline-range organics [C6–C10]	µg/L			1100p	700p
3 & 4 Methylphenol	µg/L	included in phenol		0.95	0.47
Benzoic acid	µg/L	212	457	340	190
Benzyl alcohol	µg/L			0.59	nd
Phenol	µg/L	11.1	20.9	10	6.1
1-Methylnaphthalene	µg/L			0.0096	nd
2-Methylnaphthalene	µg/L			0.0110	0.0072
Benzo[*a*]anthracene	µg/L			nd	0.0042
Benzo[*a*]pyrene	µg/L			nd	0.0410
Benzo[*b*]fluoranthene	µg/L			nd	0.0310
Benzo[*g,h,i*]perylene	µg/L			0.0410	0.0740
Benzo[*k*]fluoranthene	µg/L			nd	0.0290
Chrysene	µg/L			nd	0.0037
Dibenz(*a,h*)anthracene	µg/L			nd	0.0510
Fluoranthene	µg/L			nd	0.0063
Indeno[1,2,3-*cd*]pyrene	µg/L			0.0160	0.0570
Pyrene	µg/L			0.0089	0.0130
Methylene blue active substances	mg/L			0.14	0.15
Methane	µg/L	15950	17930	27,500	25,500
Methane	µg/L			27,000p	20,000p
Ethane	µg/L	2230	2950	3,600	3,200
Ethane	µg/L			3,800p	2,600p
Ethylene	µg/L			7.2	7.2
Ethylene	µg/L			7.2p	7.2p

Propane	µg/L	790	1250	1,400	1,100
Propane	µg/L			1,300p	1,000p
Toluene	µg/L	0.75	0.56	nd	nd
xylenes (total)	µg/L		0.89	nd	nd
isopropanol	µg/L		212	nd	nd
diethylene glycol	µg/L		226	nd	nd
triethylene glycol	µg/L		46	nd	nd
tetraethylene glycol	µg/L		7.3	nd	nd
2-butoxyethanol	µg/L		12.7	not tested	
acetate	µg/L		8050	not tested	
formate	µg/L		112	not tested	
lactate	µg/L		69	not tested	
propionate	µg/L		309	not tested	

The concentrations of potassium (K) and the pH level are still much higher than the background levels in the formation, although K has decreased since the EPA sampling. EPA linked the presence of potassium to its use as a crosslinker and solvent during fracking, according to the Material Data Safety Sheets provided by the industry. Most of the fracking occurred several years ago, therefore the source is not a continuous release. A relatively conservative element such as potassium could move through the aquifer much more quickly than some of the organics.

Gasoline range organics and the various carbon-chain gases were found at concentrations that have increased significantly since the EPA study. Benzoic acid was found at concentrations similar to the EPA (2011). Diesel range organics and phenol remained present but at lower concentrations. The USGS found at least nine organic constituents that the EPA had either not found or not tested for. USGS found acrylonitrile at 21 ug/l in one of the replicate samples, not presented in Table 1[1]. At least six constituents that had been detected by the EPA (2011) were not detected by the USGS. At least six constituents that EPA has found at various concentrations were not tested for by the USGS.

The concentration of organics at Pavillion should vary for several reasons. Changes from one sampling event to the next do not represent a trend. A non-detect does not prove the constituent does not exist.

Organics are measured at very low concentrations, parts per billion, so a relatively small change proportionally seems much larger. An acceptable spike sample is one for which the measured

[1] According to Dr. Glenn Miller, acrylonitrile is “perhaps the single best indicator of fracing, and should be considered presumptive evidence that fracing fluids have contaminated the groundwater”, although he also acknowledged that one observation, in a replicated sample, is not proof. Email communication, 9/27/2012.

concentration varies from 70 t 130% of the known concentration which indicates just how variable the test methods are. Even 70% recovery could cause a sample which otherwise should have had a detectable concentration to be missed; a 130% recovery means however that a concentration can be overestimated, although it will not find a constituent in a sample in which it does not exist.

Organics attenuate by interactions with clay and silt sized particles so seasonal changes could be expected. This sampling occurred during late April, a time period during which recharge should be highest, since there is a mound in the shallow groundwater suggesting downward movement of water. Such vertical flow could dilute the formation water and cause seasonal changes not accounted for in spot samples as collected by the USGS.

The concentration of methane and ethane increased substantially and that of propane remained relatively constant. The stable isotope ratios of carbon vs. hydrogen in methane are also almost exactly as found by the EPA. The gas in MW01 is thermogenic, and its concentration is increasing. An increasing concentration of thermogenic gas suggests its source is the formation rather than a leaky gas well. The continued increase in concentration reflects that gas flow from more of the formation has reached the monitoring well, a process which will continue until it reaches equilibrium; in other words, the flow of gas through the formations, released by fracking, could reach equilibrium at the current or a higher concentration. If the formation is the source, the gas contamination will continue as long as the source releases gas.

In summary, the organic chemistry at MW01 has not changed substantially since the EPA sampled the well. The chemistry of MW01 found by the USGS is similar to that found by the EPA (2011). The new data does not disprove the hypothesis made by the EPA that natural gas drilling activities, including fracking, have contaminated the Wind River aquifer near Pavillion WY. The conclusions based on that analysis should be more widely accepted because the water quality has been replicated.

Monitoring Well 2

The USGS did not sample MW02 because the well reportedly yielded only about 1 gallon per hour (Wright et al 2012). This differs from the EPA's purging which for Phase IV reportedly removed 1249 liters (330 gallons) of water prior to sampling; EPA did find that the water level lowered more quickly than they could measure it. The USGS redeveloped the well but this did not improve the yield sufficiently for sampling, therefore they did not obtain a sample.

MW02 had been completed in a layer of sandstone approximately 20 feet thick with a shale confining layer both above and below. The resistivity logs also suggest this should be a productive zone. There is no good explanation for the well's failure to produce sufficient water for sampling, but its failure does not obviate the results found by the EPA for that well. The fact that the well produced substantial water from the sandstone twice indicates that the formation contained the constituents.

Bias Due to Volatilization

Most of the organic chemicals sampled for at the EPA monitoring wells will volatilize, meaning be lost to the air from the sample, under the correct conditions. In general those conditions are due to exposure to air which can be enhanced due to turbulence (Nielsen and Nielsen 2006). Sampling a well just after purging without allowing the well to recover without pumping can cause more volatilization and decrease the amount of constituent recovered in the sample (Herzog et al 1988). Too much purging or purging that causes too much drawdown can also increase volatilization because of the speed with which groundwater flows back into the well (McAlary and Barker 1987). Purging too rapidly or not sampling at the correct time after recovery can cause a bias in the resulting sample concentration. This could have occurred at both the USGS sampling of MW01 and in the EPA's sampling of MW01 and MW02. Concentrations of organics, particularly VOCs, should be considered as potentially low compared to the background groundwater.

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Is fracking behind contamination in Wyoming groundwater?

Questions about whether hydraulic 'fracking' is to blame remain as the US EPA prepares for peer review.

Jeff Tollefson

04 October 2012 Clarified: 10 October 2012

Natural gas extraction via hydraulic fracturing has been linked to contamination in groundwater.

GETTY IMAGES

The US Environmental Protection Agency (EPA) sparked a firestorm in December last year when it released a draft report[1] suggesting that the use of hydraulic fracturing — or 'fracking' — to extract natural gas had contaminated groundwater near Pavillion, Wyoming. Industry officials have long denied that fracking affects groundwater, and Pavillion has become the first high-profile test of this claim. On 26 September, the US Geological Survey (USGS) released data showing the presence of groundwater contamination in the region[2]. Although the data would seem to support the EPA's assessment — as does an independent analysis released by environmental groups this week[3] — the survey did not seek to determine the source of the contamination. *Nature* examines the on-going debate and how it relates to broader questions about groundwater contamination from fracking across the United States.

How did this investigation begin?

After local landowners complained about the smell and taste of their water, the EPA began in 2009 to analyse the groundwater outside Pavillion. The agency tested the water in the shallow wells that tap the groundwater above the 169 gas-producing wells in the field; in two municipal wells in the town; and in several surface and deep wells that it drilled for monitoring purposes. It found evidence of contamination in both the shallow and deep wells, and attributed the shallow contamination to the 33 or so nearby surface pits used to store drilling wastes[1]. The pits could not, however, explain the contamination in the deeper groundwater.

What is the evidence that fracking contaminated the deep groundwater?

A range of hydrocarbons showed up in the deep wells, as did some synthetic organic chemicals associated with fracking fluids and drilling activities. The EPA also found high pH levels that could be explained by potassium hydroxide, which was used in a solvent at the site. The agency also analyzed the evolution of the pollution plume to determine that groundwater seems to be migrating upward, suggesting that the source of contamination came from the gas production zone rather than the surface pits.

Officials with both industry and the state of Wyoming questioned the EPA's data as well as its interpretation, arguing that some hydrocarbons are to be expected through natural migration from the gas field. The state then asked the USGS to conduct a new analysis and provide the data to the state. The USGS provided those data last week[2]; it also sent samples to the EPA, which is conducting its own analysis.

Related stories

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What do the latest results suggest?

The USGS provided only the raw data and no interpretation. An analysis released this week by two environmental groups found that the data support the EPA's original conclusion. A scientist who has investigated possible contamination at other sites, Rob Jackson of Duke University in Durham, North Carolina, says that multiple lines of evidence are certainly "suggestive" of fracking as a source of contamination.

Does this settle the debate?

No. Encana Corporation, an energy producer based in Calgary, Canada, that has wells in the field near Pavillion, maintains that neither the EPA draft report nor the USGS results provide any proof that drilling operations are to blame.

Is this case unique?

There have been allegations of groundwater contamination at other locations where fracking has taken place, but it is not yet clear how common the problem might be. It is less likely, for instance, in regions where the gas is very deep in the ground, such as in Pennsylvania, where production takes place at depths of 1,500 meters or more. In Pavillion, the gas wells are as shallow as 372 metres, while wells tapping groundwater are up to 244 metres deep; this makes communication between the two zones much easier.

A report in February by the University of Texas at Austin's Energy Institute found no evidence of contamination from fracking near wells in Texas, Pennsylvania or New York, but the university is currently reviewing that report after the lead scientist, Charles Groat, was accused of having a conflict of interest (see 'Unfortunate oversight').

A 2011 study in the *Proceedings of the National Academy of Sciences* by Jackson and his colleagues[4] documented high concentrations of methane and other hydrocarbons in groundwater close to fracking operations in Pennsylvania and New York. But Jackson says that the contamination may have come not from the fracking but from the wells themselves, which can serve as a conduit between geological formations if not properly sealed.

What comes next?

The EPA plans to complete its analysis of the water samples and then turn over all of the data for an independent peer review later this year. In a press conference on Tuesday, Wyoming Governor Matt Mead said that the state would analyse the USGS data and then determine whether it needs to change its rules on fracking operations.

In parallel, the EPA is conducting a national assessment of environmental and public-health issues associated with fracking and expects to produce an initial report later this year.

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Clarifications

Clarified: An earlier version of this story did not make clear that an analysis of USGS data by environmental groups found that the data are consistent with but do not confirm - with EPA conclusions about water contamination due to fracking. This has been clarified.

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Comments

2012-10-04 06:49 AM

Sherif Hindi said: Induced hydraulic fracturing is a technique used to increase the released petroleum and/or natural gas. This type of fracturing creates fractures from a wellbore drilled into reservoir rock formations. Potential environmental impacts, including contamination of ground water, risks to air quality, the migration of gases and hydraulic fracturing chemicals to the surface, surface contamination from spills and flowback and the health effects of these factors. For these reasons, hydraulic fracturing has come under scrutiny internationally, with some countries suspending or even banning it. Hydraulic fracturing has raised environmental concerns and is challenging the adequacy of existing regulatory regimes. These concerns have included ground water contamination, risks to air quality, migration of gases and hydraulic fracturing chemicals to the surface, mishandling of waste, and the health effects of all these. Accordingly, a fair decision must be regarded for selecting either profit or human health, especially when the petroleum projects approaches to residential communities. However, accurate fracturing monitoring must be regarded by measuring of the pressure and rate during the growth of a hydraulic fracture, the fluid properties along with geology information that provide the simplest monitoring method. In addition, injection of radioactive tracers is sometimes used for this monitoring task. Furthermore, microseismic monitoring is sometimes used to estimate the size and orientation of hydraulically induced fractures by placing an array of geophones in a nearby wellbore. Tiltmeter arrays, deployed on the surface or down a well, provide another technology for monitoring the strains produced by hydraulic fracturing. Dr. Sherif Shawki Zaki Hindi King Abdull-Aziz Univ. Saudi Arabia

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TECHNICAL MEMORANDUM

April 30, 2012

Review of DRAFT: Investigation of Ground Water Contamination near Pavillion Wyoming
Prepared by the Environmental Protection Agency, Ada OK

Prepared by: Tom Myers, Ph.D.
Hydrologic Consultant
Reno NV

SUMMARY AND RECOMMENDATIONS

After consideration of the evidence presented in the EPA report and in URS (2009 and 2010), it is clear that hydraulic fracturing (fracking (Kramer 2011)) has caused pollution of the Wind River formation and aquifer. The EPA documents that pollution with up to four sample events in the domestic water wells and two sample events in two monitoring well constructed by the EPA between the level of the domestic water wells and the gas production zone. The EPA's conclusion is sound.

Three factors combine to make Pavillion-area aquifers especially vulnerable to vertical contaminant transport from the gas production zone or the gas wells – the geology, the well design, and the well construction. Natural flow barriers are not prevalent in this area, so there are likely many pathways for gas and contaminants to move to the surface, regardless of the source. There is also a vertical gradient, evidenced by flowing water wells, although its magnitude and extend are undefined, to drive advective vertical transport. The entire formation is considered an underground source of drinking water, but 169 gas wells have been constructed into it; this is fracking fluid injection directly into an underground source of drinking water.

The well design is poor because the surface casing does not extend below the level of the water wells, as is required in many other states, and because the wells contain substantial borehole lengths without surface casing or cement between the production casing and the edge of the borehole. This allows vertical transport of gas and fluids and decreases the protection against leakage during fracking or gas production. Third, the EPA documented many instances of sporadic bonding, which simply means the cement does not completely seal the annulus between the production casing and the edge of the borehole. This provides pathways which could allow gas and contaminant transport along the well bore.

The EPA also appropriately accounted for the potential that their monitoring well construction could have explained the contamination. "Since inorganic and organic concentration patterns measured in the drilling additives do not match patterns observed in the deep monitoring wells and because large volumes of ground water were extracted from the wells during development and prior to sampling, it is unlikely that ground-water chemistry was at all impacted by drilling additives."(EPA, 2011, p 7).

The EPA also demonstrated that the inorganic geochemistry in the monitoring wells is substantially different than that which would occur naturally in the area, and that the enrichment of numerous constituents is most likely due to the interaction of fracking fluid with the groundwater near the sampled well. This is particularly true for the elevated levels of potassium, chloride, and pH.

Any of the three contaminant transport pathways suggested by the EPA could be responsible for the contamination moving from the fracking zone to the drinking water wells. The EPA has also presented evidence that contamination in surface ponds has not caused the contamination in the water wells or their monitoring wells.

The situation at Pavillion is not an analogue for other gas plays because the geology and regulatory framework may be different. The vertical distance between water wells and fracking wells is much less at Pavillion than in other areas, so the transport time through the pathways may also be low compared to other gas plays. It is important, however, to consider that the pathways identified at Pavillion could be applicable elsewhere (Myers, 2012; Osborn et al, 2011). In addition to improving and enforcing the relevant regulations, monitoring the pathways between the target formation and aquifers should be standard at all gas plays with fracking.

The following recommendations would improve the analysis and continue the study into the future made throughout this review.

1. The EPA should continue data collection to better verify the sources and map the potential contaminant plumes.
2. EPA should map the gas production wells according to their construction date. The EPA should also compare the locations of observed contamination with the nearby well construction dates to estimate the travel times from the sources to the well receptors.
3. The EPA should map the depth to water prior to sampling in the water wells. Using this, they should map vertical gradients and correlate these gradients to areas with contaminants most likely sourced to deep aquifers.
4. The EPA should install deeper monitoring wells near the shallow pits to better map the depth of the plume emanating from those pits.
5. Data collection should continue so the results can be replicated. An additional, deeper monitoring well should be constructed in the gas production zone between the existing monitoring wells to determine the vertical gradient and estimate the rate of vertical flow.
6. The EPA presents no evidence regarding the extent that fracturing extends above targeted formations. It may not be possible to prove whether this occurred at this site, but the EPA should at least discuss the possibility. It would be useful to perform some simple testing to map the extent of fractures, as described by Fisher and Warpinski (2010).

INTRODUCTION

The Environmental Protection Agency (EPA) has released a study of groundwater contamination in the Pavillion gas play in west-central Wyoming. Their preliminary conclusion is that gas well development and hydraulic fracturing (fracking (Kramer, 2011)) has caused the contamination. The EPA report is in draft form and is open for comment until March 12, 2012. This technical memorandum reviews the EPA report. This review was prepared with support from the Natural Resources Defense Council, Wyoming Outdoor Council, Earthworks, Oil and Gas Accountability Project and Sierra Club.

This review discusses in detail the appropriateness of the study design, methodology, execution, results, and interpretation and the reasonableness of the conclusions. It specifically follows and considers the EPA's "lines of reasoning" approach used to reach its conclusion.

STUDY AREA

The study area is in the Pavillion gas field in west-central Wyoming. It lies northeast of the Wind River Range. The general geology for uppermost 1000 meters (m) is the Eocene-aged ((56 to 34 million years before present) Wind River Formation, which is interbedded sandstone and shale with coarse-grained meandering stream channel deposits. The presence of stream channel deposits indicates that the formation has been carved by river beds which left fluvial deposits interspersed among formation layers These fluvial deposits often provide connectivity among formation layers and can fragment otherwise continuous sedimentary layers.

The area has experienced gas development since the 1960s, with 169 gas wells constructed in the study area. EPA Figure 2 shows the gas well construction chronology. There were three main periods of construction – 1963-65, 1975-83, and 1998 – 2006, with each subsequent period having more new wells constructed than the previous period. EPA does not specify when fracking first occurred, however.

Recommendation: Add a map of gas production wells coded for the year or time period during which the well was completed (or fracking occurred if substantially different). This would allow an assessment of travel time for contaminants to flow from production zones to the monitoring wells and domestic wells.

The US Geological Survey studied the water resources on the Wind River Reservation (Daddow 1996), which surround this study area (but does not include it). The Wind River Formation is the primary source of drinking water on the reservation. Daddow's (1996) description of the formation indicates that the formation consists of interbedded shale and sandstone with extremely variable permeability that could lead to highly variable contaminant loads throughout the formation (Osiensky et al 1984).

Recommendation: A more detailed description of the geology and hydrogeology of the area, perhaps based on the relevant Geological Survey reports would provide more insight regarding geochemical trends as found by the USGS.

STUDY LAYOUT AND DESIGN

EPA started this study in response to citizen complaints regarding contamination in their water wells. EPA established dedicated monitoring wells after two rounds of sampling various water wells rather than prior to construction of the gas wells. For much of their study data, the EPA had to use sample data collected from existing water wells. Water wells are not the best tool for monitoring groundwater quality because, even if the well construction is of similar quality to a dedicated monitoring well, water wells have much longer screens, or open intervals, than do monitoring wells. They screen the most productive formation layers, usually based on observations made during drilling, to maximize the pumping rate while minimizing the drawdown. Wells drilled specifically for monitoring wells also screen productive zones, but target the screen to a specific zone, usually 20 feet or less thick, so that the sample represents a given aquifer level.

Samples from water wells are therefore a mixture of water from all productive zones of the entire open interval, weighted according to the transmissivity of each zone. A domestic water well sample is useful for determining whether a contaminant exists at some point in the aquifer, but a dedicated monitoring well is necessary to determine which layer is contaminated.

EPA established two dedicated monitoring wells to supplement the data obtained from the water wells. The new monitoring wells were primarily screened below the level of the water wells (Figure 1) and above the gas production wells to "differentiate potential deep (e.g., gas production related) versus shallow (e.g., pits) sources of groundwater contamination" (EPA p 5). The EPA established just two monitoring wells due to a limited budget (Id.). EPA placed the monitoring wells' screened interval along the conceptualized vertical pathway between the potential contaminant source (i.e. the production wells and/or zone) and the water wells. The monitoring wells were designed appropriately to detect and monitor contaminant movement upward from the production zone to the water wells; if the monitoring wells had been constructed at the same depth as the water wells, they would not have added substantial useful information.

Figure 1 (EPA Figure 3) shows that domestic water wells in the regions are screened at all levels down to about 250 m, or more than 800 feet, with half of the wells being deeper than 300 feet, similar to the depths found by Daddow (1996) in other areas of the aquifer. However, the EPA states the information source was from the State Engineer *and* homeowner interviews (EPA p 2). It is unclear whether both were used for each well. It is my experience that homeowners have a poor concept of the depth of their well unless they have paperwork that documents it.

Recommendation: The EPA should provide more information about the source of its water well construction data, showing it in EPA Table A1.

The following table summarizes in general terms the wells that were sampled during each sampling phase (other media were also sampled but not included in this table). It is apparent that the wells sampled in phases subsequent to the first phase depended in part on the results of the prior phases.

Phase	Date	Domestic and Stock Wells	Municipal Wells	Stock Wells	Monitoring Wells	Comments
I	3/09	35	2	0	0	
II	1/10	17 (10 previously sampled)	2	4	0	This phase came about because EPA had detected methane and dissolved hydrocarbons during Phase I.
III	10/10	3 (2 previously sampled)	0	0	2	Gas samples also collected from the well casing of EPA's two deep monitoring wells.
IV	4/11	8 previously sampled	0	3 previously sampled	2	Added glycols, alcohols, low molecular weight acids

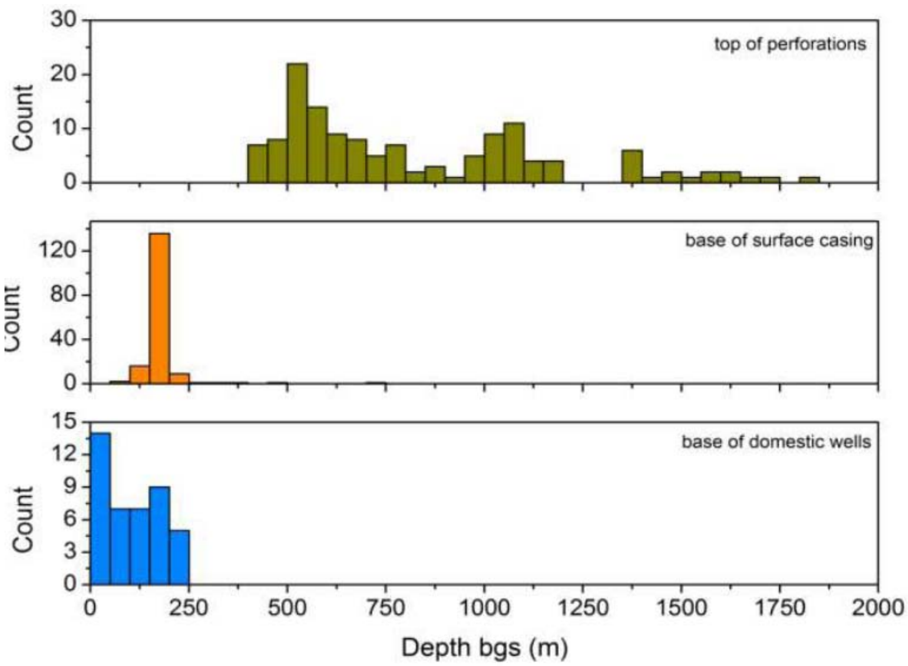

Figure 1: Snapshot from EPA (2011) Figure 3 showing frequency of depth for gas wells (top), surface casing for gas wells, and base of domestic wells.

EPA Table A1 lists the wells and the phase during which they were sampled, broken into eight data types.

1. anions and alkalinity
2. metals
3. alcohols and VOCs
4. low molecular weight acids and glycols
5. semi-volatile organic compounds (SVOCs), pesticides, PCBs, and tentatively identified compounds (TICs);

6. gas/diesel related compounds, and hydrocarbons
7. bacteria
8. fixed gases, heavy hydrocarbons, dissolved carbon, and gas and water isotopic ratios

EPA Table A2a presents the geochemical results – anions, cations, and alkalinity. Unfortunately, this table does not consistently state in which phase the initial sample was taken. Additional samples are identified with a suffix on the sample number. The other data tables in Appendix A provide results by phase, but some results are found only in other reports, including URS (2009 and 2010).

URS (2009) reports the Phase 1 sampling (water wells only) in their Table 9, which shows concentration of SVOC contaminants, including caprolactam at 1.4 ug/l at PGDW20, dimethylphthalate detected at nine wells, and Bis (2-ethylhexyl)phthata at 9.8, 6.4 and 12 ug/l in PGDW25, -20 and -14[1], respectively, and detect levels at ten other wells. Total purgeable hydrocarbons were 26 and 25 ug/l in wells PGDW05 and PGDW30, respectively. Measurable methane concentrations were found in 8 wells. Total purgeable organics are generally gasoline and diesel range organics. PGDW25 is one of the deeper wells at 243.8 m below ground surface (bgs) and PGDW05 and -30 are at 64.0 and 79.2 m bgs, respectively. URS (2010) reports the Phase 2 sampling in more detail. It shows more than 20 wells with detectable levels of a variety of semi-volatile organics (URS 2010, Table 9). The report does not assess these detects with the depth of the well, but a quick glance suggests that most of them are on the deeper half of the domestic wells. An exception is PGDW39, reported to be just 6.1 m deep, although the EPA should consider whether "6.1" is correct because if so it would be tens of meters shallower than any other water well in the aquifer.

Recommendation: The EPA should present and discuss the correlation of contaminant detects in the domestic wells with depth.

EPA based this study on four sample events including various subsets of domestic, municipal, and stock wells and two sample events in the monitoring wells. A reasonable question is whether the number of samples is sufficient for developing an opinion? A time series would help to identify a trend, but is not necessary to establish presence/absence. Objections to this data on the basis of there being just two samples are without merit – simple presence of a substance that would not naturally occur in the aquifer, if other causes can be eliminated, is sufficient to reach a preliminary conclusion that fracking fluid has affected the aquifer. However, the EPA should continue the sampling to determine whether the concentrations are trending higher, or not, and determine how or whether the plume expands.

TRANSPORT PATHWAYS

The EPA identifies three potential pathways for contaminants to reach the water wells from the fracking (EPA, p 32).

- Fluid and gas movement up compromised gas wells.

[1] The table did not highlight the values at PGDW14 and -20 as being exceedences.

- Fluid excursion from thin discontinuous tight sandstone units into sandstone units of greater permeability.
- Out-of-formation fracking, whereby new fractures are created or existing fractures are enlarged above the target formation, increasing the connectivity of the fracture system.

The EPA does not conclude which or whether any of these pathways actually facilitated the contamination at Pavillion, although arguments throughout the document (and reviewed in this report) support the potential for any of them. EPA correctly notes that for all three pathways there would be a correlation between the concentration of gas in the water wells and the proximity to gas well, as found by Osborn et al (2011) in the Marcellus shale in Pennsylvania. They also note that for all three pathways, "advective/dispersive transport would be accompanied by degradation causing a vertical chemical gradient" (EPA, p 32) as discussed in other portions of the report. In other words, with increasing distance from the source, both vertical and horizontal, the contaminant concentration would decrease. This would be due in part to chemical degradation, dispersion of a finite mass over a larger volume, attenuation due to chemicals adsorbing to soil particles, and dilution by mixing with groundwater..

The following sections consider evidence from various aspects of the EPA report in context of the pathways.

Lithologic Barriers

Very low permeability layers can prevent or impede the upward movement of fluid or gas from depth to the water well zone, which in the Wind River Formation is the upper 250 meters (based on the reported water well depth). Extensive layers of shale are often sources of gas and/or capstones, which prevent gas in underlying sandstone from escaping to the surface. However, the shale must be horizontally extensive and not fractured to be an effective seal, which is not the situation in the Pavillion field as quoted above. The formation is most productive (for gas) at its base with gas trapping occurring in "localized stratigraphic sandstone pinchouts on the crest and along flanks of a broad dome" (EPA p 2).

Hypothesis: The lithology in the Pavillion area does not prevent the vertical movement of gas or contaminants to the surface because it is either not sufficiently extensive or impervious. EPA claims there is no "lithologic barrier … to stop upward vertical migration" (EPA p viii) and also that "there is little lateral and vertical continuity of hydraulically fractured tight sandstones" (Id.).

Evidence: EPA presented a lithologic cross-section (Figure 20) showing mapped shale layers, production, water, and monitoring wells and the points where the production wells had been fracked. EPA found that the lithology is "highly variable and difficult to correlate from borehole to borehole" (EPA p 15). "Sandstone and shale layers appeared thin and of limited lateral extent" (Id.). Pathways could go around the intermittent shale so that contaminants in a given monitoring well may not result from the nearest production well. Pathways for movement through sandstone could be tortuous (EPA p 37); vertical pathways through sandstone could be more tortuous than horizontal pathways because the particles in sandstone tend to be elongated with the longer side being horizontal.

Fracking has occurred for up to 45 years, so there is potential for many pathways from various sources to a receptor well. The travel time to a given point could be any time period up to 45 years. Additionally, out-of-formation fracking occurring at any time could have shortened the pathway.

Conclusion: The lithology in most areas would not prevent the vertical movement of contaminants to the water wells because of the lateral variation.

Vertical flow and gradient

In order for contaminants to move from the fracked zones or from deep well bores to surface aquifers, there should be a vertical hydraulic gradient. Lacking such a gradient, movement could still be possible due to lateral dispersion and upward concentration gradients, but it would be much slower.

Hypothesis: There is upward flow in the Pavillion gas field that would support advection of contaminants associated with fracking fluids to the monitoring and water wells.

Evidence: In the Pavillion area, there are flowing wells, which would indicate an upward gradient, at least at depth, which could drive vertical advection, or contaminant transport with the groundwater flow . Daddow (1996) also documented flowing wells in other areas of the Wind River Range, with the depth range from 225 to 450 feet bgs. EPA uses PGDW44 as an example (p 36). This water well lies near the middle of the field near MW01. MW01 showed a depth to water equal to 61.2 m at the beginning of a purge for sampling (p 11 and Figure 8). MW02 had depth to water of 80.5 m (p 12). The depth to water in the monitoring wells does not support the idea of an upward gradient, but being the only wells at that depth, the data is not conclusive. Table A1 reports the PGDW44 well depth is 228.6 m; PGDW25 is deeper, at 243.8 m bgs. MW01 is just 10 m deeper. There is apparently an upward gradient at that point because the well is flowing, but the analysis could be improved, as follows.

EPA documents that the shallower monitoring well has more natural breakdown products of the organic contaminant like BTEX or glycol that are found in the deeper monitoring well and in fracking fluids (p 36). It suggests that the contaminants in the shallow well are derived from the natural breakdown of the contaminants found in the deeper well. This could only occur if the wells represent a vertical flow path, which they do and therefore these findings support the hypothesis of upward movement.

The gas found in the deep Wind River Formation is chemically similar to gas in the underlying Fort Union Formation suggesting that gas in the Wind River Formation has naturally moved upward until captured in localized capstones, or “localized stratigraphic sandstone pinchouts” (EPA, p 2). EPA concludes that differences in gas composition and isotopes support the hypothesis of upward migration through the various layers in the Wind River formation (p 29). The fraction of ethane and propane in the gas from domestic wells is mostly less than in the produced gas, but the isotopic composition is clearly thermogenic, which suggest there is an ongoing “preferential loss of ethane and propane relative to methane” (p 29, 38). This evidence supports the hypothesis of upward fluid and gas movement.

Vertical movement could occur in the absence of a vertical gradient, if the pressurization caused by the fracking is sufficient and there is a poorly developed well bore nearby. Contaminants can migrate quickly upward through a leaky borehole due to the transient pressure gradient across an aquitard created by the fracking pressure (Lacombe et al, 1995).

Conclusion: There is evidence to support the concept of upward movement in the area, but it is not conclusive. The EPA should complete more studies documenting the vertical hydraulic gradient throughout the area.

Recommendation: The EPA report should document the depth to water in the domestic wells prior to sampling so that they could map water levels for different well depths and determine the zones of upward gradient.

Contamination from shallow pits

The presence of shallow disposal pits is an alternative source of contamination. EPA notes that there are 33 shallow pits that had been used for the "storage/disposal of drilling wastes, produced water, and flowback fluids in the area of investigation" (EPA p 17). As part of this study, the EPA communicated with stakeholders to further determine the location of pits. Shallow monitoring wells have found very high concentrations of several contaminants that were also found in deeper water wells and the EPA monitoring wells. These pits could have received the detritus of fracking operations in the past.

Hypothesis: Contaminated water seeping from these pits could be responsible for the observed contamination.

Evidence: Shallow monitoring wells that had been installed previously for reasons not associated with this project (EPA, p 11) are reported to have very high contaminant concentrations, although this data is not well summarized in the report. The shallow monitoring wells are only 4.6 m bgs (EPA p 17), so there is little information about how deep the contamination extends beneath the pits. Assuming the pits are some distance away from homes and people avoided them when constructing their water wells, it is possible the shallow disposal pits are sources of contamination beyond the level the EPA considers shallow, or 31 m bgs (Id.).

Irrigation could help to contain the contamination near the shallow pits because they would be located in low recharge areas, either by design or in comparison with irrigated fields. It would be unlikely that the pits would have been constructed within irrigated fields, so the seepage from the pits may be much less than the seepage beneath irrigated fields because of the continuous application of water to the field, and for a much shorter time period. Irrigation water would have seeped deeper and faster due to the likely higher rate of application and effectively diluted or prevented the deeper circulation of seepage from the pit.

Conclusion: The EPA concludes that these shallow pits are not the source of contaminants found in deeper water wells. Because there is little contamination in intermediate-depth wells, their conclusion is sound, but the document would benefit from more analysis and discussion.

Recommendation: The EPA should document more fully the contaminant plumes near the pits. Specifically, deeper monitoring wells near the pits should be constructed to construct a contamination *profile beneath the pits. Better investigation of the pits as a source would also facilitate the remediation of the groundwater near those pits.*

LINES OF REASONING

The EPA used a line of reasoning analysis regarding the presence of fracking fluid constituents and gas in monitoring wells in support of their preliminary conclusion that fracking has contaminated aquifers in Pavillion Wyoming. This is critical because the conclusion is not just that leakage from the wells or spills caused contamination, but that the fracking process itself caused the contamination. EPA deemed the multiple lines of reasoning approach necessary due to the complexity in detecting contaminants in groundwater from deep sources. This section critically reviews each of the EPA's lines of reasoning.

High pH Values

The EPA monitoring wells both have very high pH, ranging from 11.2 to 12.0, which is much higher than the level seen in the domestic water wells in the Wind River formation. EPA concluded the high pH was due to hydroxide (OH) which indicated the addition of a strong base to the background water (EPA p xii). EPA's reaction path modeling suggested that the addition of just a small amount of potassium hydroxide to the sodium-sulfate waters typical of deep portions of the Wind River formation would cause such a pH change; EPA concludes from the modeling that the typical groundwater in the Pavillion aquifer "is especially vulnerable to the addition of a strong base" (EPA p 20).

Potassium hydroxide was used as a crosslinker and solvent for fracking the production wells in the area (EPA p 33), which could be a source of the OH to increase the pH of the water in the area of the production wells.

The use of soda ash as a drilling additive when drilling the monitoring wells, often to control the pH, is a possible alternate explanation for the elevated pH[2]. Soda ash is 100% Na_2CO_3. At a 1:100 mixing ratio with water, the pH of dense soda ash was 11.2 (EPA Table 2). The recommended ratio for use in fracking fluid is 1:100 to 1:50 (EPA Table 1). The pH of drilling mud varied between 8 and 9. The concentrations of neither sodium nor carbonate are abnormal in the monitoring wells. If the soda ash did separate from the drilling mud, mixing with background groundwater would further dilute it so that the pH would be less than observed at the 1:100 mixing ratio.

EPA Figure 12 verifies these pH values are higher than in the domestic wells, but also shows they fall on the general trend of pH with elevation of the well open interval. Based on this information, it is not possible to conclude that the high pH is not natural, but the EPA's conclusion appears to be justified based cumulatively on all of the facts concerning pH. EPA should consider geophysical logging completed by the industry if it includes pH logs to improve their analysis; such logs could provide pH values for deeper areas that could be compared with the pH values for their monitoring wells.

[2] http://www.halliburton.com/ps/default.aspx?navid=125&pageid=60&prodgrpid=MSE%3a%3a1053024648177449, visited 1/13/12

Chemistry in the shallow wells has been affected by irrigation with Wind River water. This irrigation water has very low total dissolved solids (TDS) and neutral pH (<8) (EPA Figure 11) but the other shallow groundwater wells show that the irrigation water picks up contaminants as it seeps.

The methods used to collect samples probably minimized contamination causing high pH in the monitoring wells. EPA purged the monitor wells until pH stabilized, a process which would minimize the potential that any residual contamination from well development would have been sampled.

EPA's analysis associated with Figures 11 and 12, explaining the shallow water geochemistry, is accurate and useful. It utilizes data from all of the wells in the area and surface waters to show water chemistry trends through the study area. It also shows how EPA's monitoring wells differ substantially from the general trends, supporting the conclusion that elevated pH in water samples from EPA's deep monitoring wells was likely caused by contamination with hydraulic fracturing chemicals.

Elevated potassium and chloride

The monitoring wells both have concentrations of K and Cl much higher, 14 to 18 times, than the domestic water wells (EPA p 34). Potassium concentration ranged from 43.6 to 53.9 mg/l and Cl concentration averaged 466 mg/l (Id.). The drilling additives reported by EPA to have been used at Pavillion had a much lower concentration for both anions. The fracking fluid contained several compounds with high concentrations of both ions (Id.). Therefore, the high concentrations of K and Cl suggest contamination with fracking fluid.

The chloride concentration data plotted in EPA Figure 12 shows clearly that Cl concentration in two of the three samples from EPA's deep monitoring wells are much higher than those in domestic wells, and EPA correctly assesses there must be a cause other than natural variation for the high concentrations. However, in this case I disagree with EPA's assessment that "regional anion trends tend to show decreasing Cl concentrations with depth" (EPA p 19) because EPA Figure 12 shows little variation with depth although there are a couple of high concentration outliers near the surface. Regardless of the interpretation of trend, concentrations from the EPA monitoring wells plot far higher than the Cl data from domestic wells.

The chloride concentrations reported from the EPA monitoring wells are also much higher than reported by the USGS in their Wind River study (Daddow 1996). He describes the formation water as having TDS concentration as high as 5000 mg/l, but Cl is a small proportion of that. He also reported that the highest Cl concentration on surface water sites was less than about 30 mg/l, so assuming the river recharges the alluvial aquifer, the source of the groundwater is relatively clean with respect to chloride. Cl concentrations at EPA's monitoring wells are much higher than the regional values reported by USGS in either ground or surface water on the Wind River Reservation, and are unlikely to be properly considered "naturally occurring".

For potassium, it is much clearer that the monitoring well concentrations exceed the domestic water well concentrations by many times (EPA Figure 12, p 20).

There is too little of either K or Cl in drilling mud or additives for it to have been the source or cause of the enrichment in the monitoring wells. Also, purging prior to sampling occurred until the specific conductivity (SC) of the purged water reached a relative steady state (EPA Figure 9). K and Cl both contribute to the SC of the water being sampled. Any potential contamination due to well construction or development has most likely been purged from the system.

The high K and Cl concentrations are clearly present in the formation water near the monitoring wells. Without a natural source as explanation, the mostly likely source is the fracking fluid which used compounds that have high concentrations of both anions. EPA has reasonably concluded the most likely source of elevated K and Cl is fracking fluid.

Detection of synthetic organic compounds

The EPA found in the monitoring wells significant concentrations of isopropanol, diethylene glycol, triethylene glycol, and tert-butyl alcohol (TBA) (in MW02). TBA was not directly used as a fracking fluid, but "is a known breakdown product of methyl tert-butyl ether and tert-butyl hydroperoxide". The first three products are found in fracking fluid based on the material safety data sheets (MSDSs) analyzed by EPA, but the parent compounds of TBA have not been reported as such; importantly, MSDSs, which are the source of the fracking fluid additives lists in the report, do not list all chemicals because the formulas are proprietary. That a chemical is missing from the list of additives is not evidence they were never in fracking fluid.

Isopropanol was found in "concentrated solutions of drilling additives" at concentrations much lower than detected in the monitoring wells (EPA p 35) and the others, glycols and alcohols, were not used for drilling.

None of these compounds naturally occur in groundwater. The EPA is correct in its conclusion that there is no acceptable alternative explanation and the most likely source of these contaminants is fracking fluid.

Detection of petroleum hydrocarbons

EPA detected benzene, toluene, ethylbenzene, and xylenes (BTEX), trimethylbenzenes, and naphthalene at MW02 (EPA, p 35). They detected gasoline and diesel range organics at both monitoring wells (Id.). These are not found in drilling additives, but the MSDSs showed a long list of additives in the fracking fluid that could be the source of the contamination just cited (EPA p 35, 36). For example, a BTEX mixture had been used in the fracking fluid as a breaker and a diesel oil mixture was used in guar polymer slurry (Id.).

EPA rejects alternative explanations that claim that substances, used on the well or pump, caused these contaminant detections. Specifically, the agency points out that the contact time for water with the well or pump during purging and sampling would be so low that contamination would be unlikely, especially after purging. This would be especially true for the Phase 4 sampling which would have occurred after the well had been purged for sampling twice and had several months of natural groundwater flow through it.

An alternate explanation considered by EPA is that the constituents are due to the groundwater being above a natural gas field. In fact, the EPA has noted that historically some wells encountered gas at levels shallower than the monitoring wells. EPA encountered methane while logging MW01 (EPA p 11). EPA notes that the gas from the Wind River formation is "dry and unlikely to yield liquid condensates" (EPA p 36). They also argue that the monitoring wells have substantially different compositions of liquid condensates, which would not result if they came from a common source of gas. The explanation is reasonable, unless there is a variation with depth. Because these contaminants occur only at low concentrations in the deepest domestic wells, the data does not rule out a natural gradient from the gas sources at depth to the shallower zones of the formation. However, the EPA explanation is supported by the fact that the monitoring wells are far enough apart, more than a mile, that they must have different gas well sources and represent different pathways..

Recommendation: To further decrease the uncertainty, the EPA should complete an additional sampling event with more domestic wells sampled. It would also be desirable to have another monitor well screened at the level of the gas wells. The EPA could then develop a concentration profile as a function of depth and formation layer.

Breakdown products of organic compounds

EPA verified a vertical pathway by showing that organic compounds in the shallower monitoring wells are daughter products of the organic compounds found in the deeper monitoring wells. This supports the concept of upward migration with ongoing biologic transformation or natural degradation. It supports the concept of an upward flow gradient. It cannot be asserted that the EPA monitoring wells are on the same flow pathway, as they are more than a mile apart, therefore, the presence of contaminants in the monitoring wells is evidence that there are multiple sources of contaminants at the level of the gas production wells.

As part of this line of reasoning, the EPA presents the "hypothetical conceptual model" that "highly concentrated contaminant plumes exist within the zone of injection with dispersed lower concentration areas vertically and laterally distant from the injection points". This refers to how the fracking fluids, once injected, simply disperse in all directions because there are no confinements, similar to how they disperse from coal seam fracking. It is consistent with the lower concentrations found further from the source.

EPA's hypothesis is reasonable and explains the vertical movement of contaminants from a broad zone of production wells. Its simplicity indicates that fracking in such a formation will eventually lead to contamination moving vertically from the gas wells – it is only a matter of time (Myers, 2012).

Sporadic bonding outside of production casing and hydraulic fracturing in thin discontinuous sandstone

The last two lines of reasoning are considered together because they describe two pathways for fracking fluid to get into the aquifer. The fracking that occurs in the Pavillion gas field directly injects fracking fluid into an underground source of drinking water. Fracking occurs as little as 150 m below the bottom of the deeper water wells. The sandstone and intervening shale zones are discontinuous, which suggests there are no significant continuous barriers to a vertical component of flow and contaminant movement. Fracking has also occurred for up to 40 years, so the pathways could have required up to 40 years for transport. Sporadic bonding above the zone being fracked basically means the annulus between the production zone and surface casing may not be fully sealed with cement which may allow gas or fluids to move vertically among formation layers. During fracking, the high pressure could force some of the fracking fluid through improperly sealed well bores to contaminate formations nearer the water wells.

Both of these lines of reasoning correctly describe potential pathways and sources of fluids in the aquifer. The EPA's conclusions in this regard are reasonable and appropriate and conform to the available facts and data.

Gas in Monitoring and Shallow Wells

Many shallow water wells have gas concentrations that exceed expected background levels. EPA also uses several lines of reasoning to conclude that gas has migrated to domestic wells from the fracked zones, in addition to or instead of it occurring naturally in those wells.

Isotopic composition of gas samples from shallow wells, deeper monitoring wells and produced gas are all similar in that all have a thermogenic origin. However, the shallower domestic water wells have very little higher chain carbon-based gas, which suggests some dispersion and decomposition with vertical movement (ethane and propane degrade faster). The isotopic composition of most wells is thermogenic and indicative of a deep source; URS (2010) noted that methane in one domestic well of eight sampled with measurable methane had biogenic origins.

EPA also found that the concentration of methane in domestic water wells was generally higher in areas of higher gas production, as counted by the number of gas wells. Although it could be coincidental because more gas wells are constructed where more gas naturally occurs, this seems unlikely because the presence of gas in domestic water wells shows that gas is occurring outside of the production zones deep in the Wind River Formation or high in the underlying Fort Union Formation. Gas would only move naturally from depth to areas near the surface if there is a lack of containment which would have depleted the gas source at some point in the last 40,000,000 years. Thus, the gas wells have apparently provided a migration pathway for gas released by fracking into overlying formations; this migration occurred at a rate sufficient to allow gas to accumulate to a concentration capable of causing a blowout at 159 m bgs near well PDGW05.

The area also generally has gas well designs that are below current industry standards in some states, with surface casing not extending below the maximum depth of water wells and with a "lack of cement or sporadic bonding of cement outside of production casing" (EPA p 38). This would provide a pathway from depth to at least the bottom of the surface casing, and allow gas leakage to higher levels in the aquifer. Many states and areas require surface casing to extend below the maximum depth of USDWs (a USDW must generally have TDS less than10,000 mg/l). The gas well design in Pavillion appears to be below industry standards because the surface casing does not extend even below the bottom of the zone of domestic wells. The pathways discussed above for fluid movement would also facilitate gas movement (Id.).

The EPA acknowledges that poorly sealed domestic wells could also be a pathway (EPA p 38-39). This is true but not a relevant argument because the gas wells are much deeper and actually tap formation layers with gas. Once gas reaches a domestic well, it is possible that the well provides an additional pathway, but it is not the source of the contamination or the primary pathway from the gas source zone to the aquifers.

The EPA also references the fact of citizen's complaints (EPA p 39) as an indicator that gas contamination started after fracking. Citizens do not complain until a problem occurs. Assuming their water well was initially acceptable, they would complain when they noticed a change.

DISCUSSION OF CONTAMINANT TRANSPORT PATHWAYS

The general dispersion of contaminants upward from the fracking zone would result from either well bore transport or transport through overlying higher permeability sandstone. Transport through wellbores that cross multiple aquifer layers, as the gas wells do near Pavillion, would allow contaminants to reach the different levels. However, the concentration reaching shallower formations would be much less because the contaminants bleed off to the deeper aquifer zones (Nordbotten et al 2004). Fracking could also create the vertical gradient to temporarily cause contaminants to move vertically upward through wellbores to contaminate shallower aquifer layers (Lacombe et al 1995).

Because there are not any significant horizontal confining units within the Pavillion Field, the upward vertical contaminant transport is partially due to dispersion through relatively porous media. In areas with extensive horizontal confining layers, such as the Marcellus shale areas, transport through vertical fractures, similar to that through wellbores, could transport substantial contaminant mass through the impervious zones (Myers, 2012). If the bulk media bounding the fractures have conductivity less than one hundredth that in the fracture, the contaminants will transport with little dispersion, or loss, into the bulk media (Zheng and Gorelick, 2003).

This appears to be the case in the Pavillion Field, given the existing geology. Thus, unless fracking is very carefully done, and well bores are solidly (not intermittently) bonded, this result is to be expected. In the case of the Pavillion Field, sporadic bonding is revealed and reported for 9 of the wells that EPA examined well bore data made available to them. To the extent that this is indicative of the entire field, it would greatly increase the likelihood that transport of contaminants from the gas wells to the water wells of the rural Pavillion residents would occur.

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

Subject: Action Memorandum - Request for Funding for a Removal Action at the Dimock Residential Groundwater Site, Intersection of PA Routes 29 & 2024 Dimock Township, Susquehanna County, Pennsylvania

From: Gerald T. Heston for Richard M. Fetzer, On-Scene Coordinator
Eastern Response Branch (3HS31)

JAN 19 2012

To: Dennis P. Carney, Associate Division Director
Hazardous Site Cleanup Division (3HS30)

I. PURPOSE

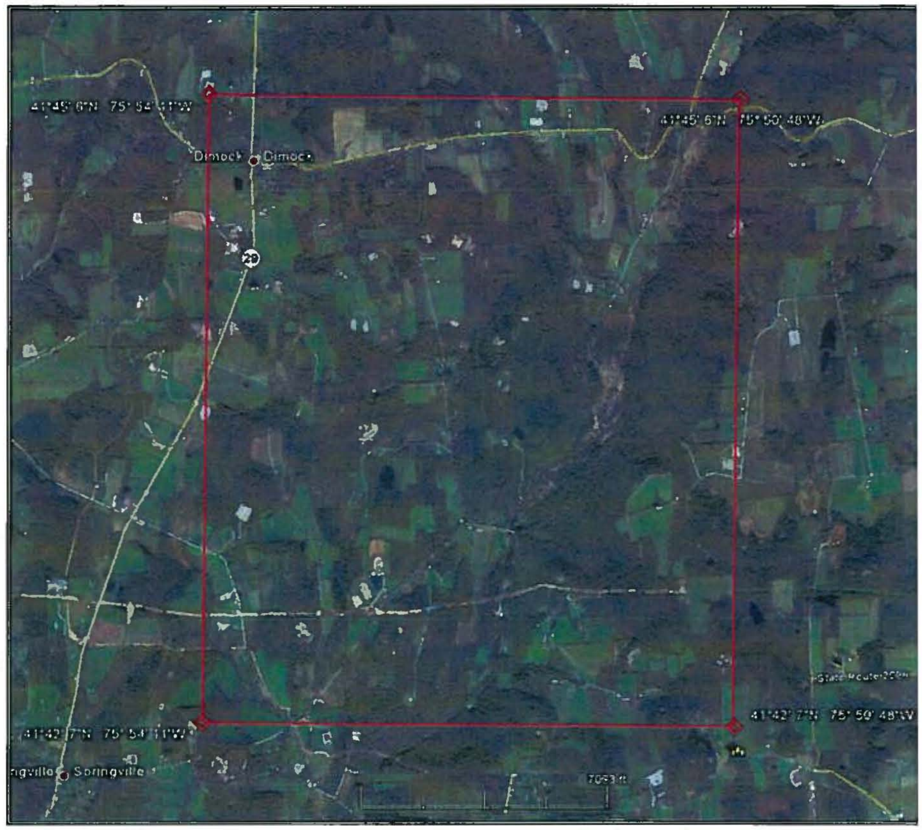
The purpose of this Action Memorandum is to request and document approval of an emergency removal action to prevent, limit, or mitigate the threats posed by the presence of hazardous substances at the Dimock Residential Groundwater Site (the "Site"), pursuant to Section 104(a) of the Comprehensive Environmental Response, Compensation and Liability Act, 42 U.S.C. § 9604(a) (CERCLA). The Site is located in Dimock Township, Susquehanna County, Pennsylvania. The OSC has initiated a removal site evaluation in accordance with the National Oil and Hazardous Substances Pollution Contingency Plan (NCP), 40 C.F.R. Part 300. The OSC has determined, based on Pennsylvania Department of Environmental Protection (PADEP) and Cabot Oil and Gas Corporation (Cabot) sampling information, consultation with an EPA toxicologist, the Agency for Toxic Substances and Disease Registry (ATSDR) Record Of Activity (AROA), issued 12/28/11, and the recent EPA well survey effort, that a number of home wells in the Dimock area contain hazardous substances, some of which are not naturally found in the environment. Inorganic hazardous substances are present in four home wells at levels that present a public health concern. These four specific homes have been dependent upon donated water for drinking and/or household use and the reliability of the sources for donated water is at this point uncertain.

Historic drilling activities in the Dimock area may have used materials containing hazardous substances. Spills and other releases have been documented by PADEP from these drilling activities. There is reason to believe that a release of hazardous substances has occurred. The presence of hazardous substances in the four home wells constitutes a release or substantial threat of a release and the situation meets the criteria for conducting a removal action under Section 300.415 of the NCP. The OSC has determined that funds in the amount of $100,000 are needed to mitigate the human health concern initially at four homes and therefore proposes the actions included in this Action Memorandum. This action includes provision of alternate water to four homes and home well sampling at approximately 61 homes within the Site area.

II. SITE CONDITIONS AND BACKGROUND

A. Background

1. Site Description - The Site area is located in Dimock, a rural area of northeastern Pennsylvania in Susquehanna County. A map of the area is included below.
2. History - Cabot began drilling for natural gas in the Dimock area in 2008. Methane contamination was detected in private wells thereafter in concentrations exceeding those previously found. PADEP had the lead in investigating the environmental complaints in Dimock. PADEP entered into a Consent Order and Agreement (CO&A) with Cabot which required permanent restoration or replacement of the



affected water supply. A public water line was initially considered. PADEP later modified the CO&A to require installation of "gas mitigation" systems for 19 homes served by 18 private wells in the Site area.[1] Until the gas mitigation systems were installed, Cabot was to provide a temporary water source. Some well owners, within the scope of the PADEP CO&A, have gas mitigation systems installed, but others do not. While the gas mitigation systems were designed to remove methane, a potential exists that they may remove some hazardous substances as a by-product of their operation. Regardless, EPA does not know what, if any, hazardous substances these "gas mitigation" systems, originally designed to address methane, are removing. Therefore, EPA is including both pre- and post-treatment sampling in the scope of this action. Furthermore, there are

[1] It had originally been reported that 19 homes were served by the 18 wells included within the scope of the CO&A but the door-to-door home well survey conducted to date by EPA has identified that there are currently 21 homes served by 20 wells on those same properties.

other homes served by private wells that were not covered by the scope of the PADEP CO&A, but are within this Site area.

III. Quantities/Types of Substances Present

1. Arsenic* – Arsenic is a naturally occurring element widely distributed in the earth's crust. Arsenic may also be present at elevated concentrations in the groundwater due to the use and effects of drilling fluids. Arsenic is classified as a known human carcinogen. This classification is based on animal and human studies, which indicate an increased risk for developing cancers of the skin, lung, bladder, kidney, liver, and prostate from consuming arsenic containing water. Non-cancer health effects associated with ingestion of arsenic include circulatory problems and skin damage.
2. Barium – Barium is a silvery-white metal that exists in nature only in ores containing mixtures of elements. It combines with other chemicals such as sulfur or carbon and oxygen to form barium compounds. Barium sulfate is sometimes used by doctors to perform medical tests and to take x-rays of the gastrointestinal tract. Ingesting drinking water containing levels of barium above the EPA drinking water guidelines for relatively short periods of time can cause gastrointestinal disturbances and muscle weakness. Ingesting high levels for a long time can damage the kidneys. Barium is known to be a common constituent of drilling fluids.
3. Bis(2-ethylhexyl)phthalate (DEHP)* - DEHP is a manufactured chemical that is commonly added to plastics to make them flexible. The phthalates are generally considered to be of slight to moderate toxicity. DEHP may be irritating to the eyes, skin, and mucous membranes. Mild gastric disturbances and diarrhea may occur following ingestion of larger doses. Central nervous system (CNS) depression may occur if large amounts of phthalate acid esters are absorbed. EPA has determined that DEHP is a probable human carcinogen. These determinations were based entirely on liver cancer in rats and mice. DEHP is known to be associated with drilling activities.
4. Glycol Compounds (including Ethylene Glycol* and 2-Methoxyethanol) – Glycol compounds are a class of organic compounds belonging to the alcohol family. Exposure to large amounts of ethylene glycol can damage the kidneys, nervous system, lungs, and heart. Exposure to high concentrations of 2-methoxyethanol is associated with testicular damage, impaired nervous system, and anemia. Glycols are known to be common in drilling fluids.
5. Manganese* – Manganese is a naturally occurring substance found in many types of rock and soil. Manganese is also known to be a constituent of some specialized drilling fluids. Eating a small amount of manganese from food or water is needed to stay healthy. At high levels, it can cause damage to the nervous system.

6. Phenol* - Phenol is both a manufactured chemical and a natural substance. Phenol is used as a disinfectant and is found in a number of consumer products. Skin exposure to high amounts can produce skin burns, liver damage, dark urine, and irregular heart beat. Various phenols are commonly associated with drilling fluids.
7. Sodium* – Sodium is an essential nutrient and occurs naturally in most foods. Excessive sodium intake is associated with high blood pressure. Various sodium containing compounds are associated with drilling fluids.

*A hazardous substance, as defined under CERCLA Section 101(14) and designated in Section 302.4 of the National Contingency Plan (NCP), 40 C.F.R. Section 302.4.

B. National Priorities List

The Dimock Residential Groundwater Site is not on the CERCLA National Priorities List (NPL).

C. State and Local Authorities' Roles

Cabot had been sampling the home wells and providing bottled drinking water and alternate water for non-potable use, through a Consent Order and Agreement (CO&A) with PADEP. The CO&A applies only to a specific list of homes, and does not include other homes, also located within the same geographic area. Some of these additional homes have had limited sampling conducted by Cabot and/or PADEP. PADEP determined that Cabot has complied with the terms of the CO&A, as it applies to the provision of temporary water, and subsequently approved Cabot's request to stop the delivery of alternate water.

IV. THREATS TO PUBLIC HEALTH OR WELFARE OR THE ENVIRONMENT

Section 300.415 of the NCP lists the factors to be considered in determining the appropriateness of a Removal Action. Paragraphs (b)(2)(i), (ii), and (vii) of Section 300.415 directly apply to the conditions found at the Dimock Residential Groundwater Site.

In evaluating the situation, the OSC first considered whether hazardous substances were present in a home well. The levels of those hazardous substances were then considered against primary Maximum Contaminant Levels (MCLs). They were also considered for non-cancer risk to determine if the levels generate a hazard quotient greater than 2. The presence of inorganic and organic chemicals in a number of wells supports the need for this action.

300.415 (b)(2)(i) "Actual or potential exposure to nearby human populations, animals or the food chain from hazardous substances or pollutants or contaminants"

The hazardous substances listed above, present in water from home wells at this Site based on sampling data described below, could cause adverse health impacts when chronic exposure through drinking water or other uses of water in the home occurs. There are other contaminants discussed in the Agency for Toxic Substances and Disease Registry's (ATSDR) Record of Activity (AROA) issued on December 28, 2011, which could also cause adverse health impacts. ATSDR has concluded for the area originally included with the PADEP/Cabot CO&A, which includes the four homes being considered here for alternate water, that a chronic health risk exists for most wells and that the situation supports a "Do Not Use the Water" action including the consideration of alternative home water supplies until further characterization is completed. An EPA Region III toxicologist's opinion is that, of the homes evaluated to date in an on-going effort, that four home wells contain contaminants at levels that present a public health concern. In one home, manganese was detected at 628 ug/L. Exposure to this concentration would yield a Hazard Quotient of approximately 2. In another home, manganese (1360 ug/L) was detected at a level that generates a Hazard Quotient of approximately 4. Note that children reside at this location. In the third home, arsenic was observed at a concentration (37 ug/L) that exceeds its MCL of (10 ug/L) and would pose a long-term cancer risk of 8E-04. Note that children reside at this location. In the fourth home, manganese was detected at 669 ug/L. Exposure to this concentration would yield a Hazard Quotient of approximately 2.3. Available data also indicate that hazardous substances may be present in a number of other homes. Because the available data is not complete and is of uncertain quality, additional sampling is needed to facilitate a further evaluation of any potential health concerns from the drinking water at home wells in the Site area.

EPA is providing water based upon a risk of exposure to hazardous substances above health-based levels. Furthermore, the OSC notes that for those homes where the EPA toxicologist has not identified contaminants that present a public health concern, that the limited data available does identify the existence of hazardous substances. In addition, PADEP's CO&A determined that 18 home wells were impacted by drilling activities; such impact may be evidence of the migration of hazardous substances.

Again, it is noted that this determination is based upon data which was collected by parties other than EPA (Cabot and PADEP). The quality assurance/quality control (QA/QC) information has not been verified. However, what is clear is that this data strongly suggests that hazardous substances have been released and are present in some home wells at levels that may present a public health concern. Current data does show arsenic and manganese at higher levels than may be typically found, in post drilling samples. Since arsenic and manganese are naturally occurring substances, EPA's assessment will include comparisons of background concentrations and post drilling concentrations present. EPA routinely acts under CERCLA to protect public health first while it acts to further define contamination. Thus, within this action, EPA will complete an assessment of the water quality of the home wells in the Site area to close information gaps as soon as possible. This sampling will be focused initially on evaluating those homes in the Site area that have been sampled in the past. Beyond that, sampling at homes will be based upon a sampling rationale using information regarding alleged health impacts and data gaps. In addition, EPA will continue to evaluate the updated data, and may revise its actions to provide water to any of the additional homes, or to cease provision of water, as warranted by the data.

300.415 (b)(2)(ii) "Actual or potential contamination of drinking water supplies or sensitive ecosystems"

The discussion of 300.415 (b) (2) (i) above applies to this factor. Both organic and inorganic contaminants have been detected in home wells. Although this action is predominantly based upon inorganic data at the four homes, it should be noted that organic compounds have been detected at other homes as detailed in the ATSDR AROA. Glycol detections included ethylene glycol, triethylene glycol, and 2,2'oxybisethanol (diethylene glycol). Some wells had all three reported glycols present in their wells but no exceedances of risk based screening criteria (note: the analytical detection level used appeared to be higher than screening levels). Bis(2-ethylhexyl) phthalate (DEHP) was detected in five samples and ranged from 0.14 µg/L to 22 ug/L. 2-methoxyethanol concentrations (ranging from 880 ug/L to 1,300 ug/L) were detected in each of six wells.

300.415 (b) (2) (vii) "The availability of other appropriate federal or state response mechanisms to respond to the release"

The four homes being considered for alternate water under this action were all dependent upon donated water, either bottled, water buffaloes (temporary storage tanks) or both. It is the OSC's understanding that the last delivery of bulk water from those organizations ceased on January 3, 2012. In any case the reliability of sources for donated water is at best uncertain.

V. PROPOSED ACTIONS AND ESTIMATED COSTS

A. Proposed Action

1. Proposed Action Description

Throughout the duration of Site activities, all personnel involved with execution of this proposed action will comply with the requirements of CERCLA and with all other applicable Federal and State regulations to the extent practicable considering the exigencies of the situation in accordance with 40 CFR § 300.415(j). Available data indicate that a number of homes in the area have hazardous substances present in the home wells, but only four indicate concentrations identified by the EPA toxicologist at a level of concern. Thus, those four homes will be immediately supplied with water. At the same time, approximately 61 home wells will be sampled by EPA to obtain data of known quality assurance to support future evaluations and response decisions. EPA will continue to evaluate the updated data, and may revise its actions to provide water to any of the additional homes, or to cease provision of water, as warranted by the data. The Removal activities at the Site will include the following:

1. Mobilize and demobilize personnel and equipment to conduct the action;
2. Delivery of a temporary source of clean water for household use to the four (4) homes with wells that contain contaminants at levels of public health concern. This provision of temporary water will continue until potential exposures are further understood and mitigated as needed.
3. The sampling program will include analysis for a broad range of parameters with a special priority being placed on quick turnaround for those parameters which are most frequently observed in the data available to EPA at this time. The Agency will also do some limited sampling for methane and bacteriological constituents. Home well water sampling will be performed by EPA in the Site area using the following assigned priority:

    i. The four (4) homes considered for provision of alternate water, to assess the potential exposure to hazardous substances and to determine whether continued temporary provision of clean water for household use is required.
    ii. The seventeen (17) remaining homes located on properties included in the PADEP/Cabot CO&A[2], which were identified as being impacted by drilling activities.
    iii. Approximately thirty (30) additional homes in the immediate area that have been sampled in the past.
    iv. Additional homes in the Site area where one or more of the factors below supports sampling.
        1. Direct observation or other evidence (home well surveys) of adverse health effects potentially attributable to contaminated groundwater use.
        2. Where data gaps in groundwater measurement or sampling need to be filled to gain an adequate understanding of Site conditions.

    Approximately ten (10) homes are currently identified from well surveys, but more could be added based upon data review.
4. Maintain necessary documentation of Site activities.
5. Develop and implement appropriate health and safety protocols for the removal activity.

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[2] It had originally been reported that 19 homes were served by the 18 wells included within the scope of the CO&A but the door-to-door home well survey conducted to date by EPA has identified that there are currently 21 homes served by 20 wells on those same properties.

2. Contribution to Remedial Performance

A remedial action is not anticipated and therefore this removal action is not inconsistent with any proposed remedial action.

3. Applicable or Relevant and Appropriate Requirements ("ARARs")

Actions will be conducted in compliance with Applicable or Relevant and Appropriate Regulations (ARARs) to the extent practicable considering the exigencies of the situation, in accordance with 40 CFR 300.415(j).

B. Estimated Costs

Extramural Costs	Total
Regional Allowance Costs: (ERRs Contractors and Subcontractors)	$ 50,000
Other Extramural Costs Not Funded From the Regional Allowance: START Contractor	$ 25,000
Subtotal, Extramural	$ 75,000
Extramural Costs Contingency	$ 25,000
Total Removal Action Project Ceiling	**$100,000**

VI. EXPECTED CHANGE IN SITUATION SHOULD ACTION BE DELAYED OR NOT TAKEN

If no action is taken, the residents may utilize well water which poses a potential public health concern.

VII. OUTSTANDING POLICY ISSUES

Because this response action could be considered nationally significant or precedent setting, it requires the prior concurrence of the Assistant Administrator, Office of Solid Waste and Emergency Response (AA-OSWER). Furthermore, because the action appears to be nationally significant and/or precedent-setting, the Region will continue to coordinate closely with Headquarters. EPA also will maintain coordination and communications with PADEP. In taking this action, EPA is aware of and has considered the potential applicability of the natural gas exclusion under CERCLA, the Bentsen Amendment under the Resource Conservation and Recovery Act (RCRA), and the exclusions to the definition of 'underground injection' under the Safe Drinking Water Act (SDWA). EPA has concluded that this action is appropriate under CERCLA at this time.

VIII. ENFORCEMENT

The total EPA costs for this removal action based upon full-cost accounting practices that will be eligible for cost recovery are estimated below as follows:[3]

Direct Extramural Costs	$100,000
Direct Intramural Costs	$ 25,000
Total Direct Costs	$125,000
Indirect Cost (67.13% x Direct Costs)	$ 83,912
Total Costs (Direct and Indirect)	$208,912

IX. RECOMMENDATION

This Action Memorandum represents the selected Removal Action for the Dimock Residential Groundwater Site in Dimock Township, Susquehanna County, Pennsylvania, developed in accordance with CERCLA, as amended, and is consistent with the NCP. This decision is based on the administrative record for the Site. The administrative record consists of the following documents

1. 1/13/12 "Dimock Home Well Data" memo from EPA Toxicologist Dawn Ioven.
2. ATSDR AROA Issued 12/28/11.
3. Summary of Portions of data received by EPA and reviewed by the OSC.
4. PADEP Consent Order and Agreement, dated December 15, 2010.
5. EPA Data Review Memo, January 13, 2012.
6. EPA 104e request to Cabot, January 6, 2012

Conditions at the Site meet the Removal Action requirements of Section 300.415(b) of the NCP and I recommend your approval of the proposed removal action and exemption from the statutory limits. The total project ceiling, if approved, will be $100,000. Of this, as much as, $50,000 comes from the Regional removal allowance. Please indicate your approval or disapproval below.

[3] Direct Costs include direct extramural costs and direct intramural costs. Indirect costs are calculated based on an estimated indirect cost rate expressed as a percentage of site-specific direct costs, consistent with the full cost accounting methodology effective October 2, 2000. These estimates do not include pre-judgment interest, do not take into account other enforcement costs, including Department of Justice costs, and may be adjusted during the course of a removal action. The estimates are for illustrative purposes only and their use in not intended to create any rights for responsible parties. Neither the lack of a total cost estimate nor deviation of actual total costs from this estimate will affect the United States' right to cost recovery.

Action by the Approving Official:

I have reviewed the above-stated facts and, based upon those facts and the information compiled in the documents described above, I hereby approve/disapprove the selected removal action.

APPROVED: Dennis P Carney __________________ **DATE** 1/19/2012
Dennis P. Carney, Associate Division Director
Hazardous Site Cleanup Division
EPA Region 3

DISAPPROVED: __________________________ **DATE** ______________
Dennis P. Carney, Associate Division Director
Hazardous Site Cleanup Division
EPA Region 3

EPA United States Environmental Protection Agency

Newsroom

News Releases By Date

EPA Completes Drinking Water Sampling in Dimock, Pa.

Release Date: 07/25/2012
Contact Information: Terri White white.terri-a@epa.gov (215) 814-5567

PHILADELPHIA (July 25, 2012) – The U.S. Environmental Protection Agency announced today that it has completed its sampling of private drinking water wells in Dimock, Pa. Data previously supplied to the agency by residents, the Pennsylvania Department of Environmental Protection and Cabot Oil and Gas Exploration had indicated the potential for elevated levels of water contaminants in wells, and following requests by residents EPA took steps to sample water in the area to ensure there were not elevated levels of contaminants. Based on the outcome of that sampling, EPA has determined that there are not levels of contaminants present that would require additional action by the Agency.

"Our goal was to provide the Dimock community with complete and reliable information about the presence of contaminants in their drinking water and to determine whether further action was warranted to protect public health," said EPA Regional Administrator Shawn M. Garvin. "The sampling and an evaluation of the particular circumstances at each home did not indicate levels of contaminants that would give EPA reason to take further action. Throughout EPA's work in Dimock, the Agency has used the best available scientific data to provide clarity to Dimock residents and address their concerns about the safety of their drinking water."

EPA visited Dimock, Pa. in late 2011, surveyed residents regarding their private wells and reviewed hundreds of pages of drinking water data supplied to the agency by Dimock residents, the Pennsylvania Department of Environmental Protection and Cabot. Because data for some homes showed elevated contaminant levels and several residents expressed concern about their drinking water, EPA determined that well sampling was necessary to gather additional data and evaluate whether residents had access to safe drinking water.

Between January and June 2012, EPA sampled private drinking water wells serving 64 homes, including two rounds of sampling at four wells where EPA was delivering temporary water supplies as a precautionary step in response to prior data indicating the well water contained levels of contaminants that pose a health concern. At one of those wells EPA did find an elevated level of manganese in untreated well water. The two residences serviced by the well each have water treatment systems that can reduce manganese to levels that do not present a health concern.

As a result of the two rounds of sampling at these four wells, EPA has determined that it is no longer necessary to provide residents with alternative water. EPA is working with residents on the schedule to disconnect the alternate water sources provided by EPA.

Overall during the sampling in Dimock, EPA found hazardous substances, specifically arsenic, barium or manganese, all of which are also naturally occurring substances, in well water at five homes at levels that could present a health concern. In all cases the residents have now or will have their own treatment systems that can reduce concentrations of those hazardous substances to acceptable levels at the tap. EPA has provided the residents with all of their sampling results and has no further plans to conduct additional drinking water sampling in Dimock.

For more information on the results of sampling, visit: http://www.epa.gov/aboutepa/states/pa.html .

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NATURAL RESOURCES DEFENSE COUNCIL

September 8, 2010

By FedEx and e-mail

The Honorable Lisa Jackson
Administrator
United States Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Petition for Rulemaking Pursuant to Section 6974(a) of the Resource Conservation and Recovery Act Concerning the Regulation of Wastes Associated with the Exploration, Development, or Production of Crude Oil or Natural Gas or Geothermal Energy.

Dear Administrator Jackson:

To best protect human health, food sources, and our environment from the toxicity of contaminants found in wastes associated with the exploration, development and production of oil, gas, and geothermal energy, we believe it is appropriate for the Environmental Protection Agency (EPA) to reconsider its 1988 Regulatory Determination and regulate these wastes under Subtitle C of the Resource Conservation and Recovery Act (RCRA). The Natural Resources Defense Council (Petitioner) is submitting the attached rulemaking petition pursuant to Section 6974(a) of RCRA, 42 U.S.C. § 6974(a). In support of this petition, we identify numerous reports and data produced since the EPA's Regulatory Determination for Oil, Gas, and Geothermal Exploration, Development, and Production Wastes (July 6, 1988) which quantify the waste's toxicity, threats to human health and the environment, inadequate state regulatory programs, and readily available solutions.

The Natural Resources Defense Council (NRDC) is a nonprofit environmental action group established in 1970 by a group of law students and attorneys at the forefront of the environmental movement. The Natural Resources Defense Council's purpose is to safeguard the Earth: its people, its plants and animals and the natural systems on which all life depends. NRDC uses law, science and the support of 1.2 million members and online activists to protect the planet's wildlife and wild places and to ensure a safe and healthy environment for all living things. NRDC has worked for many years to ensure the proper regulation of oil and gas exploration and production operations.

Section 6974(a) of RCRA allows any person to petition the Administrator of the EPA to promulgate an environmental regulation. Within a reasonable time following receipt of such petition, the Administrator shall take action with respect to such petition and shall publish notice of such action in the Federal Register, together with the reasons therefor. This petition asks the EPA to take specific actions and directs the EPA's attention to the ample documentation in the record, which provides full support for the designation of wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy as hazardous waste under RCRA and provides a firm and compelling basis for the reconsideration of the EPA's July 1998 Regulatory Determination.

Thank you in advance for your consideration of this petition.

Respectfully submitted by:

Amy Mall

Amy Mall
Senior Policy Analyst

Diane Donnelly
Legal Intern

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I. THE EPA SHOULD REGULATE WASTE FROM THE EXPLORATION, DEVELOPMENT AND PRODUCTION OF CRUDE OIL AND NATURAL GAS UNDER SUBTITLE C OF RCRA.

We request that the U.S. Environmental Protection Agency (EPA) promulgate regulations that subject wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy to the hazardous waste provisions of Subtitle C of the Resource Conservation and Recovery Act (RCRA). We submit this petition pursuant to 42 U.S.C. § 6974(a), seeking that EPA ensure safe management of these wastes throughout their life cycle from cradle to grave, including generation, transportation, treatment, storage and disposal. Reports concerning the toxicity of exploration, development and production wastes, their release into the environment, threats to human health, the increasing amount of these types of wastes being generated, the inadequacy of existing state regulations, enforcement and oversight, and the feasibility and economic benefits of using disposal techniques that are less harmful to the environment all support regulation under Subtitle C, as described in detail below.

A. The EPA Has Authority to Reconsider Its 1988 Regulatory Determination.

Congress gave EPA the authority to prescribe necessary regulations to carry out its functions under RCRA.[1] Congress charged EPA with the task of "assuring that hazardous waste management practices are conducted in a manner which protects human health and the environment."[2] Congress ensured that the public had a way to seek additional protections from hazardous wastes by allowing "[a]ny person . . . [to] petition the Administrator for the promulgation, amendment, or repeal of any regulation under" RCRA, and by requiring that "[w]ithin a reasonable time following receipt of such petition, the Administrator shall take action with respect to such petition and shall publish notice of such action in the Federal Register, together with the reasons therefor."[3]

With these provisions, Congress expressed its intent that RCRA would adapt to changing hazardous waste management needs. Foreseeing the need to update regulations promulgated under RCRA to account for changing circumstances,[4] Congress provided the public a way to bring about EPA review of its regulations.[5] These provisions authorize EPA to reconsider its current treatment of wastes associated with the exploration, development, or production of oil and gas (E&P wastes).

[1] 42 U.S.C. § 6912(a)(1).
[2] 42 U.S.C. § 6902(a)(4).
[3] 42 U.S.C. § 6912(a)(1).
[4] 42 U.S.C. § 6912(b).
[5] 42 U.S.C. § 6912(a)(1).

Congress passed RCRA in 1976 as an amendment to the Solid Waste Disposal Act of 1965 in an effort to enact more comprehensive waste disposal standards nationwide.[6] Through RCRA, Congress declared that the "disposal of solid waste . . . without careful planning and management [was] a danger to human health and the environment."[7] Congress later amended RCRA with the Solid Waste Disposal Act Amendments of 1980.[8] One of the 1980 amendments, the so-called Bentsen Amendment, temporarily exempted "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas" from regulation under RCRA.[9]

Under the Bentsen Amendment, Congress directed EPA to conduct a study to determine whether or not E&P wastes should be regulated as hazardous wastes under RCRA.[10] EPA completed the required study and submitted a Report to Congress on the Management of Waste from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy.[11] Shortly after submitting its report to Congress, EPA issued its Regulatory Determination for Oil, Gas, and Geothermal Exploration, Development, and Production Wastes, in which it decided that regulation of E&P wastes under Subtitle C of RCRA was unwarranted.[12]

In the more than twenty years that have passed since EPA issued its Regulatory Determination on E&P wastes, both the oil and gas industry and the risks associated with E&P wastes have expanded dramatically, making EPA's 1988 Regulatory Determination unjustified. While E&P wastes have always been hazardous to human health and the environment, the recent expansion of drilling operations to more densely populated areas places even more people at risk. EPA's reconsideration of its 1988 Regulatory Determination is especially necessary now that the basis for its Regulatory Determination no longer reflects current conditions. In its 1988 Regulatory Determination, EPA identified three factors as the basis for its decision not to regulate E&P wastes under Subtitle C. These factors included: (1) the infeasibility of implementing alternative regulations, (2) the adequacy of state regulations, and (3) the economic harm that would befall the oil and gas industry if additional regulatory controls were imposed.[13]

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[6] Joseph F. Scavetta, *RCRA 101: A Course in Compliance for Colleges and Universities*, 72 NOTRE DAME L. REV. 1647 (1997).
[7] Natasha Ernst, Note, *Flow Control Ordinances in a Post*-Carbone *World*, 13 PENN ST. ENVTL. L. REV. 53 (2004) (citing 42 U.S.C §§ 6901–6992k (2003)).
[8] Pub. L. 96-482; *see also* James R. Cox, *Revisiting RCRA'S Oilfield Waste Exemption as to Certain Hazardous Oilfield Exploration and Production Wastes*, 14 VILL. ENVTL. L.J. 1, 3 (2003).
[9] 42 U.S.C. § 6921(b)(2)(A).
[10] 42 U.S.C. § 6921(b)(2)(B).
[11] EPA, REPORT TO CONGRESS, MANAGEMENT OF WASTES FROM THE EXPLORATION, DEVELOPMENT, AND PRODUCTION OF CRUDE OIL, NATURAL GAS, AND GEOTHERMAL ENERGY, Vols. 1–3 EPA530-SW-88-003 (1987) [hereinafter REPORT TO CONGRESS].
[12] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. 25446, 25447 (July 6, 1988).
[13] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 25446.

As will be discussed at greater length below, new evidence clearly demonstrates that alternative disposal practices are feasible, state regulations remain inadequate, and the oil and gas industry is unlikely to be severely harmed by the imposition of more stringent waste disposal requirements. Because this evidence shows that the assumptions on which EPA's 1988 Regulatory Determination was based are no longer correct, EPA must revisit its decision.[14]

Nothing in RCRA prevents the EPA from reconsidering its 1988 Regulatory Determination. In *American Portland Cement Alliance*,[15] the court upheld EPA's authority to reconsider regulatory determinations made pursuant to the 1980 amendments to RCRA.[16] Moreover, statements made by EPA in its 1988 Regulatory Determination indicate that EPA never intended the Regulatory Determination to be its final word on E&P waste. Instead, EPA established a three-pronged plan and intended to take further action to fill in existing gaps in the regulations governing the disposal of E&P wastes.[17] To date this three-pronged plan has not been fulfilled. Gaps in the regulatory system governing E&P wastes have grown even wider and evidence of the substantial harm E&P wastes can cause to human health and the environment has continued to accumulate. EPA must revisit its 1988 Regulatory Determination to fulfill its obligations under the 1988 Regulatory Determination and protect human health and the environment from the significant risks posed by E&P wastes.

Unless EPA revisits its 1988 Regulatory Determination and recommends that E&P wastes be regulated under Subtitle C of RCRA, E&P wastes will continue to present substantial hazards to human health and the environment.[18]

B. EPA Should Regulate E&P Wastes Under Subtitle C of RCRA.

In light of the documented toxicity of contaminants found in E&P waste, the failure of states to adequately regulate the disposal of E&P wastes, the dramatic increase in oil and gas production that has occurred since 1988, and the availability of safer cost-effective disposal alternatives, EPA must take action in order to prevent further harm to human health and the

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[14] EPA Region 8 itself stated that "EPA may need to revisit the continued validity of the exemption in light of the advancements in practices." EPA REGION 8, AN ASSESSMENT OF THE ENVIRONMENTAL IMPLICATIONS OF OIL AND GAS PRODUCTION: A REGIONAL CASE STUDY 3-14 (Working Draft 2008).
[15] 101 F.3d 772 (D.C. Cir. 1996).
[16] *Id.*
[17] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 25,447.
[18] [This footnote intentionally deleted in corrected copy.]

environment. EPA should reconsider its 1988 Regulatory Determination and regulate E&P wastes under Subtitle C of RCRA. Regulation under Subtitle C is not only appropriate, given that E&P wastes fall within the regulatory criteria for characteristic hazardous waste,[19] but necessary because, without such action, the oil and gas industry will lack the incentives to implement safer techniques as quickly as is necessary.[20]

1. E&P Waste Is Toxic.

E&P waste that is exempt from regulation under Subtitle C includes: drilling fluids and cuttings, produced water, used hydraulic fracturing fluids, rigwash, workover wastes, tank bottom sludge, glycol-based dehydration wastes, amine-containing sweetening wastes, hydrocarbon-bearing soil, and many other individual waste products.[21] In its 1988 Regulatory Determination, EPA admitted that E&P wastes contain toxic substances that endanger both human health and the environment.[22] Despite noting that benzene, phenanthrene, lead, arsenic, barium, antimony, fluoride, and uranium found in E&P wastes were of major concern and present at "levels that exceed 100 times EPA's health based standards,"[23] EPA declined to regulate these toxic substances under Subtitle C of RCRA. But EPA can no longer refuse to act: an ever-increasing amount of evidence demonstrates that E&P wastes are toxic, have had substantial negative effects on human health and the environment, and should be a major concern for EPA. Since 1988, numerous reports, studies, and cases have demonstrated that E&P wastes contain toxic substances that threaten both human health and the environment.

a. Contaminants Found in Different Types of E&P Wastes

E&P wastes are generally divided into three categories: produced water, drilling fluids and cuttings, and associated wastes.[24] All of these wastes contain a variety of toxic substances that present substantial risks to human health and the environment. Despite these risks, these E&P wastes are currently exempt from regulation under Subtitle C.

[19] *See* notes 282–313 *infra* and accompanying text.
[20] Closing Argument of the New Mexico Citizens for Clean Air and Water, Dec. 2007, OCD Document Image No. 14015_648_CF[1] at 9-10; *see also* AMY MALL, DRILLING DOWN: PROTECTING WESTERN COMMUNITIES FROM THE HEALTH AND ENVIRONMENTAL EFFECTS OF OIL AND GAS PRODUCTION vi (2007) [hereinafter "DRILLING DOWN"].
[21] *See* RAILROAD COMMISSION OF TEXAS, *Hazardous and Nonhazardous Oil and Gas Waste* 3–6, *in* WASTE MINIMIZATION IN THE OIL FIELD (2001).
[22] Regulatory Determination for Oil and Gas and Geothermal Exploration, Development and Production Wastes, 53 Fed. Reg. at 25448.
[23] *Id.*; *see also* Cox, *supra* note 8, at 9.
[24] CLAUDIA ZAGREAN NAGY, CALIFORNIA DEP'T OF TOXIC SUBSTANCES CONTROL, OIL EXPLORATION AND PRODUCTION WASTES INITIATIVE 6 (2002).

i. Produced Water & Hydraulic Fracturing Wastewater

Produced water, also known as brine, is generally—but erroneously—considered to be "relatively clean" and contain less contaminants than other E&P waste.[25] Despite this common misconception, a study sponsored by the U.S. Department of Energy demonstrated that oil production yields "environmentally hazardous" produced water.[26] The West Virginia Department of Environmental Protection (WVDEP) found many contaminants of concern present in oil and gas wastewaters,[27] including arsenic, lead, and hexavalent chromium, while EPA Region 8 identified the presence of barium, chloride, sodium, sulfates, and other minerals,[28] and the Oklahoma Corporation Commission Oil and Gas Conservation Division stated that produced water can contain high levels of boron.[29] In 2009, the Colorado Oil and Gas Conservation Commission (COCG) documented multiple spills of produced water containing benzene levels exceeding the state's water quality standards, at least one of which was confirmed to have impacted groundwater.[30]

Knowledge of the hazardous nature of produced water is not new. In 1972, Chevron Oil Field Research Company found that "oil field produced waters contain dissolved organic compounds that are toxic to marine life."[31] More than a decade later, the U.S. General Accounting Office (GAO) acknowledged that "[b]rines associated with oil and gas production contain very high levels of chlorides . . . . Brines may also contain . . . petroleum hydrocarbons and additives, such as corrosion inhibitors, . . . and other radioactive materials."[32] EPA was aware of these hazardous constituents when it issued its 1988 Regulatory Determination. In its 1987 Report to Congress, EPA knew that "PAHs [polycyclic aromatic hydrocarbons] are a typical component of some produced waters," that "very low concentrations . . . of PAH are lethal to some forms of aquatic wildlife," and that the practice of disposing of "produced water in

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[25] KELLY CORCORAN, KATHERINE JOSEPH, ELIZABETH LAPOSATA, & ERIC SCOT, UC HASTINGS COLLEGE OF THE LAW'S PUBLIC LAW RESEARCH INSTITUTE, SELECTED TOPICS IN STATE AND LOCAL REGULATION OF OIL AND GAS EXPLORATION AND PRODUCTION 31–32.

[26] C. TSOURIS, OAK RIDGE NATIONAL LABORATORY, EMERGING APPLICATIONS OF GAS HYDRATES 7.

[27] The contaminants of concern included: "sulfate, chloride, arsenic, titanium, cobalt, nickel, silver, zinc, vanadium, tin, cadmium, lead, chromium, hexavalent chromium, copper, fluoranthene, cyanide, mercury, selenium, antimony, beryllium, barium, ammonia nitrogen, fluoride, nitrite nitrogen, nitrate nitrogen, oil and grease, total suspended solids, iron, aluminum, chloroform, benzene, phthalate esters, strontium, strontium-90, boron, lithium, gross alpha radiation, gross beta radiation, radium 226+ [and] radium 228." Letter from West Virginia Department of Environmental Protection to William Goodwin, Superintendent Clarksburg Sanitary Board, July 23, 2009.

[28] EPA REGION 8, AN ASSESSMENT OF THE ENVIRONMENTAL IMPLICATIONS OF OIL AND GAS PRODUCTION: A REGIONAL CASE STUDY, WORKING DRAFT 3-11 (2008).

[29] OKLAHOMA CORPORATION COMMISSION OIL AND GAS CONSERVATION DIVISION, GUIDELINES FOR RESPONDING TO AND REMEDIATING NEW OR HISTORIC BRINE SPILLS 2 (2009).

[30] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1631502, 1631508 (groundwater impact confirmed).

[31] A.H. BEYER, CHEVRON OIL FIELD RESEARCH CO., TECHNICAL MEMORANDUM, PURIFICATION OF PRODUCED WATER, PART 1—REMOVAL OF VOLATILE DISSOLVED OIL BY STRIPPING 1 (1972).

[32] U.S. GENERAL ACCOUNTING OFFICE, RCED-89-97, SAFEGUARDS ARE NOT PREVENTING CONTAMINATION FROM INJECTED OIL AND GAS WELLS 11 (1989).

unlined percolation pits [allows] PAHs and other constituents to migrate into and accumulate in soils."[33]

In addition to containing dangerous contaminants, produced water can also be radioactive. This problem first attracted national attention 1988 in southern and Gulf Coast states.[34] Shortly thereafter, GAO's 1989 report openly acknowledged the hazard.[35] A more recent analysis of normally occurring radioactive materials (NORM) levels in produced waters from the Marcellus Shale indicates that the dangers may be greater than initially thought.[36] Samples of produced water in the Marcellus Shale analyzed by the New York State Department of Environmental Conservation (NYSDEC) were reported to contain "levels of radium 226, a derivative of uranium, as high as 267 times the limit safe for people to drink."[37]

Despite knowledge of these risks, the data currently available may underestimate the actual radiation levels in produced water. A common method used by industry and EPA to measure radiation levels in produced water has been criticized because of its tendency to underestimate actual radiation levels. In the late 1980s, Exxon Mobil, along with Rogers and Associates Engineers (RAE) and the American Petroleum Institute (API), formulated correlations that could be used to estimate NORM in levels of equipment used to hold produced water.[38] The external measurement process chosen by RAE to measure the NORM levels has since been challenged as "seriously flawed" and has resulted in the reporting of a "greatly reduced radioactivity concentration of 480 pCi/gm."[39] Accurate testing could reveal that the NORM levels in produced water are even higher than currently being reported.

Wastewaters from hydraulic fracturing, largely composed of used fracturing fluids, are also toxic. Common substances found in these wastewaters include: surfactants, friction reducing chemicals, biocides, scale inhibitors, polymers, cross linkers, pH control agents, gel breakers, clay control agents and propping agents.[40] Many of these substances are possible and probable carcinogens.[41] Analysis of fracturing fluid flowback waters from Pennsylvania and West Virginia found the known carcinogen benzene present in nearly half of all fracturing fluid flowback waters at average concentrations nearly one hundred times the maximum acceptable

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[33] EPA, REPORT TO CONGRESS, *supra* note 11, at II-44.
[34] Keith Schneider, *Radiation Danger Found in Oilfields Across the Nation*, N.Y. TIMES, Dec. 3, 1990, at A1.
[35] GAO, RCED-89-97, *supra* note 32.
[36] N.Y. DEP'T OF ENVTL. CONSERVATION, DRAFT SUPPLEMENTAL GENERIC ENVIRONMENTAL IMPACT STATEMENT ON THE OIL, GAS AND SOLUTION MINING REGULATORY PROGRAM 6-130 (2009) [hereinafter DRAFT SGEIS].
[37] Abrahm Lustgarten, ProPublica, *Natural Gas Drilling Produces Radioactive Wastewater*, SCIENTIFIC AMERICAN, Nov. 9, 2009; *see also* DRAFT SGEIS, *supra* note 36, at app. 13.
[38] Motion in Limine to Exclude Rogers and Associates Engineering Reports, Lester v. Exxon Mobil Corp., No. 630-402 (La. 24th Jud. Dist. Ct. 2009), at 6–7.
[39] *Id.* at 7-8.
[40] Wilma Subra, Louisiana Environmental Action Network, Comments on Hydraulic Fracturing to the Louisiana Senate Environmental Quality Committee, Mar. 11, 2010.
[41] *Id.*

contaminant levels established by EPA.[42] While this information demonstrates that these wastes contain toxic compounds, the true extent of the risks associated with hydraulic fracturing wastewaters is currently unknown as many of the compounds used in fracturing fluids and returned in the wastewaters are not publically disclosed.[43]

ii. Drilling Fluids and Drill Cuttings

Drilling fluids and cuttings make up two to four percent of oil and gas wastes.[44] They include rock removed during drilling (drill cuttings) and drilling muds, also known as drilling fluids, which can be either water or oil-based and often contain various additives.[45] A joint EPA/API survey found drilling fluids in reserve pits to contain "chromium, lead and pentachlorophenol at hazardous levels."[46] The survey also found that "oil-based fluids may contain benzene"[47] and that when oil-based fluids are used, "potentially toxic hydrocarbons" will be present in greater quantities.[48] Drilling muds may also contain other "potentially hazardous substances including . . . cadmium, arsenic . . . mercury, copper . . . diesel oil; grease; and various other hydrocarbons and organic compounds (e.g., methanol, chlorinated phenols, formaldehyde, benzene, toluene, ethyl benzene, xylene, and acrylamide)," as well as additives including acids and caustics, corrosion inhibitors, bactericides and biocides, surfactants, defoamers, emulsifiers, filtrater

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42 Susan Riha et al, *Comments on the Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program*, Jan. 2010, at 5; *see also* N.Y. DEP'T OF ENVTL. CONSERVATION, DRAFT SGEIS 5-104 (2009).

43 Wilma Subra, Comments on Hydraulic Fracturing, *supra* note 40. *See also* DRAFT SGEIS, *supra* note 36, at 5-51 (stating that the fracturing fluid additives list "[c]hemical constituents are not linked to product names in Table 5.6 because a significant number of product composition and formulas have been justified as trade secrets as defined [under New York law] . . . .").

44 U.S. CONGRESS, OFFICE OF TECHNOLOGY ASSESSMENT, MANAGING INDUSTRIAL SOLID WASTES FROM MANUFACTURING, MINING, OIL AND GAS PRODUCTION, AND UTILITY COAL COMBUSTION—BACKGROUND PAPER 67 (1992).

45 *Id; see also* U.S. FISH & WILDLIFE SERV., REGION 6, ENVTL. CONTAMINANTS PROGRAM, RESERVE PIT MANAGEMENT: RISKS TO MIGRATORY BIRDS 4–5 (2009).

> "Water-based drilling muds can contain glycols, chromium, zinc, polypropylene glycol, and acrylamide copolymers. Synthetic-based muds contain mineral oil and oil-based muds can contain diesel oil, although diesel oil is being replaced by a palm oil derivative or hydrated caster [*sic*] oil. Other additives typically used in drilling fluids include: polymers (partially hydrolyzed polyacrylamide (PHPA) and polyanionic cellulose (PAC)); drilling detergents; and sodium carbonate (soda ash). PHPA is used to increase viscosity of fluid and inhibit clay and shale from swelling and sticking. PAC is used to increase the stability of the borehole in unconsolidated formations. Drilling detergents or surfactants are used with bentonite drilling fluids to decrease the surface tension of the drill cuttings. Soda ash is used to raise the pH of the water and precipitate calcium out of the water." *Id.* (internal citations omitted).

46 U.S. CONGRESS, OFFICE OF TECHNOLOGY ASSESSMENT, MANAGING INDUSTRIAL SOLID WASTES FROM MANUFACTURING, MINING, OIL AND GAS PRODUCTION, AND UTILITY COAL COMBUSTION—BACKGROUND PAPER 5 (1992).

47 *Id.*

48 OIL & GAS ACCOUNTABILITY PROJECT, PIT POLLUTION—BACKGROUNDER ON THE ISSUES, WITH A NEW MEXICO CASE STUDY 6 (2004).

reducers, shale control inhibitors, thinners and dispersants, weighing materials, bentonite clay, and acrylamide.[49]

The use of these additives increases the risks associated with E&P waste, as many are hazardous compounds themselves.[50] EPA has already classified at least one additive, flocculant acrylamide, as a probable carcinogen.[51] Another frequently used additive, barite weighting agent, can contain cadmium and mercury.[52] When Greenpeace analyzed the heavy metal contents of one drilling fluid additive, SOLTEX® (a scale inhibitor used in both on- and off-shore drilling muds), it identified the presence of antimony, arsenic, barium, cadmium, chromium, cobalt, copper, fluoride, lead, mercury, nickel, vanadium, and zinc.[53] These reports alone create cause for concern; yet, the full extent of the risk these chemicals present is unknown, as the additives' formulas, and thus the concentrations of the various chemicals, are proprietary information and undisclosed by oil and gas companies.[54]

iii. Associated Wastes

Associated wastes include oily sludges, workover wastes, well completion and abandonment wastes and other small volume wastes associated with oil or gas production.[55] Oily sludges consist of "oily sands and untreatable emulsions segregated from the production stream, and sediment accumulated on the bottom of crude oil and water storage tanks."[56] Workover wastes include foam treatment wastes and stimulation fluids.[57] Of all the E&P wastes, associated wastes are generated in the lowest volume;[58] however, this does not mean that they are safe or that current regulations ensure they are disposed of properly. Indeed, "[a]lthough associated wastes constitute a relatively small proportion of total wastes, they are most likely to contain a range of chemicals and naturally occurring materials that are of concern to health and safety."[59] Several associated wastes identified in Colorado have the "potential to be ignitable" while others "can exhibit toxicity for heavy metals such as lead."[60]

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[49] *Id.*
[50] *Id.*
[51] U.S. EPA, *Technology Transfer Air Toxics: Acrylamide*.
[52] T.A. Kassim, *Waste Minimization and Molecular Nanotechnology: Toward Total Environmental Sustainability*, *in* 3 ENVIRONMENTAL IMPACT ASSESSMENT OF RECYCLED WASTES ON SURFACE AND GROUND WATERS: ENGINEERING MODELING AND SUSTAINABILITY 191, 204 (Tarek A. Kassim ed., 2005); Texas Railroad Commission, Waste Minimization in Drilling Operations.
[53] JONATHAN WILLS, MUDDIED WATERS, A SURVEY OF OFFSHORE OILFIELD DRILLING WASTES AND DISPOSAL TECHNIQUES TO REDUCE THE ECOLOGICAL IMPACT OF SEA DUMPING (2000).
[54] OIL & GAS ACCOUNTABILITY PROJECT, *supra* note 48, at 6–7.
[55] NAGY, *supra* note 24, at 6.
[56] *Id. at* 13.
[57] *Id.* at 14.
[58] *Id. at* 6; American Petroleum Institute, Waste Management.
[59] Dara O'Rourke & Sarah Connolly, *Just Oil? The Distribution of Environmental and Social Impacts of Oil Production and Consumption*, 28 ANNUAL REV. ENVTL. RESOURCES 587, 595 (2003).
[60] Testimony of Margaret A. Ash, OGCC Envtl. Supervisor, *In the Matter of Changes to the Rules and Regulations of the Oil and Gas Conservation Commission of the State of Colorado*, at 15.

b. Contaminants Found in Specific E&P Waste Disposal Sites

The hazardous contaminants used in oil and gas exploration and production and whose presence has been identified in E&P wastes end up being disposed of in a variety of methods. Pits, burial, land application, and injection wells are the methods most frequently used to dispose of E&P wastes. Wastewater treatment facilities are also increasing in use. Studies of some of these different types of common E&P waste disposal sites provide further evidence of the toxicity of E&P wastes.

Pits are a common E&P waste disposal method used both to store drilling muds and cuttings brought to the surface in drilling operations and to hold produced water, production fluids, used hydraulic fracturing fluid, and other wastes.[61] Numerous studies have found pits to contain toxic levels of many hazardous compounds. In 2007, an industry committee of oil and gas companies in New Mexico sponsored a sampling and analysis program of waste pits in the San Juan Basin.[62] Forty-two substances, including the "BTEX" chemicals[63] (benzene, toluene, ethylbenzene, and xylene), acetone, arsenic, barium, mercury, and radium were found in the samples.[64] Eleven of the chemicals were present at concentration levels above state limits.[65] A more recent sampling of an oilfield pit in Texas identified the presence of high levels of mercury and chromium.[66] Dirt removed from a pit in Oklahoma was contaminated with "high levels of arsenic, dioxins and total petroleum hydrocarbons."[67]

Analysis of land application sites, another method for disposing of E&P wastes, provides further evidence illustrating the hazards of E&P wastes. A study of landfarms conducted by the Arkansas Department of Environmental Quality (ADEQ) found that the substances in E&P wastes that were being land applied exceeded Arkansas' acceptable limits for chloride concentrations in most of the facilities it tested.[68] In addition, "[n]ine out of eleven facilities had

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[61] CORCORAN ET AL., *supra* note 25, at 20–21.
[62] The Endocrine Disruption Exchange, Potential Health Effects of Residues in 6 New Mexico Oil and Gas Drilling Reserve Pits Based on Compounds Detected in at Least One Sample, Nov. 15, 2007.
[63] SHANNON D. WILLIAMS, DAVID E. LADD & JAMES J. FARMER, U.S. GEOLOGICAL SURVEY, FATE AND TRANSPORT OF PETROLEUM HYDROCARBONS IN SOIL AND GROUND WATER AT BIG SOUTH FORK NATIONAL RIVER AND RECREATION AREA, TENNESSEE AND KENTUCKY, 2002–2003 10 (2006) ("The BTEX compounds . . . appear on The Clean Water Act Priority Pollutant list of 126 chemical substances (Office of the Federal Register, 2002)."). Testing obtained by individuals residing near the pits has also confirmed the presence of dangerous contaminants. DRILLING DOWN, *supra* note 20, at 26 n.156.
[64] The Endocrine Disruption Exchange, *supra* note 62.
[65] The Endocrine Disruption Exchange, Number of Chemicals Detected in Reserve Pits for 6 Wells in New Mexico That Appear on National Toxic Chemicals Lists: Amended Document, Nov. 15, 2007.
[66] Letter from Roy Staiger, District Office Cleanup Coordinator, Texas Railroad Commission, to Exxon Mobil Corporation, Dec. 31, 2009.
[67] OIL & GAS ACCOUNTABILITY PROJECT, SPRING/SUMMER 2006 REPORT (2006).
[68] Arkansas Dep't of Envtl. Quality, Report on Landfarms ("Four facilities had pond chlorides greater than 3,000 mg/L and the ponds were full . . . . Eight out of eleven facilities had soil concentrations greater than 1,000 mg/Kg on at least one application area. Most were several times higher than 1,000 mg/Kg . . . .").

TPH concentrations that would indicate the application of [oil-based drilling fluids] had taken place."[69] Analysis of soil samples taken from a residential property in Texas, where pit sludge had been land applied less than 300 feet from a residence, "confirmed the presence of numerous hydrocarbons identified as Recognized and Suspected human carcinogens and neurotoxins (1, 2, 4 Trimethylbenzene, 1, 3, 5 Trimethylbenzene, 4-Isopropyltoluene, Acetone, Benzene, Carbon disulfide, Ethylbenzene, Isopropylbenzene, m&m Xylene, n-Butylbenzene, n-Propylbenzene, o-Xylene, sec-Butylbenzene, tert-Butylbenzene, Toluene)."[70] The residents of this property all reported skin rashes after the waste was applied to their land.[71]

c. The risks associated with these contaminants

i. Substances in E&P Wastes Endanger Human Health.

Many of these substances identified in E&P wastes are known carcinogens.[72] The most prevalent contaminants found in E&P wastes are the "BTEX" chemicals:[73] benzene,[74] toluene,[75] ethylbenzene,[76] and xylene.[77] Exposure to benzene has been "associated with an increased risk of leukemia in industrial workers"[78] and other serious health conditions, exposure to toluene can cause nervous system damage,[79] while xylenes can "cause dizziness, headaches and loss of balance among other problems."[80]Many of the other chemicals found in E&P waste, including

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[69] *Id.*

[70] WOLF EAGLE ENVIRONMENTAL, ENVIRONMENTAL STUDIES: FUGITIVE AIR EMISSIONS TESTING, IMPACTED SOIL TESTING, MR. AND MRS. TIMOTHY RUGGIERO (2010).

[71] Eric Griffey, *Toxic drilling waste is getting spread all over Texas farmland*, FORT WORTH WEEKLY, May 12, 2010.

[72] *See* Cox, *supra* note 8, at 4.

[73] CORCORAN ET AL., *supra* note 25, at 21.; *see also* WILLIAMS ET AL., *supra* note 63, at 10 ("The BTEX compounds . . . appear on The Clean Water Act Priority Pollutant list of 126 chemical substances (Office of the Federal Register, 2002)."); U.S.G.S., TOXIC SUBSTANCE HYDROLOGY PROGRAM: BTEX.

[74] "Benzene is a known human carcinogen and causes leukemia." DRILLING DOWN, *supra* note 20, at vi; *see also* WILLIAMS ET AL., *supra* note 63, at 26. ("Because of the high degree of toxicity and mobility of benzene (compared to other petroleum hydrocarbons), it is commonly the main ground-water contaminant of concern at petroleum release sites.").

[75] "Toluene can cause fatigue, confusion, weakness, memory loss, nausea, hearing loss, central nervous system damage, and may cause kidney damage. It is also known to cause birth defects and reproductive harm." DRILLING DOWN, *supra* note 20, at vi (footnotes omitted).

[76] "Ethylbenzene can cause dizziness, throat and eye irritation, respiratory problems, fatigue, and headaches. It has been linked to tumors and birth defects in animals, as well as to damage in the nervous system, liver, and kidneys." *Id.* (footnote omitted).

[77] "Xylene can cause headaches; dizziness; confusion; balance changes; irritation of the skin, eyes, nose and throat; breathing difficulty; memory difficulties; stomach discomfort; and possibly changes in the liver and kidneys." *Id.* (footnote omitted).

[78] N.Y. DEP'T OF ENVTL. CONSERVATION, *supra* note 36, at 5-62 (2009).

[79] CORCORAN ET AL., *supra* note 25, at 21.

[80] *Id.*

acetone,[81] arsenic,[82] barium,[83] mercury,[84] and radium,[85] all found in E&P waste samples, also raise serious concerns for human health.

The impacts of these contaminants have been documented. In a 1997 Louisiana case against U.S. Liquids & Exxon, plaintiffs reported that shortly after the dumping of more than fifty million gallons of E&P waste containing benzene, toluene, and lead occurred at a facility located less than 500 feet from the nearest resident's home, "[a] strange smell blew over the community and . . . . [m]any people in the area felt sick . . . . For nearly three weeks, most residents, including children, suffered from stomach pains, sinus problems and other ailments."[86] Other evidence demonstrates that exposure to contaminants in E&P wastes can result in delayed and long-term health effects. One study conducted in the Amazon Basin of Ecuador found that pregnant women who resided in areas where there was discharge of untreated oilfield wastes into the environment experienced higher levels of spontaneous abortion.[87] Another epidemiological study in the same area showed "significantly higher incidence of cancer for all sites combined in both men and women living in proximity to oil fields . . . . [specifically,] [s]ignificantly higher incidences were observed for cancers of the stomach, rectum skin melanoma, soft tissue and

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[81] Acetone can cause nose, throat, lung and eye irritation, respiratory problems, fatigue and headaches. *See* AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR ACETONE (1995); DRILLING DOWN, *supra* note 20, at vi (footnote omitted).

[82] "Chronic arsenic exposure can cause damage to blood vessels, a sensation of 'pins and needles' in hands and feet, darkening and thickening of the skin, and skin redness. It is a known human carcinogen and can cause cancer of the skin, lung, bladder, liver, kidney, and prostate." DRILLING DOWN, *supra* note 20, at vi (footnote omitted); *see also* AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR ARSENIC (2007) ("Exposure to lower levels can cause nausea and vomiting, decreased production of red and white blood cells, abnormal heart rhythm . . . ."); SCIENCELAB.COM, CHEMICALS & LABORATORY EQUIPMENT, MATERIAL SAFETY DATA SHEET: ARSENIC MSDS 1 (2008), ("[Arsenic is] toxic to kidneys, lungs, the nervous system, mucous membranes.")

[83] "Ingesting drinking water containing levels of barium above the EPA drinking water guidelines for relatively short periods of time can cause gastrointestinal disturbances and muscle weakness. Ingesting high levels for a long time can damage the kidneys . . . . Some people who eat or drink amounts of barium above background levels found in food and water for a short period may experience vomiting, abdominal cramps, diarrhea, difficulties in breathing, increased or decreased blood pressure, numbness around the face, and muscle weakness. Eating or drinking very large amounts of barium compounds that easily dissolve can cause changes in heart rhythm or paralysis and possibly death. Animals that drank barium over long periods had damage to the kidneys, decreases in body weight, and some died." AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR BARIUM (2007).

[84] "Mercury can permanently damage the brain, kidneys, and developing fetus and may result in tremors, changes in vision or hearing, and memory problems. Even in low does, mercury may affect an infant's development, delaying walking and talking, shortening attention 'span,' and causing learning disabilities." DRILLING DOWN, *supra* note 20, at vi (footnote omitted).

[85] "Radium is a known human carcinogen, causing bone, liver, and breast cancer." *Id.* (footnote omitted); *see also* AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, U.S. DEP'T OF HEALTH & HUMAN SERVS., TOXFAQS FOR RADIUM (1999).

[86] Chris Gray, *Pits Cause Stink in Lafourche*, TIMES-PICAYUNE, July 14, 1997, at A1.

[87] Miguel San Sebastian, Ben Armstrong, & Carolyn Stephens, *Outcomes of Pregnancy among Women Living in the Proximity of Oil Fields in the Amazon Basin of Ecuador*, 8 INTL. J. OF OCCUPATIONAL AND ECON. HEALTH 312 (2002).

kidney in men and for cancers of the cervix and lymph nodes in women.[88] As reports and first-hand accounts indicate, the risks posed by the contaminants found in E&P waste are not merely speculative. And the risks will not decrease anytime soon. As many pits containing E&P wastes are buried and forgotten, the buried E&P wastes have the potential to threaten future generations who will be unaware of the hazards just below the surface.

Human health can also be harmed by exposure to radiation in NORM-contaminated E&P wastes. Exposure can occur through inhalation of radium-bearing particles, through direct contact with NORM-contaminated soils and water, or through ingestion of radium-barium particles found in plants or animals exposed to NORM-contaminated soils or water.[89] Exposure to radium can result "in an increased risk of bone, liver, and breast cancer . . . . [it] has been shown to cause effects on the blood (anemia) and eyes (cataracts). It also has been shown to affect the teeth, causing an increase in broken teeth and cavities."[90] And the risks associated with NORM-contaminated soils and waters can persist for decades. In particular, land contaminated by radium 226, such as that found in produced water from the Marcellus Shale,[91] can pose a threat to "many generations of individuals living or working on NORM-contaminated land for a period covering nearing 20,000 years."[92]

ii. Substances in E&P Wastes Endanger Wildlife and Livestock.

In addition to harming human health, exposure to contaminants in E&P waste can sicken and kill wildlife. A recent report prepared by the U.S. Fish and Wildlife Service (USFWS) indicates that pits present significant risks to wildlife. Pits can "entrap and kill migratory birds and other wildlife . . . . Birds are attracted to reserve pits by mistaking them for bodies of water. . . . The sticky nature of oil entraps birds in the pits and they die from exposure and exhaustion."[93] In 2009, ExxonMobil pled guilty to violating the Migratory Bird Treaty Act,[94] after numerous birds (including mallard ducks, grebes, white-faced ibis, gadwell ducks, owls, Wilson pharalopes, Northern Shoveler ducks, avocets, curlew, a green-winged teal, a Cassin's sparrow, a purple

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[88] Anna-Karin Hurtig & Miguel San Sebastian, *Geographical Differences in Cancer Incidence in the Amazon Basin of Ecuador in Relation to Residence near Oil Fields*, 31 INT'L. J. OF EPIDEMIOLOGY 1021, 1025 (2002).
[89] Henry Spitz, Kennith Lovins & Christopher Becker, *Evaluation of Residual Soil Contamination From Commercial Oil Well Drilling Activities and Its Impact on the Naturally Occurring Background Radiation Environment*, 6 SOIL & SEDIMENT CONTAMINATION: AN INT'L J. 37, 43 (1997).
[90] AGENCY FOR TOXIC SUBSTANCES AND DISEASE REGISTRY, *supra* note 85.
[91] *See supra* note 37.
[92] Henry Spitz, Kennith Lovins & Christopher Becker, *Evaluation of Residual Soil Contamination From Commercial Oil Well Drilling Activities and Its Impact on the Naturally Occurring Background Radiation Environment*, 6 SOIL & SEDIMENT CONTAMINATION: AN INT'L J. 37, 41 (1997).
[93] U.S. FISH & WILDLIFE SERV., REGION 6, ENVTL. CONTAMINANTS PROGRAM, RESERVE PIT MANAGEMENT: RISKS TO MIGRATORY BIRDS i (2009).
[94] 16 U.S.C. §§ 703-708.

martin, and a hawk) were found sick and dead after being exposed to pit contents, including hydrocarbons, in multiple states.[95]

E&P wastes have the potential to destroy lands upon which wildlife depend, disrupt food chains, and prevent wildlife from reproducing.[96] The New Mexico Department of Game & Fish has expressed concern about the hazards of hydrocarbon toxicity to wildlife including "acute and chronic ingestion or absorption toxicity, loss of thermal stability from oiling of fur or feathers, and reproductive failure due to absorption of chemicals from the maternal bird body through the shell of eggs."[97] Other researchers are concerned about the bioaccumulation of E&P wastes in wildlife, a process that would cause their harmful effects to magnify as they progress up the food chain.[98] Wildlife habitat may also be harmed by E&P waste. The New Mexico Department of Game and Fish has stated that it "is concerned that chloride contamination of the soil vadose zone may permanently impact the ability of a closed pit location to support vegetation necessary for productive wildlife habitat."[99] Just as E&P wastes can harm humans in ways that are not immediately apparent but can cause harm to future generations, so too can they harm successive generations of wildlife.

Domesticated animals are also harmed by E&P wastes. The Pennsylvania Department of Agriculture quarantined cattle after they came into contact with hydraulic fracturing wastewater being stored in a pit that leaked into an adjacent field. The owners of the property where the pit was located noticed seepage from the pit for as long as two months prior to the leak. The Department stated that wastewater "contains dangerous chemicals and metals." Tests of the wastewater found that it contained strontium as well as other substances.[100] E&P waste is sometimes disposed of on land used for cattle grazing.[101] Residents of the Barnett Shale have reported seeing cattle drinking from sludge pits.[102] Cattle have been lost due to exposure to E&P waste in New Mexico[103] and 54 out of 56 hair samples from sick cattle analyzed by the Texas Veterinary Medical Diagnostic Laboratory contained petroleum.[104]

[95] Joint Factual Statement, U.S. v. Exxon Mobil Corp., ¶¶ 10–27 (D.Col. 2009).
[96] BRYAN M. CLARK, DIRTY DRILLING: THE THREAT OF OIL AND GAS DRILLING IN LAKE ERIE 25 (2002).
[97] Letter from Lisa Kirkpatrick, Chief, New Mexico Dep't of Game & Fish, Conservation Services Division, to Florene Davidson, Commission Secretary, EMNRD Oil Conservation Division (Jan. 20, 2006); *see also* Letter from Lisa Kirkpatrick, Chief, New Mexico Dep't of Game & Fish, Conservation Services Division, to Florene Davidson, Commission Secretary, EMNRD Oil Conservation Division (Mar. 7, 2006).
[98] BRYAN M. CLARK, *supra* note 96, at 25.
[99] Letter from Lisa Kirkpatrick, Chief, New Mexico Dep't of Game & Fish, Conservation Services Division, to EMNRD Oil Conservation Division (Feb. 2, 2007).
[100] Press Release, Pa. Dep't of Envtl. Prot., *Cattle from Tioga County Farm Quarantined after Coming in Contact with Natural Gas Drilling Wastewater* (July 1, 2010).
[101] *See e.g.*, Amended Complaint, Sweet Lake Land and Oil Co. v. Exxon Mobil Corp., No. 209CV01100, at ¶ 32 (W.D. La. filed Sept. 14, 2009), 2009 WL 4701364.
[102] Bluedaze: Drilling Reform for Texas blog (July 25, 2008).
[103] DRILLING DOWN, *supra* note 20, at 26.
[104] Test results from Veterinary Medical Diagnostic Laboratory on July 26, 2005, August 18, 2005, and September 6, 2005; DRILLING DOWN, *supra* note 20, at 26.

In response to occurrences like these, cattle ranchers and others whose animals are at risk have sought to prevent E&P waste disposal facilities from opening near their properties.[105] Protecting cattle and other domesticated animals from exposure to E&P wastes is particularly important as the hazardous contaminants of E&P wastes have the potential to bioaccumulate in these animals and potentially make their way into the human food chain.[106]

2. Current State Regulations and Enforcement Are Inadequate and Allow E&P Waste to Be Released into the Environment.

Waste produced in E&P operations is disposed of in a variety of ways, with underground injection and burial of waste historically being the most widely used methods.[107] Wastewater treatment facilities are another growing disposal method. Even before EPA made its 1988 Regulatory Determination, data indicated that commonly used disposal practices failed to prevent E&P wastes from contaminating soil and groundwater.[108] A 1987 report documented "the migration of leachate 400 feet from reserve pits buried in . . . North Dakota and reported groundwater contamination 50 feet below the buried reserve pits."[109] Incidences of soil and groundwater contamination have continued to occur since then.

E&P wastes may leak, spill, or evaporate into the air, allowing the chemicals used in oil and gas operations to be released into the environment. These releases occur in large part because many states' regulations do not adequately account for all of these potential modes of contamination, despite the fact that releases are occurring with alarming regularity, or are not vigorously enforced. The regulations of the Railroad Commission (RRC) of Texas have been described as providing only weak assurance that the "quality of waters (and land) will not be impacted by a gas operator's activity."[110] Assurances are similarly minimal in other states where regulations provide virtually useless oversight of E&P waste disposal because they fail to "clearly indicate acceptable disposal practices for all drilling wastes."[111]

An Ohio resident with 23 years of experience in drilling oil and gas wells testified before the state legislature that existing regulations are inadequate and cannot be appropriately enforced: "… the [Ohio Department of Natural Resources] has a serious lack of ability to enforce their own regulations due to the way the current law and this bill are written."[112] A review of Tennessee oil

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[105] Susan Hylton, *Drilling Waste Feud, Neighbors of Maverick Energy Services Think Water is Being Polluted*, TULSA WORLD, Mar. 21, 2010, at A11
[106] DRILLING DOWN, *supra* note 20, at 26.
[107] *See* E&P FORUM, EXPLORATION AND PRODUCTION (E&P) WASTE MANAGEMENT GUIDELINES 5 (Report No. 2.58/196, 1993).
[108] U.S. FISH & WILDLIFE SERV., *supra* note 93, at 4.
[109] *Id.*
[110] League of Women Voters of Tarrant County, Gas Drilling Waste-Water Disposal (2008).
[111] BRYAN M. CLARK, *supra* note 96, at 35.
[112] Testimony of James E. McCartney to the 128th General Assembly, Ohio Senate Environmental and Natural Resources Committee. Opponent Testimony on Senate Bill 165, Oct. 28, 2009.

and gas regulations found that the state does not have technical criteria for E&P waste management practices or any certification for E&P haulers.[113] Although all pits must be lined in Tennessee, pits are not considered or tracked through the permitting process and there are no security or wildlife protection measures.[114]

A 2009 letter from the EPA to the RRC of Texas states that the Commission should have "more rigorous evaluation" of conditions for waste disposal wells.[115] Texas also "allows companies to hire their own environmental consultants to check for contamination."[116] These regulatory failures existed when EPA issued its 1988 Regulatory Determination, and have been exacerbated in the wake of EPA's decision not to regulate E&P wastes under Subtitle C of RCRA.

a. Pits

Pit construction requirements vary greatly across the country. While a few states, such as New Mexico and Colorado, have recently adopted stricter rules governing the disposal of E&P wastes in pits, other states have minimal regulations and often do not even require the use of pit liners.[117]

The open design of pits, combined with the often minimal regulatory requirements governing their construction and use, present greater opportunities for their dangerous contents to be released into the environment. Reports indicate that the release of E&P wastes from pits is far too common.

In September 2008, New Mexico compiled its data on cases where pit substances contaminated New Mexico's groundwater.[118] The numbers were staggering: More than 700 incidents of groundwater contamination by oilfield wastes or products were documented.[119] Elsewhere, in 2001, E&P wastes from the Black Mountain disposal facility in Colorado contaminated nearby soil and groundwater when its clay lined pits began to leak.[120] Since then, many more releases of E&P wastes have occurred in Colorado. The Colorado Oil and Gas Conservation Commission (COGCC) documented several pits at the same pad site in Garfield

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[113] TENNESSEE DEP'T OF ENV'T & CONSERVATION, STATE REVIEW OF OIL AND NATURAL GAS ENVIRONMENTAL REGULATIONS, INC., TENNESSEE STATE REVIEW 13, 19, 22, 24 (2007).
[114] *Id.* at 30.
[115] FY2008 EPA Region 6 End-of-year Evaluation of the Railroad Commission of Texas Underground Injection Control Program, with transmittal letter from Bill Luthans, Acting Director, Water Quality Protection Division, Region 6 to Tommie Seitz, Director, Oil and Gas Division (June 19, 2009).
[116] Joe Carroll, *Exxon's Oozing Texas Oil Pits Haunt Residents as XTO Deal Nears*, Bloomberg Businessweek, April 16, 2010.
[117] *See infra* notes 146–160 and accompanying text; *see also* OKLA. ADMIN. CODE § 165:10-7-16(b)(1)(B)(iii), (2)(b).
[118] NEW MEXICO ENERGY, MINERALS AND NATURAL RES. DEP'T, OIL CONSERVATION DIV., CASES WHERE PIT SUBSTANCES CONTAMINATED NEW MEXICO'S GROUND WATER (2008).
[119] Oil & Gas Accountability Project, Groundwater Contamination.
[120] Kim Weber, Regarding Support of HB 1414—Evaporative Waste Facilities Regulations.

County whose liners had torn and allowed wastes to be released on multiple occasions between April and August 2008.[121] The reports indicated that the pits were located on rocky terrain and that some of the liners had been torn by rocks on the site.[122] In total, more than 6,000 barrels of pit contents escaped the pits because of the tears.[123] In La Plata County, a landowner reported the possible contamination of his well by an unlined reserve pit located a mere 350 feet uphill from his well.[124] The COGCC eventually concluded that "it appear[ed] that fluids from the unlined reserve pit infiltrated into the shallow groundwater, flowed downhill and impacted the Thomson water well."[125] The COGCC has documented numerous other incidents where pits have leaked,[126] overflowed, [127] or been unlined,[128] thereby allowing their contents to be absorbed by unprotected ground.

In May, 2008, a Colorado citizen drank water from his spring and fell ill. The COGCC found benzene in the groundwater that exceeded standards by 32 times and benzene in faucet water that exceeded standards by 13 times, as well as elevated levels of toluene and xylenes. Although the COGCC began investigating this complaint in June, 2008, it wasn't until October, 2008, that the operator stated that it became aware that the production pit was never permitted. The state appears to have been unaware that the pit was never permitted even though it was investigating the pit as a possible source of groundwater contamination. In July, 2010, the COGCC found that the operator failed to properly permit, construct, maintain, and repair the pit, leading to a release or releases of E&P waste that impacted groundwater. The agency found that the liner had been stretched over rocks and had improperly sealed seams.[129]

In addition to the reports from New Mexico and Colorado, there have been many complaints by citizens of contamination reportedly caused by E&P wastes in other states. NYSDEC has received numerous reports of E&P waste releases, many of which have contaminated soil and

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[121] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1630424, 1630426, 1630427, 1630428, 1630429, 1630430.
[122] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NO. 1630428.
[123] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1630424 (714 bbls), 1630426 (2000 bbls), 1630427 (500 bbls), 1630428 (1250 bbls), 1630429 (204 bbls), 1630430 (2017 bbls).
[124] Oil & Gas Accountability Project, Contamination Incidents Related to Oil and Gas Development, Maralex Drilling Fluids in Drinking Water; COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORT, DOC. NO. 1953000.
[125] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, NOAV REPORT, DOC. NO. 200085988; *see also* Oil & Gas Accountability Project, Contamination Incidents Related to Oil and Gas Development, Maralex Drilling Fluids in Drinking Water.
[126] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1631518, 1631599, 2605176, 2605847.
[127] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 200225543, 200225547, 200225546.
[128] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NO.1632846.
[129] Colorado Oil and Gas Conservation Commission, Cause No. 1V, Order No. 1V, Docket No. 1008-OV-06

groundwater.[130] In June 1987, in West Seneca, N.Y., product from an open pit containing oil and other solvents was found running from the pit towards a nearby creek.[131] In November 1996, in Reading, N.Y., a produced water pit overflowed and spilled approximately two hundred gallons of produced water into a creek feeding into Seneca Lake.[132] NYSDEC determined that no cleanup was possible.[133] When a property owner in Bolivar, N.Y., called in June 2002 to report leaking oil wells, NYSDEC inspectors also found unlined leaking containment ponds.[134]

E&P wastes in pits have been released into the environment in other states as well. Pennsylvania's Department of Environmental Protection (PADEP) has documented several incidents of dangerous E&P waste releases into the environment. Notably, at two of Atlas Resources LLC's well sites in Pennsylvania, "compromised" pit liners allowed fracturing flowback fluids to escape.[135] In Ohio, a fracturing flowback pit was cut with a track hoe in 2010, causing more than 1.5 million gallons of fluid were spilled into the environment.[136] In 2008, the back wall of a pit in Ohio gave way, causing pit contents to spill and flow towards a creek.[137]

In addition to releases caused by torn liners and overflows, pits allow the hazardous contaminants in E&P wastes to be released into the environment through evaporation into the air. E&P wastes such as produced water stored in open pits can "release methane, toxic volatile organic chemicals and sulfur based compounds into the air."[138] Rocky Mountain Clean Air Action collected data showing that wastewater evaporation pits in Garfield County, Colorado are "major sources of air pollution and pose greater threats to human health than previously reported."[139] The data indicated that high levels of hydrocarbons and other hazardous air pollutants were being released into the air. [140] Also in Garfield County, beginning in October 2005, a resident repeatedly notified the COGCC that severe odors were emanating from an E&P waste pit located close to her home.[141] In early December 2005, the resident reported smelling "a different sort of stench . . . the 'Benzene smell'" to the COGCC and requested that the agency

[130] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST (2009).
[131] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 37 (2009) (Spill Number: 8702469).
[132] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 53 (2009) (Spill Number: 9610217).
[133] *Id.*
[134] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 124-25 (2009) (Spill Number: 0275147).
[135] Consent Assessment of Civil Penalty, In re Atlas Resources LLC, Dancho-Brown 4, ¶¶ AV–AZ, Groves 8, ¶¶ BA–BE.
[136] Ohio Department of Natural Resources, Notice of Violation No. 1278508985, June 21, 2010.
[137] Ohio Department of Natural Resources, Notice of Violation No. 2016754140, May 16, 2008.
[138] Subra, *supra* note 43.
[139] Phillip Yates, *Clean Air Group Contends Evaporation Ponds in Garfield County More Dangerous than Previously Believed*, POST INDEPENDENT, Jan. 9, 2008.
[140] *Id.*
[141] Oil & Gas Accountability Project, Contamination Incidents Related to Oil and Gas Development.

install full-time air monitoring equipment.[142] At the end of the month, the resident learned that sampling of the air fairly close to the pit "showed that benzene and xylenes exceeded the [EPA's] 'non-cancer risk levels' for these compounds – at 67 µg/m3, benzene was present at more than double the risk level. Other detectable compounds included acetone, toluene and ethylbenzene."[143]

While some incidents are effectively reported and prosecuted by state authorities, many more incidents occur that are not addressed adequately by state officials. In these cases, the citizens affected by such releases into the environment have instead turned to the judicial system in order to hold the oil and gas companies accountable. John Preston Stephenson, Jr. sued Chevron U.S.A alleging that waste from Chevron oil pits contaminated his property with "hazardous toxic and carcinogenic chemicals."[144] Similarly, the Sweet Lake Land and Oil Company sued multiple defendants, including Exxon, Noble Energy, Inc., and Texas Eastern Skyline Oil Company, for contamination of "the soil and groundwater with produced water, oil, drilling muds, technologically enhanced naturally occurring radioactive materials (sometimes referred to as 'TENORM'), hydrocarbons, metals, and other toxic and/or hazardous substances, wastes and pollutants," claiming that the defendants knew the pits contents would contaminate the plaintiff's surface and subsurface soil and water.[145] Sweet Lake Land and Oil Company further alleged that "[t]he presence of the pits, substances and scrap on and under the Property constitutes a nuisance."[146] These claims are only a handful of many more by citizens who have been harmed by E&P wastes released from pits.[147]

These reports of contamination are at least partially attributable to inadequate state efforts to regulate E&P waste disposal in pits. Despite the fact that pit contents have been found to contain hazardous contaminants,[148] many states fail to require operators to use the most basic of precautions. Tennessee, for example, does not even take pits into account in its permitting process, thereby "making their management and disposal difficult to track" and increasing the

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[142] COLORADO OIL AND GAS CONSERVATION COMMISSION, INSPECTION/INCIDENT INQUIRY, COMPLAINT REPORT, DOC. NO. 200081602.
[143] Oil &Gas Accountability Project, *supra* note 141.
[144] Amended Complaint at ¶ 9, Stephenson v. Chevron U.S.A, Inc., No. 209CV01454, (W.D. La. filed Sept. 11, 2009), 2009 WL 4701406.
[145] Sweet Lake Land and Oil Co. v. Exxon Mobil Corp., *supra* note 101, at ¶ 10.
[146] *Id.* at ¶ 27.
[147] *See also* Petition for Damages, Brownell Land Corp., LLC v. Honey Well Int'l., No. 08CV04988, ¶¶ 11-12 (E.D. La. filed Nov. 21, 2008), 2008 WL 5366168; Rice Agricult. Corp., Inc., v. HEC Petroleum Inc., 2006 WL 2032688 (E.D. La); Petition for Damages, Tensas Poppadoc, Inc. v. Chevron U.S.A., Inc., No. 040769, ¶ 8 (7th Judicial Court La. filed Sept. 21, 2005), 2005 WL 6289654; Petition for Damages to School Lands, Louisiana v. Shell Oil Co., No. CV04-2224 L-O, (W.D. La. filed Oct. 29, 2004), 2004 WL 2891505 (where the State of Louisiana and the Vermilion Parish School Board made similar allegations against Shell Oil, claiming they had contaminated school property. In July 2006, the case was remanded to state court).
[148] *See* notes 62–67 *supra*.

likelihood that the locations of the wastes will be forgotten in the future.[149] In addition, Tennessee has no freeboard or liner integrity requirements,[150] does not require testing or tracking of pit wastes,[151] and fails to require oil to be removed from pits.[152] Kentucky similarly turns a blind eye to the risks E&P wastes present to the public through its failure to require testing of E&P waste characteristics and its treatment of all E&P wastes except production brines and drilling muds as solid wastes, subject to less stringent disposal requirements "irrespective of the risk posed to human health or the environment from the waste."[153]

States also fail to take other simple steps that would dramatically decrease the likelihood of E&P wastes being released into the environment, for example, requiring pits to be lined with impermeable barriers. In Oklahoma, neither emergency pits nor pits holding water-based drilling fluids are required to have any lining.[154] This failure to require the use of a liner in pits holding water-based drilling fluids increases the risk that the "barite, clays, lignosulfonate, lignite, caustic soda and other specialty additives" found in water-based muds will contaminate the environment.[155] Kentucky's liner requirements are also inadequate. Kentucky does not require the use of liners in drilling pits that are used for less than thirty day storage and has "minimal liner requirements for holding pits" for storage over thirty days.[156]

Wildlife protection devices are another important and too often underused safety measure. Tennessee,[157] Louisiana,[158] and Kentucky all fail to require any "fencing, flagging or netting of pits," thereby increasing the risks the pits present to wildlife and domestic animals.[159] And according to a recent report prepared by Region 6 of the U.S. Fish & Wildlife Service, these three states are not alone.[160] As reported by Region 6, only thirteen states require pits or open tanks to be screened or netted to prevent wildlife from coming into contact with E&P wastes.[161] The failure to require pit operators to use even the most basic protection devices such as fencing or netting greatly increases the likelihood that wildlife will come into contact with E&P waste and suffer significant harm.

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[149] TENNESSEE DEP'T OF ENV'T & CONSERVATION, *supra* note 113, at 30.
[150] *Id.*
[151] *Id.* at 32.
[152] *Id.* at 31.
[153] STATE REVIEW OF OIL AND NATURAL GAS ENVIRONMENTAL REGULATIONS, INC., KENTUCKY STATE REVIEW 50–51 (2006).
[154] OKLA. ADMIN. CODE § 165:10-7-16(b)(1)(B)(iii), (2)(b).
[155] CORCORAN ET AL., *supra* note 25, at 20; *see also* U.S. FISH & WILDLIFE SERV., *supra* note 93, at 4–5 ("Water-based drilling muds can contain glycols, chromium, zinc, polypropylene glycol, and acrylamide copolymers.").
[156] KENTUCKY STATE REVIEW, *supra* note 153, at 54.
[157] TENNESSEE DEP'T OF ENV'T & CONSERVATION, *supra* note 113, at 30.
[158] STATE REVIEW OF OIL AND NATURAL GAS ENVIRONMENTAL REGULATIONS, INC., LOUISIANA STATE REVIEW 29 (2004).
[159] *Id.*
[160] U.S. FISH & WILDLIFE SERVICE, *supra* note 93, at 13 fig. 15.
[161] *Id.*

States also fail to regulate where pits may be located, allowing them to be placed near residences, schools, and other areas frequently used by the public. In some cases, homes are located so close to pits that residents have been forced indoors because of the foul odors and health symptoms emanating from the pits. One Pennsylvania family reported severe headaches caused by fumes from a pit less than 200 feet from their home.[162] As of 2005, when STRONGER, Inc. conducted a review of Indiana's E&P waste disposal practices and regulations, Indiana regulations had no requirements regarding "specifications for the location, orientation and construction of drilling pits. There [were] no required setbacks of minimum distances from buildings, homes or other structures for drilling pits." Since then, although Indiana has adopted a new rule requiring pits to be located at least one hundred feet from streams, rivers, lakes and drainage ways, it still does not specifically require pits to be setback from other structures.[163] By allowing pits to be sited close to where people live and children attend school, state regulators are bringing health risks literally closer to the citizens across the country.

b. Land application

EPA has stated that hazards also exist with land application of E&P wastes, finding that hydrocarbons, salts, and metals can all cause contamination when E&P wastes are land applied.[164] The Oil Industry International Exploration and Production Forum (E&P Forum), an international industry association, has also issued warnings, stating that land application may result in contaminants accumulating "in the soil [at] a level that renders the land unfit for further use."[165] New York State allows waste to be disposed of in municipal landfills.[166] Land where only oil and gas waste is applied is often called a "landfarm." Studies of landfarm conditions confirm that these hazards are real. When the Arkansas Department of Environmental Quality conducted a study of landfarms in Arkansas, it found that "all 11 sites that land applied fluids at some point had improperly discharged the fluids so as to cause runoff into the waters of the state."[167]

Land application sites outside of Arkansas are sources of similar concerns. Near Holdenville, Oklahoma, residents protested the opening of a landfarm because they were worried about

[162] Christie Campbell, *Foul Odor from Impoundment Upsets Hopewell Woman*, OBSERVER-REPORTER, Apr. 14, 2010. June Chappel, who lives near a pit, stated that the odor "reminded her of a hair perm. It smelled like ammonia . . . [and] 'took your breath away.'" *Id.* Other times the fumes have smelled like gasoline, diesel fuel, and sewage. *Id.*
[163] 312 IND. ADMIN. CODE 16-5-13 (2010).
[164] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006, at 49 (2000).
[165] E&P FORUM, *supra* note 107, at 17.
[166] Letter from Gary M. Maslanka, New York State Division of Solid & Hazardous Materials, to Joseph Boyles, Casella (April 27, 2010).
[167] Press Release, Arkansas Dep't of Envtl. Quality, ADEQ Releases Landfarm Study Report (Apr. 20, 2009).

potential "water contamination and land spoilage."[168] After the residents lost two appeals in which they tried to prevent its opening, the landfarm finally began operations and made the residents' fears a reality. Claudia Olivo, who owns a cattle ranch adjacent to the landfarm, filed a complaint with EPA after she noticed "strange glistening spots in the water" on her property.[169] In response, EPA issued a cease-and-desist order against the landfarm after finding that it had made unauthorized discharges of drilling mud into a creek that ran through Olivo's property, in violation of the Clean Water Act.[170] The Crouch Mesa landfarm in Aztec, New Mexico, is located directly across the street from a residential area and is the source of considerable visible dust observed blowing toward homes.[171]

Despite these risks, many states inadequately regulate land application. In Oklahoma, one-time land applications may occur as close as one hundred feet from any perennial stream, freshwater pond, lake or wetland.[172] Tennessee regulations fail to provide any explicit guidance regarding the use of land applications.[173] Meanwhile, Kentucky has no siting criteria for land application specific to E&P wastes.[174]

These lax regulations result in E&P wastes being land applied near, and in some cases, on residential property, increasing the likelihood that humans will be exposed to E&P waste's toxic compounds.[175] In Martha, Kentucky, produced water and tank bottoms were land applied on farmland near where a family of two adults and two children lived.[176] The family grew the majority of the vegetables and meat they consumed on the farm,[177] and the portion of the family's land used for storing E&P waste disposal was located a mere 100 feet from a small creek which "drains into a marsh, which then drains into a larger creek" from which the farm's cattle drank.[178] The family no longer drinks from its well, which has been contaminated with benzene.[179] Lead and arsenic were found in soil samples.[180] In addition, areas of the farm where E&P wastes had been disposed were found to be NORM-contaminated sites which "will remain radioactive for many thousands of years," "creating many opportunities for radium to enter the soil and be taken up by plants or cattle grazing on the land," and threatening "[f]uture inhabitants or workers on the NORM-contaminated land [who] may also be directly exposed to ionizing

[168] Susan Hylton, *supra* note 105, at A11.
[169] *Id.*
[170] *Id.*
[171] DRILLING DOWN, *supra* note 20, at 22.
[172] OKLA. ADMIN. CODE § 165:10-7-26(c)(6) (2009).
[173] TENNESSEE DEP'T OF ENV'T & CONSERVATION, *supra* note 113, at 32.
[174] KENTUCKY STATE REVIEW, *supra* note 153, at 50.
[175] *See* WOLF EAGLE ENVIRONMENTAL, *supra* note 70.
[176] Spitz et al., *supra* note 92, at, 45.
[177] *Id.* at 46.
[178] *Id.* at 45.
[179] *Id.*
[180] *Id.* at 55.

radiation or inhale radium-bearing particles."[181] As demonstrated by the contamination that occurred in Martha, Kentucky, inadequate state regulations too frequently fail to protect the public and the environment from the hazards associated with land application of E&P wastes.

A Texas resident lives fifty feet away from a 100-acre land farm, where the Texas Railroad Commission issued 22 minor permits for 22 different operations that are all located on one property. A second land farm is located just down the road.[182]

c. Injection Wells

Underground injection, the most widely used disposal method,[183] also poses concerns. If the formation into which E&P wastes are injected does not meet certain levels of permeability, porosity, and low reservoir pressure, the formations can form a poor seal around the E&P wastes and threaten nearby aquifers.[184] Under the Underground Injection Control (UIC) Program, E&P wastes may be injected in Class II wells, while wastes designated as hazardous under RCRA can only be disposed of in the more strictly regulated Class I wells.[185]

The lower standards applicable to Class II wells have proven inadequate to prevent E&P wastes from contaminating groundwater. In 1988, GAO released a report, *Safeguards Are Not Preventing Contamination from Injected Oil and Gas Wells,* which examined the effectiveness of EPA's UIC program.[186] Although GAO speculated that it was likely that more incidents had occurred, it reported that the EPA was aware of at least 23 cases across the country where Class II injection wells had contaminated drinking water supplies.[187] Since then more incidences of concern have occurred.

In September 2007, a state inspector in Texas inspected an underground injection disposal well site outside of Fort Worth and found no problems. Yet a resident complained of "spilled oil, overflowing dikes and green-colored fluid in standing puddles." Inspectors returned and found that "oil-stained soil" had seeped several inches into the ground, that the "containment dike will not hold estimated capacity," and that standing water had oil in it. State records showed that the well site was not being used, when in fact it was actively being injected with oil and gas waste.[188]

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[181] *Id.* at 57.
[182] *See* Griffey, *supra* note 71
[183] M.G. PUDER & J.A. VEIL, ARGONNE NATIONAL LABORATORY, OFFSITE COMMERCIAL DISPOSAL OF OIL AND GAS EXPLORATION AND PRODUCTION WASTE: AVAILABILITY, OPTIONS, AND COSTS, S-2 (2006) ("By far, the most common commercial disposal method for produced water is injection.").
[184] *See* E&P FORUM, *supra* note 107, at 15.
[185] DRILLING DOWN, *supra* note 20, at 17; *see also* 42 U.S.C § 300h-4; 42 U.S.C § 300h(b); 42 U.S.C. § 300(h)-1(c).
[186] U.S. GENERAL ACCOUNTING OFFICE, *supra* note 32, at 2.
[187] *Id.* at 3.
[188] Abrahm Lustgarten, *State Oil and Gas Regulators Are Spread Too Thin to Do Their Jobs,* ProPublica, December 30, 2009.

Residents in DeBerry, Panola County, Texas, first began complaining that their groundwater was contaminated in 1996.[189] An underground injection disposal facility began operations one-eighth of a mile away from the community in 1987, injecting produced water into the ground at depths between 1,080 and 1,110 feet.[190] In 1996, while the well was still in operation, DeBerry residents told an EPA Region 6 employee that their water was discolored, was staining their kitchen and bath fixtures, and that they were experiencing gastrointestinal problems.[191] The residents of DeBerry ultimately stopped using their drinking water and instead began to obtain water from other sources.[192] No government agency tested DeBerry's drinking water for several years after residents first complained. Not until 2002 did the site operator of the injection wells in DeBerry, Basic Energy, sample the drinking water.[193] When it did, the residents' suspicions were confirmed. The results showed the presence of contaminants above the EPA's maximum contaminant levels.[194] In 2003, the Texas RRC found benzene, barium, arsenic, cadmium, lead and mercury in wells at levels exceeding the state's drinking water standards.[195] Because the Texas RRC never completed a full assessment of the contamination, the source of the contamination is not definitively known; however, residents strongly believe the injection wells were the cause of the contamination, and EPA has been unable to rule this possibility out conclusively.[196]

Also in Texas, an underground injection disposal facility in Daisetta is linked to contamination of a fresh water aquifer. The EPA found a lack of compliance reviews, inappropriate monitoring, and incomplete record-keeping, as well as a lack of evidence that all problems were ever remedied. This problematic facility led to a surface collapse and a large sinkhole.[197]

The likelihood that similar incidents will continue to occur exists as long as underground injection associated with oil and gas exploration, production, and development only has to meet the requirements for Class II wells and states fail to require better monitoring.

In addition, a vast amount of E&P waste is being injected underground without any UIC regulation whatsoever. Used hydraulic fracturing fluid—perhaps millions of gallons per each

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[189] EPA OFFICE OF THE INSPECTOR GENERAL, COMPLETE ASSESSMENT NEEDED TO ENSURE RURAL TEXAS COMMUNITY HAS SAFE DRINKING WATER, NO. 2007-P-00034 2 (2007).
[190] *Id.* at 3.
[191] *Id.* at 2.
[192] *Id.*
[193] *Id.*
[194] *Id.*
[195] *Hearing Before the Subcomm. on Superfund and Environmental Health of the S. Comm. on Environment and Public Works* 12–13 (2007) (statement of Robert D. Bullard, Dir. Environmental Justice Resource Center).
[196] EPA, OFFICE OF THE INSPECTOR GENERAL, *supra* note 189, at 3.
[197] EPA, *supra* note 115.

well—remain underground permanently. It has been estimated that up to 90% of hydraulic fracturing fluids used in the Marcellus shale formation remain underground.[198] Yet this waste disposal and storage activity is not subject to any federal underground injection regulations.

d. Wastewater Treatment Facilities

In regions where underground injection is not readily available, hydraulic fracturing wastewater and produced water may be sent to wastewater treatment plants prior to release to surface water. The plants may be publicly owned treatment works (POTWs) that typically process municipal sewage or centralized wastewater treatment (CWT) facilities that process industrial wastes. None of the POTWs and few of the CWT plants currently in operation have the capacity to reduce to safe levels all of the chemical contaminants commonly found in E&P waste. As a result, toxins are released to surface water, with adverse impacts on drinking water quality. The very high concentrations of total dissolved solids (TDS)—principally salts—that are common in hydraulic fracturing wastewater and produced water present a particular problem for wastewater treatment facilities.

Without adequate pretreatment, pollutants in oil and gas waste will pass through a POTW into the receiving stream, and they may interfere with ordinary sewage treatment systems.[199] Even with pretreatment, POTWs are not effective in removing salts from those wastes.[200] The use of POTWs for treatment of E&P waste in western Pennsylvania produced TDS levels in the Monongahela River in excess of drinking water standards, forcing the Commonwealth to limit the waste to one percent of influent at nine plants along the river.[201] Unauthorized discharges of pollutants, including fecal matter, from a POTW into the Susquehanna River were attributed to the plant's acceptance of oil and gas wastes.[202] Even CWT plants rarely have the evaporation and crystallization technologies needed to reduce extremely high levels of TDS in hydraulic fracturing wastewater and produced water (up to 300,000 mg/l) to levels consistent with water quality standards (500 mg/l). There is not a single CWT facility with that capacity in all of New York or Pennsylvania.[203]

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198 PROCHEMTECH INTERNATIONAL, INC., MARCELLUS GAS WELL HYDROFRACTURE WASTEWATER DISPOSAL BY RECYCLE TREATMENT PROCESS.
199 N.Y. State Water Res. Inst., *Waste Management of Cuttings, Drilling Fluids, Hydrofrack Water and Produced Water*; Oh. Envtl. Prot. Agency, *Marcellus Shale Gas Well Production Wastewater*.
200 *Id.*
201 Joaquin Sapien, *With Natural Gas Drilling Boom, Pennsylvania Faces an Onslaught of Wastewater*, ProPublica, Oct. 4, 2009; *Municipal Authorities' Perspective: Marcellus Shale Natural Gas Wastewater Treatment, Hearing Before the S. Comm. on Envtl. Res. & Energy* (Pa. 2010) (statement of Peter Slack, Pennsylvania Municipal Authorities Ass'n).
202 Press Release, Pa. Dep't Envtl. Prot., DEP Says Jersey Shore Borough Exceeds Wastewater Permit Limits (June 23, 2009).
203 N.Y. State Water Res. Inst., *supra* note 199; Joaquin Sapien, *supra* note 201.

e. Other spills, leaks, and intentional dumping

In addition to those releases that commonly occur when these common E&P waste disposal methods are being used properly, many other spills and releases occur before E&P wastes reach these storage or disposal sites. These other releases can be the result of equipment failure, accidents, negligence, or intentional dumping. Consistent federal regulations for waste management, storage and disposal would help prevent them in the future.

For example, in Pennsylvania, Atlas Resources LLC "discharged residual and industrial waste, including diesel and production fluids, onto the ground at seven of the 13 well sites."[204] At three of the wells Atlas allowed produced water to be released into the environment.[205] Pennsylvania records also show that pipes used to transport waste, sometimes for miles, have leaked. In October, 2009, a pipe carrying diluted wastewater spilled about 10,500 gallons into a high-quality stream, killing about 170 small fish and salamanders. In December, 2009, a pipe failed in five places, spilling an estimated 67,000 total gallons of fluid, tests of which found elevated levels of salts, barium and strontium.[206]

NYSDEC has documented numerous other examples of releases. In October 1997, a produced water tank in Willing, New York, containing produced water from natural gas extraction overflowed and contaminated the surrounding soil and a nearby creek from which cows drank with fifteen thousand gallons of produced water.[207] The produced water killed vegetation in its path.[208] More recently, in September 2005, eight hundred gallons of production brine from another tank in Pine City, New York, overflowed when it was not emptied on schedule, causing an impact on nearby streams.[209] In July 1996, crude oil tank bottoms were dumped into a pit and set on fire.[210] In March 2003, a property owner in Ithaca, New York, called to report that a driller was dumping mud on his property.[211] In May 2007, NYSDEC received an anonymous tip indicating that produced water from a natural gas well was being

[204] Press Release, Pa. Dep't Envtl. Prot., DEP Fines Atlas $85,000 for Violations at 13 Well Sites, Jan. 7, 2010.
[205] Consent Assessment of Civil Penalty, *In re Atlas Resources LLC*, Pevarnik 8, ¶¶ Z–AD, Willis 18, ¶¶ AE–AI, Thompson 33 ¶¶ AP–AU.
[206] Laura Legere, *Massive Use of Water in Gas Drilling Presents Myriad Chances for Pollution*, SCRANTON TIMES-TRIBUNE, June 22, 2010.
[207] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 3 (2009) (Spill Number: 9707892).
[208] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 4 (2009) (Spill Number: 9707892).
[209] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 8 (2009) (Spill Number: 0507041).
[210] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 23 (2009) (Spill Number: 9604701).
[211] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 68 (2009) (Spill Number: 0212276).

dumped on the ground near Cayuga Creek in Sheldon, New York.[212] In May 2009, eight hundred gallons of produced water contaminated soils in Westfield, New York, after equipment failed and allowed the fluids to be released into the environment a mere 1200 yards away from nearby homes.[213]

The COGCC has also documented incidents where tanks have been improperly sealed[214] or allowed to overflow,[215] where corroded equipment allowed produced water to contaminate the ground,[216] and where equipment failure has allowed produced water to escape from underground injection wells.[217] Between June 2002 and June 2006, 555 produced water spills were reported to the COGCC.[218]

In Texas, between 2001 and 2006, thirty percent of spill complaints were inspected "either late or not at all."[219] Most recently in the Texas town of Flower Mound, the Texas RRC sent out a notification stating that approximately 3,000 gallons of "flowback water containing fracturing fluid and associated additives" spilled out of gas well pad site.[220] To date, the RRC has not publically released either the cause of the spill or the exact contents of the flowback water.[221]

The mayor of West Union, West Virginia, wrote a letter to the WVDEP in October 2009 to express his concern over WVDEP's failure to notify the town until two months after a spill occurred.[222] The mayor was even more concerned about WVDEP's failure to have any emergency notification system in place, stating that the continued failure to establish such a system "will only result in less time for the water system to react [to future spills] and [result in] a greater chance of catastrophe."[223] Elsewhere in West Virginia, Luanne McConnell Fatora reported a release of between fifty and seventy barrels of some type of oil and gas waste in a

[212] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 159 (2009) (Spill Number: 0750225).
[213] TOXICS TARGETING, INC., HAZARDOUS MATERIALS SPILLS INFORMATION REQUEST 143 (2009) (Spill Number: 0902327).
[214] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORT, DOC. NO. 1630697.
[215] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1631155, 1631831, 1631794, 1632853.
[216] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 1630885, 1631496, 1631519, 1632057, 2605191, 1632995.
[217] COLO. OIL & GAS CONSERVATION COMM'N, INSPECTION/INCIDENT INQUIRY, SPILL REPORTS, DOC. NOS. 200226284, 200225725, 2605709.
[218] OIL & GAS ACCOUNTABILITY PROJECT, COLORADO OIL AND GAS INDUSTRY SPILLS: A REVIEW OF COGCC DATA (JUNE 2002-JUNE 2006) 1-2 (2006).
[219] Lustgarten, *supra* note 188.
[220] *Frac Fluid Spill Reported in Flower Mound*, CROSS TIMBERS GAZETTE, Mar. 17, 2010.
[221] *Id.*
[222] Letter from Robert F. Fetty, Mayor, Town of West Union, to Barbara Taylor, Director, WVBPH/Office of Environmental Health Services, Oct. 28, 2009.
[223] *Id.*

stream in Doddridge County.[224] Fatora's son discovered the spill when he tried to go fishing in the stream in late August 2009 and found the water to be "acrid" and covered with a "red/orange gel" that had an oily smell which got on his hands and did not "go away for some time despite repeated washing."[225] Although the Chief of the West Virginia Oil and Gas Office stated that the fluids were consistent with oil and gas waste, more than a month after the spill the WVDEP remained uncertain about what caused the release.[226]

These releases, and the undoubtedly numerous other unreported incidents, demonstrate that current regulations and regulatory enforcement is inadequate to prevent E&P wastes from being released into the environment.

3. Oil & Gas Production Has Increased Dramatically Since 1988.

When EPA released its 1988 Regulatory Determination, the domestic oil and natural gas industry was struggling. Since then, oil and natural gas production in the United States has increased dramatically. Tens of thousands of new oil wells have been drilled. According to the U.S. Energy Information Administration (US EIA), between 1989 and 2008 the number of producing gas wells nationwide almost doubled, increasing from roughly 262,000 to 479,000 wells.[227]

Bureau of Land Management (BLM) statistics also demonstrate the growth in oil and gas operations under its jurisdiction. In most years during the 1990s, there were less than four thousand applications for permits to drill (APDs) filed with the BLM.[228] BLM has stated that "[s]ince 1996, the number of new APDs has risen dramatically."[229] BLM received more than ten thousand APDs in 2006.[230] Although BLM projects that the number of APDs will decline by 2010,[231] BLM still expects to receive a staggering number, approximately 7,000, of APDs in 2010. Furthermore, BLM attributes this projected decrease to the fact that a larger percentage of proposed drilling is expected to occur on existing leases and not to a decrease in drilling.[232]

State agency statistics also demonstrate an increase in the amount of domestic drilling: one example is Texas, where the number of permits issued by the RRC for drilling in the Barnett

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[224] Ken Ward Jr., *What Caused Big Fracking Fluid Spill in Doddridge County?*, SUSTAINED OUTRAGE: A GAZETTE WATCHDOG BLOG (Oct. 2, 2009); *see also* Letter from Louanne McConnell Fatora to Gov. Manchin, West Highlands Conservancy (Aug. 30, 2009).
[225] Letter from Louanne McConnell Fatora to Gov. Manchin, (Aug. 30, 2009).
[226] Ward Jr., *supra* note 224.
[227] U.S. ENERGY INFO. ADMIN., NUMBER OF PRODUCING GAS WELLS (2009).
[228] BUREAU OF LAND MGT., BLM FY 2010 BUDGET JUSTIFICATIONS III-120 (2010).
[229] *Id.* at III-119.
[230] *Id.* at III-120.
[231] *Id.*
[232] *Id.* at III-122.

Shale increased from 273 in 2000 to 3,653 in 2007,[233] and 4,145 in 2008.[234] Industry-wide, API statistics confirm that these increases are not isolated incidents. The API reported that 2006 was a record year for gas drilling, in which more than 29,000 new wells were drilled.[235] The API expected that this trend would continue and it did: a new 21-year record was reached when 11,771 wells were drilled in the first-quarter of 2007.[236]

Along with this increase in drilling, there has been an associated increase in the amount of E&P waste produced. In Utah's Uintah County the amount of produced water generated from oil and gas operations increased from approximately 800,000 barrels per month in January 1999 to over 1,600,000 barrels per month in January 2007.[237] Even though some techniques have been implemented to reduce the amount of produced water generated from oil and gas extraction activities, EPA's Region 8 noted an overall two percent increase in the amount of produced water generated from 2002 to 2008.[238] The increases in both drilling and E&P waste that have occurred since 1988 indicate that the risks associated with E&P wastes have become even more substantial and that EPA must revisit its Regulatory Determination in light of these developments.

4. Regulation Under Subtitle C of RCRA Would Not Harm the Oil & Gas Industry.

In its 1988 Regulatory Determination, EPA placed significant weight on the potential harm that increased regulation of E&P waste could cause the oil and natural gas industry in making its determination not to regulate E&P wastes under Subtitle C of RCRA. EPA claimed that regulating E&P wastes under Subtitle C would be "extremely costly" for industry.[239] EPA also asserted that "[a]ny program to improve management of oil and gas wastes in the near term will be based largely on technologies and practices in current use."[240] While in 1988 EPA did not believe that the oil and gas industry would develop new waste management technologies, its belief has proved to be incorrect.

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[233] Hannah Wiseman, *Untested Waters: The Rise of Hydraulic Fracturing in Oil and Gas Production and the Need to Revisit Regulation*, 20 FORDHAM ENVTL. L. REV. 115, 124 (2009) (citing Texas Railroad Commission, Newark, East (Barnett Shale), Drilling Permits Issued (1993–2007)).
[234] Texas Railroad Commission, Newark, East (Barnett Shale) Field, Drilling Permits Issued (1993–2009).
[235] Daniel Cusick, *Industry Sets Record for Drilling, Well Completions*, LAND LETTER, Jan. 18, 2007.
[236] Am. Petroleum Inst., "U.S. Q1 drilling & completion estimates at 21-year high—API," Apr. 26, 2007.
[237] DIV. OF OIL, GAS AND MINING, UTAH DEP'T OF NATURAL RES., PRODUCED WATER DISPOSAL, graph slide 6 (2007).
[238] EPA REGION 8, *supra* note 28, at fig. 3-9.
[239] 53 FED. REG. at 25446-01, 25456.
[240] *Id.* at 25,451. EPA's Report to Congress indicates that EPA did not truly believe this assertion that it made in the 1988 Regulatory Determination: "Long-term improvements in waste management need not rely, however, purely on increasing the use of better existing technology. The Agency does foresee the possibility of significant technical improvements in future technologies and practices." EPA, REPORT TO CONGRESS, MANAGEMENT OF WASTES FROM THE EXPLORATION, DEVELOPMENT, AND PRODUCTION OF CRUDE OIL, NATURAL GAS, AND GEOTHERMAL ENERGY III-2 (1987)

Evidence since 1988 demonstrates that new technologies and practices are available and that the use of these safer practices often results in significant cost savings. In 2008, EPA itself stated that "It has been 20 years since the RCRA exemption for oil and gas exploration and production was implemented, and many practices and chemicals used have changed during that time,"[241] and has noted that many safer drilling fluids have been developed[242] and the use of alternatives to pits has become increasingly practical.[243] In addition to the savings that can result from the use of these new disposal methods, companies using safer disposal practices also obtain cost benefits by preventing pollution in the first place, as opposed to being allowed to use "cheaper" practices and later required to clean up the damage they create.[244] The State of New Mexico found that drilling activity more than doubled in the year immediately following establishment of more protective rules for oil and gas waste pits.[245]

It is time for EPA to require oil and gas companies to use these new, safer technologies.

a. New Waste Disposal Technologies

Safer disposal methods for E&P wastes have been developed since 1988. Although EPA acknowledged that such developments were likely in its 1987 Report to Congress, it chose not to require the use of then-emerging safer technologies because it believed that requiring their use would be prohibitively expensive for the oil and gas industry. Recent cost analyses indicate that those fears were unfounded; in many instances, the use of more environmentally sound disposal practices actually saves oil and gas companies money. For example, a study conducted in New Mexico found that eliminating pits, traditionally considered the cheapest disposal method, is actually more cost-effective than their continued use.[246]

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[241] EPA REGION 8, *supra* note 28, at 3–13.
[242] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006, at 29 (2000).
[243] EPA, REGION 8, OIL AND GAS ENVIRONMENTAL ASSESSMENT REPORT 1996–2002 13 (2003).
[244]

> [W]e've had testimony through here that the costs of remediation are, you know, in the hundreds of thousands to, typically millions of dollars. And there's a huge cost benefit to business to prevent pollution versus us allowing them to pollute water and then come back and require them to clean it up. I think that's really a disservice to industry, not to help them prevent that from occurring.

Statement of Commissioner William Olson before the New Mexico Oil Conservation Division, Apr. 16, 2008, OCD Document Image 14015_657_CF[1] at 30.
[245] Press Release, State of New Mexico, Governor Bill Richardson Announces Oil and Gas Drilling Activity in New Mexico Is Strong: Environmental regulations are not driving business away (May 19, 2010).
[246] DORSEY ROGERS, GARY FOUT & WILLIAM A. PIPER, NEW INNOVATIVE PROCESS ALLOWS DRILLING WITHOUT PITS IN NEW MEXICO (2006).

An Oil and Gas Accountability Project (OGAP) analysis demonstrates that closed-loop drilling systems, which use storage tanks and other equipment instead of pits, are cost-effective and can save money compared to conventional waste management with pits.[247] Mary Ellen Denomy, an expert in petroleum accounting, testified before the New Mexico Oil Conservation Division and reported her findings that the costs associated with a typical closed loop drilling system, also known as a pitless drilling system, are only 3.58% of total drilling costs, a significant reduction from the costs associated with typical on-site pit burial (6.58% of total drilling costs) and digging up and hauling wastes to a centralized facility (9.38% of total drilling costs).[248] While initial costs may be higher, closed-loop drilling systems create long-term savings because there is no need to construct pits, drilling waste can be dramatically reduced, water use can be reduced by as much as eighty percent, truck traffic is reduced by as much as seventy-five percent, and tanks can be reused.[249] Comparisons have found closed-loop drilling can result in a cost savings of up to $180,000 per pit,[250] and a project in New Mexico found that:

> [T]he average cost of using a pit and hauling the waste elsewhere for disposal is about 45% more compared to following the same process without a reserve pit. Moreover, the analysis showed that burying the waste on-site costs about 24% more when using a reserve pit as opposed to employing the closed-loop system.[251]

Individual case studies provide further support for these conclusions. A survey of Prima Energy Corporation's closed-loop system in Colorado indicated that closed-loop drilling could be more cost effective than conventional rotary drilling with reserve pits.[252] Prima Energy Corporation drilled over 68 wells in Colorado using closed-loop systems and compared their costs to the costs of using conventional rotary drilling with reserve pits.[253] The closed-loop drilling systems' average cost was $15,600 compared to conventional rotary drilling's cost of $17,020.[254] The study further demonstrated that closed-loop drilling systems result in significant waste minimization. Conventional rotary drilling was found to generate 5,200 barrels more barrels of produced water than closed-loop drilling.[255]

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[247] Oil & Gas Accountability Project, Alternatives to Pits.
[248] Oil & Gas Accountability Project, Closing Argument and Proposed Changes to Proposed Rule 50, *Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc.*, Dec. 10, 2007, at 10.
[249] Oil & Gas Accountability Project, *supra* note 247.
[250] *Id; see also* ROGERS ET AL., *supra* note 246, at 4–5.
[251] Dorsey Rogers, Dee Smith, Gary Fout & Will Marchbanks, *Closed-loop drilling system: A Viable Alternative to Reserve Waste Pits*, WORLD OIL, Dec. 2008, at 46.
[252] *See* Oil & Gas Accountability Project, *supra* note 247.
[253] Exhibit 8, Closed-Loop Drilling Case Studies, *Re: Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc.*, OCD Document Image No. 14015_637_[CF]1.
[254] *Id.*
[255] *Id.*

Similarly a study of two wells drilled two hundred feet apart in Matagorda County, Texas provides further support for assertions that closed-loop drilling systems can provide cost savings.[256] In Matagorda County, two wells were drilled two hundred feet apart "through the same formations, using the same rig crew, mud company and bit program."[257] One well used a closed-loop system while the other used traditional solids-control equipment. The closed-loop system "resulted in some significant savings" including: a forty-three percent savings in drilling fluid costs, twenty-three percent fewer rotating hours, fewer days to drill the wells to comparable depths, a thirty-seven percent reduction in bits used, and up to thirty-nine percent improvement in penetration rates.[258]

EPA's own studies confirm that closed-loop drilling systems are a safer and cost-saving waste disposal process.[259] Because of these types of findings, EPA has promoted the use of closed-loop drilling systems in Region 8.[260] The RRC of Texas has confirmed that closed-loop systems can result in significant cost savings;[261] and many other government agencies also support the use of closed-loop drilling systems.[262] In addition to the already demonstrated economic advantages of closed-loop systems, there is a great likelihood that the costs of constructing closed-loop systems will decrease even more in the future "as economies of scale and innovations in operations" continue to occur.[263] If these systems are manufactured in the United States, they add the benefit of new job creation in addition to lower environmental risk.

Although safer and economical, even closed loop systems can leak or spill. Strong regulations are required to govern the storage and transport of toxic waste. In some cases, waste may be transported via pipeline to storage or disposal sites. Yet in Texas, State officials declared at a public meeting that the state has no "rule-making authority" over such pipelines.[264]

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256 *Id.*
257 *Id.*
258 *Id.*
259 EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006, at 69 (2000).
260 EPA REGION 8, AN ASSESSMENT OF THE ENVIRONMENTAL IMPLICATIONS OF OIL AND GAS PRODUCTION: A REGIONAL CASE STUDY 4-4 (Working Draft 2008).
261 Abrahm Lustgarten, *Underused Drilling Practices Could Avoid Pollution*, PROPUBLICA, Dec. 14, 2009.
262 U.S. Fish & Wildlife Serv., *Wildlife Mortality Risk in Oil Field Waste Pits*, U.S. FWS CONTAMINANTS INFORMATION BULLETIN (2000) (recommending the use of closed loop containment systems and elimination of open pits and ponds); BUREAU OF LAND MGT, THE GOLD BOOK: SURFACE OPERATING STANDARDS AND GUIDELINES FOR OIL AND GAS EXPLORATION AND DEVELOPMENT (4th ed. 2007). "To prevent contamination of ground water and soils . . . it is recommended that operators use a closed-loop drilling system or line reserve pits with an impermeable liner." *Id.* at 17.
263 Controlled Recovery Inc.'s Written Closing Argument, *Re: Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc*., Dec. 10, 2007, at 3.
264 Lowell Brown, *Officials Give Few Answers to Argyle*, DENTON RECORD-CHRONICLE, Jan. 30, 2010.

b. Waste Minimization, Reuse, and Recycling Techniques

Waste minimization, reuse and recycling techniques also can be economical for companies. According to the RRC of Texas, "[w]aste minimization has been proven to be an effective and beneficial operating procedure," while recycling "is becoming a big business and more recycling options are available every day." [265] Both serve to reduce the total amount of E&P wastes that must be disposed and thereby decrease the risks associated with E&P wastes. In its manual *Waste Minimization in the Oilfield*, the RRC of Texas offers oil and gas companies more than one hundred ways to minimize wastes.[266] This manual, along with reports from individual companies implementing various waste minimization and recycling techniques, demonstrates that improved practices are possible.

Studies by the E&P Forum attest to the benefits of waste recycling[267] and identify several ways industry can reduce waste, "through process and procedure modifications . . . [For example,] improved solids control equipment and new technology can reduce the volumes [of drilling fluids] discharged to the environment, . . . more effective drillbits can reduce the need for chemical additions, [and] gravel packs and screens may reduce the volume of formation solids/sludge produced."[268] An analysis by OGAP found that the use of closed-loop drilling systems, in addition to providing cost benefits, maximizes the ability to reuse and recycle drilling fluids.[269] And waste reduction is not just beneficial from an environmental perspective. It can provide further opportunities for the oil and gas industry to save money. A study on land owned by the U.S. Army Corps of Engineers in Oklahoma found that a reduction in "wastes by close to 1.5 million pounds" resulted in "[a] material and disposal cost savings of $12,700."[270]

Both the government and industry are aware of the cost saving opportunities associated with the use of waste minimizing technologies and recycling and reuse projects. For example, STW Resources has developed a technology for use in the Barnett Shale that can reclaim approximately seventy percent of the flowback water produced by hydraulic fracturing operations in the region and thereby reduce the total amount of waste associated with hydraulic fracturing while also enabling the wastes to be reused.[271] And in July of 2008, the RRC of Texas approved Devon Energy's "third pilot program to treat and reuse frac fluid . . . . As a result of its water recycling efforts, Devon is the industry leader in water recycling and now used recycled

[265] Railroad Commission of Texas, *supra* note 52.
[266] DRILLING DOWN, *supra* note 20, at 29.
[267] E&P FORUM, *supra* note 107, at14 ("There are potential benefits in the sale of recovered hydrocarbons. All hydrocarbon wastes should be returned to the production stream where possible.").
[268] UNEP E&P FORUM, ENVIRONMENTAL MANAGEMENT IN OIL AND GAS EXPLORATION AND PRODUCTION: AN OVERVIEW OF ISSUES AND MANAGEMENT APPROACHES 54 (1997).
[269] Oil & Gas Accountability Project, *supra* note 247.
[270] Exhibit 8, Closed-Loop Drilling Case Studies, *Re: Case 14015: Application of New Mexico Oil Conservation Division for Repeal of Existing Rule 50 Concerning Pits, etc.*, OCD Document Image No. 14015_637_[CF]1.
[271] STW RES., INC., CONTAMINATED WASTE WATER RECLAMATION OPPORTUNITIES 2–3.

frac water at one out of every 10 frac jobs in its Barnett Shale operations."[272] Devon's wastewater recycling program "is projected to produce 75 percent reusable fracture fluid and 25 percent high concentrate and solids. The concentrate will be used as a drilling fluid or disposed of in an authorized facility."[273] Devon Energy Production Central Division's vice president estimated that "[a]t full treatment capacity, up to 85 percent of [the] water [Devon] recover[s] from fracture completions in the Barnett Shale could be reused." [274] And Devon Energy is not alone: Fountain Quail Water Management, DTE Gas Resources Inc., Burlington Resources, and Stroud Energy have all engaged in reuse and recycling efforts.[275]

New projects are underway at the national level: the U.S. Department of Energy's National Energy Technology Laboratory launched nine new projects in October 2009 focused on developing new technologies "to improve management of water resources, water usage, and water disposal."[276] These projects add to the fifteen already underway that are focused on "assess[ing] options and technologies for handling, cleaning, and reuse of produced and flowback water" in the Barnett and Appalachian shale plays.[277] When combined with pitless drilling through a closed-loop system, recycling of waste is clearly an effective, available, and economical way to manage E&P waste more safely and allow for compliance with stronger regulations.

c. <u>New Substitutes for Toxic Materials</u>

Studies indicate that the use of less toxic drilling and hydraulic fracturing fluids can both reduce the risks associated with E&P wastes and also reduce oil and gas companies' liability, thus potentially saving them money in the long run.[278] Other agencies confirm EPA's findings on the benefits of using safer cost effective alternatives. Numerous agencies encourage operators "to substitute less toxic, yet equally effective products for conventional drilling products."[279] And most recently, ExxonMobil announced that it "'supports the disclosure of the identity of the ingredients being used in fracturing fluids.'"[280] OGAP sees ExxonMobil's statement as a "significant step" and believes that "[o]nce the chemicals are widely known . . . companies will

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[272] News Release, Railroad Commission of Texas, Commissioners Approve of Devon Water Recycling Project for the Barnett Shale, July 29, 2008.
[273] *Id.*
[274] *Energy Companies Strive to Reuse Water*, WEATHERFORD TELEGRAM, July 25, 2007, at 3C.
[275] *Id.*
[276] U.S. Dep't of Energy, National Energy Technology Lab, *Nine New Projects*, OIL & GAS PROGRAM NEWSLETTER (Dep't), Winter 2009, at 8.
[277] *Id.* at 6.
[278] EPA OFFICE OF COMPLIANCE SECTOR NOTEBOOK PROJECT, PROFILE OF THE OIL AND GAS EXTRACTION INDUSTRY, EPA/310-R-99-006 (2000).
[279] BUREAU OF LAND MGT, THE GOLD BOOK: SURFACE OPERATING STANDARDS AND GUIDELINES FOR OIL AND GAS EXPLORATION AND DEVELOPMENT, at 39 (4th ed. 2007).
[280] Katie Burford, *ExxonMobil Favors Fracing Disclosure, Environmental Group Welcomes Position from Oil Industry Giant*, DURANGO HERALD, Apr. 19, 2010.

be more likely to use green alternatives" which will result in "a lessening of the toxicity of the fluids" over time.[281]

In addition, the search for chemicals with lower potential environmental impacts has "result[ed] in the generation of less toxic wastes . . . . [For] example . . . mud and additives that do not contain significant levels of biologically available heavy metals or toxic compounds."[282] These types of new synthetic drilling fluids already have been developed and are less toxic, "free of polynuclear aromatic hydrocarbons and have . . . faster biodegradability and lower bioaccumulation potential."[283] Safer alternatives to current drilling fluids are available—all that remains is for the oil and gas industry to adopt widespread use of them.

Industry has already proven itself to be capable of switching to less hazardous compounds in the past. In the 1990s many drilling companies voluntarily phased out the use of benzene in their operations.[284] EnCana stopped using a chemical, 2-Butoxyethanol, linked with reproductive problems in animals, while BJ Services, "one of the largest fracturing service providers in the world, has discontinued the use of fluorocarbons, a family of compounds that are persistent environmental pollutants." [285] Schlumberger has developed "GreenSlurry," which the company claims is "earth-friendly."[286] Antero Resources Corporation pledged to use only "green frac" materials in the communities of Rifle, Silt and New Castle in western Colorado.[287] Yet these reported less toxic fluids are not used everywhere. While the oil and gas industry clearly has the capability to adapt its operations to safer technologies, most companies have been reluctant to make such changes. EPA should thus act and require the oil and gas industry to expand the use of the safer, less toxic drilling fluids that are currently available.

5. Oil and Gas Waste Meets the Statutory and Regulatory Criteria for Hazardous Waste.

Absent their special exclusion from RCRA, E&P wastes would properly be regulated under Subtitle C of RCRA. Congress defined hazardous wastes under RCRA as:

> [A] solid waste, or combination of solid wastes, which because of its quantity, concentration, or physical, chemical or infectious characteristic may—

[281] *Id.*
[282] E&P FORUM, *supra* note 107, at12-23.
[283] Drilling Waste Management Information System, Drilling Waste Management Fact Sheet: Using Muds and Additives with Lower Environmental Impacts.
[284] Susan Riha et al., *supra* note 42, at 6.
[285] Lustgarten, *supra* note 261.
[286] Schlumberger, "Earth-friendly GreenSlurry system for uniform marine performance," March, 2003.
[287] The Rifle, Silt, New Castle Community Development Plan, Jan. 1, 2006.

> (A) cause, or significantly contribute to an increase in mortality or an increase in serious irreversible, or incapacitating reversible, illness; or
> (B) pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, or disposed of, or otherwise managed.[288]

Under RCRA, Congress instructed EPA to "define hazardous waste using two different mechanisms: by listing certain specific solid wastes as hazardous . . . and by identifying characteristics . . . which, when exhibited by a solid waste, make it hazardous."[289] Under RCRA, "[c]haracteristic wastes are wastes that exhibit measurable properties which indicate that a waste poses enough of a threat to warrant regulation as a hazardous waste."[290] The four technical criteria EPA uses to determine if a waste is a characteristic waste include:[291] ignitability, corrosivity, reactivity, and toxicity.[292] Waste will be considered hazardous if it exhibits *any* of the four characteristics.[293] Because various types of E&P wastes exhibit several of these characteristics, E&P wastes should properly be regulated under Subtitle C of RCRA as characteristic hazardous wastes.

a. <u>Ignitability</u>

Ignitability is a criterion used to identify wastes that "can readily catch fire and sustain combustion."[294] A substance's flashpoint is indicative of its ignitability.[295] A waste's flash point is "the lowest temperature at which the fumes above a waste will ignite when exposed to flame."[296] Eleven percent of oily sludges sampled in California had a flash point exceeding the regulatory threshold.[297]

The risks associated with E&P wastes having hazardous flashpoints under RCRA's criteria have been demonstrated in the past decade. In January 2003, a fire occurred when hydrocarbon vapor from basic sediment and water, a type of E&P waste, ignited at a Texas open area collection pit.[298] Three people were killed in the fire and four others were severely burned.[299] In

[288] 42 U.S.C. § 6903(5).
[289] EPA, RCRA ORIENTATION MANUAL, CHAPTER III: RCRA SUBTITLE C—MANAGING HAZARDOUS WASTE, at III-17.
[290] *Id.* at III-22.
[291] Hazardous Waste Treatment Council v. U.S. EPA, 861 F.2d 277, 279 (D.C. Cir. 1988).
[292] *See* 40 CFR § 261.20 et seq.
[293] *Id.*
[294] EPA, *supra* note 2899, at III-22.
[295] NAGY, *supra* note 24, at 36.
[296] EPA, *supra* note 2899, at III-23.
[297] NAGY, *supra* note 24, at 31.
[298] U.S. Dep't. of Labor, Occupational Safety & Health Admin., Potential Flammability Hazard Associated with Bulk Transportation of Oilfield Exploration and Production (E&P) Waste Liquids, SHIB-03-24-2008.
[299] *Id.*

May 2006, a natural gas condensate tank and pit caught on fire in Colorado.[300] Nearby residents were described as "'terrified' by the 200-foot flames."[301] Residents were also concerned because they were not able to learn what potential health impacts they were exposed to from the burning waste "since neither the company nor local or state authorities bothered taking air quality samples during the blaze."[302]

More recently, a wastewater impoundment pond in Washington County, Pennsylvania caught fire.[303] George Zimmerman reported seeing "flames shooting 100 feet in the air" at the fire that occurred at the hydraulic fracturing site located on his property.[304] A state police fire marshal determined that the fire was an accident caused by "a malfunction [that] ignited fumes [most likely in the frac tank] and caused $375,000 in damages."[305] The fire also "badly damaged" the frac pit liner, causing a spokeswoman from the Pennsylvania DEP to be concerned that the pit's contents might escape.[306] Instances such as these fires and the sampling data from California indicate that E&P wastes are ignitable, and that this characteristic of E&P wastes has resulted in serious harm. E&P wastes with these flash points would appropriately be regulated as characteristic hazardous wastes under Subtitle C of RCRA. Such regulation is necessary to prevent future incidents similar to the January 2003 and March 2010 fires.

b. <u>Corrosivity</u>

Waste is corrosive if "it is acqueous and has a pH less than or equal to 2 or greater than or equal to 12.5" or if "[i]t is a liquid and corrodes steel . . . at a rate greater than 6.35 mm per year."[307] Drilling wastes sampled in California had elevated pH levels approaching the 12.5 regulatory limit.[308] In addition, corrosive chemicals are frequently found in E&P wastes. For example, hydrogen sulfide is a corrosive and "toxic gas occurring naturally in some oil and gas reservoirs."[309] The corrosive characteristics of E&P wastes have already been responsible for many incidents where E&P wastes have been improperly released. On numerous occasions, spills of E&P wastes have been reported as originating from corroded equipment that had begun to leak because of corrosion attributed to the substances the equipment contained.[310] Again, because a waste is properly regulated under Subtitle C of RCRA when it exhibits *any* of the four

[300] OIL & GAS ACCOUNTABILITY PROJECT, SPRING/SUMMER 2006 REPORT (2006).
[301] *Id.*
[302] *Id.*
[303] Janice Crompton, *Residents Reported Gas Odors Before Explosion*, PITTSBURGH POST-GAZETTE, Apr. 1, 2010, at B-1.
[304] Kathie O. Warco, *Fumes Ignite at Gas Well*, OBSERVER-REPORTER, Apr. 1, 2010.
[305] *Id.*
[306] *Id.*
[307] 40 CFR § 261.22.
[308] NAGY, *supra* note 24, at 37.
[309] E&P FORUM, *supra* note 107, at28.
[310] *See supra* note 216 and accompanying text.

criteria of characteristic hazardous wastes, corrosive E&P wastes should be regulated under Subtitle C.

c. Reactivity

A waste is reactive if "(1) it is normally unstable and readily undergoes violent change without detonating, (2) [i]t reacts violently with water, (3) [i]t forms potentially explosive mixtures with water, (4) [w]hen mixed with water, it generates toxic gases, vapors or fumes in a quantity sufficient to present a danger to human health or the environment, (5) [i]t is a cyanide or sulfide bearing waste which, when exposed to pH conditions between 2 and 12.5, can generate toxic gases, vapors or fumes in a quantity sufficient to present a danger to human health or the environment, (6) [i]t is capable of detonation or explosive reaction if it is subjected to a strong initiating source or if heated under confinement, (7) [i]t is readily capable of detonation or explosive decomposition or reaction at standard temperature and pressure, [or] (8) [i]t is a forbidden explosive . . . ."[311]

Out of the four criteria for determining characteristic hazardous wastes, reactivity is the most difficult to test: "In many cases, there is no reliable test method to evaluate a waste's potential to explode, react violently, or release toxic gas under common waste handling conditions."[312] In some cases, a waste's reactivity can be evaluated by a releasable sulfide test.[313] Although no regulatory threshold valuable for releasable sulfides has been established, EPA established an interim guidance value.[314] Testing of E&P wastes in California found samples of sludge and tank bottoms exceeding EPA's interim guidance value.[315]

d. Toxicity

The Code of Federal Regulations describes the specific levels/concentrations at which various chemicals will be considered toxic for the purposes of RCRA. To determine whether a chemical meets the required level, EPA uses the Toxicity Characteristic Leaching Procedure (TCLP). Many E&P wastes would be considered toxic under this test. The New Mexico Oil Conservation Division (OCD) found that several samples taken from E&P waste disposal pits in the state contained levels of chemicals that failed the TCLP test.[316] Specifically, the OCD found pits that contained levels of arsenic, lead, mercury, 2,4-Dinitrotoluene, and 2-Methylnaphthalene that exceeded TCLP levels.[317] Its report indicated that the levels of lead they found alone would have allowed the wastes to be considered characteristically hazardous if not for the RCRA

[311] 40 CFR § 261.23.
[312] EPA, *supra* note 2899, at III-23.
[313] NAGY, *supra* note 24, at 38.
[314] *Id.*
[315] *Id.* at 38–39.
[316] *See* Earthworks, OCD's 2007 Pit Sampling Program: What Is in that Pit?, at 31.
[317] *Id.* at 34.

exemption.[318] Analysis of E&P waste in California determined that both produced water and oily sludge met the federal toxicity characteristic and would be considered hazardous, again, if not for the RCRA exemption.[319] Because of this evidence, and the multitude of evidence discussed above indicating that E&P wastes have caused, and present substantial risk of continuing to cause, hazards to human health and the environment, EPA should reconsider its 1988 Regulatory Determination and regulate E&P wastes under Subtitle C of RCRA, as would be proper given the fact that they frequently exhibit the same traits as characteristic hazardous wastes.

II. REQUEST FOR PROMULGATION OF REGULATIONS

The Petitioner, the Natural Resources Defense Council, respectfully requests that the EPA promulgate regulations classifying wastes from the exploration, development and production of oil and natural gas as hazardous waste subject to provisions of Subtitle C of RCRA. This request is based on overwhelming evidence that waste from the exploration, development and production of oil and natural gas is hazardous, taking into account its toxicity, corrosivity, and ignitability, that it is released into the environment where it can cause harm, that state regulations are inadequate, and that there are numerous methods available to manage it as hazardous waste. As set forth in this Petition, evidence exists for EPA to document that, because of its quantity, concentration, and chemical characteristics, E&P waste may cause or significantly contribute to an increase in mortality and serious incapacitating illness and that it may pose a substantial present or potential hazard to wildlife and the environment when improperly treated, transported or disposed of, or otherwise managed, as is occurring throughout the U.S. in the absence of sufficient mandatory federal oversight. *See* 42 U.S.C. § 6902(4)-(5).

The Petitioner requests that the EPA consider the relevant statutory and regulatory factors, as well as the factors set forth in the July 1988 Regulatory Determination, and promulgate regulations applying to wastes from the exploration, development and production of oil and natural gas under Subtitle C of RCRA.

Respectfully submitted this 8th day of September, 2010.

[318] *Id.* at 35.
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Ohio Quakes Probably Triggered by Waste Disposal Well, Say Seismologists

January 6, 2012

A tower for removing gas at the Marcellus Shale Formation in Pennsylvania. Credit: Ruhrfisch/Wikimedia Commons.

Earthquakes that have shaken an area just outside Youngstown, Ohio in the last nine months—including a substantial one on New Year's Eve—are likely linked to a disposal well for injecting wastewater used in the hydraulic fracturing process, say seismologists at Columbia University's **Lamont-Doherty Earth Observatory** who were called in to study the quakes. Ohio Gov. John Kasich has shut down the injection well and put four other proposed wells on hold. In the meantime, steps have been taken to ease pressure in the well to avert further rumblings.

The concern comes as natural gas drilling in shale formations that underlie much of the Northeast grows. To extract the gas, a mix of water, sand and chemicals is pumped under high pressure into shale rocks, in a process called hydraulic fracturing, or fracking. Once the gas has been removed, wastewater is either recycled or trucked off-site and injected deep underground. As the pressurized water seeps through cracks deep below ground, it can sometimes cause earthquakes on ancient fault lines.

Ohio is home to 177 such disposal wells, including the Youngstown well, which lies in a seismically dormant region bordering Pennsylvania. The first rumblings surfaced in March, several months after injection of fracking waste from Pennsylvania began. Nine small temblors followed. In late November, Ohio authorities asked Lamont scientists to monitor the area with mobile instruments that could provide a more accurate location of subsequent earthquakes. On Dec. 24, the four instruments recorded a magnitude 2.7 quake 2.2 miles below the surface–a half-mile away and about 2,000 feet below the 1.7 mile deep well.

"The location of the earthquake was sufficient evidence that there could be a link," Lamont seismologist **John Armbruster** told **NPR's All Things Considered**. Later in the week, D&L Energy, which owns the site, agreed to shut down the well. Then, on Dec. 31, a magnitude 4.0 quake struck. The Lamont instruments located it at about 300 feet east, and some 500 feet under the previous event. A 4.0 is about 40 times more powerful than a 2.7. At that point, the state put a moratorium on activity on four other wells within a five-mile radius, all of them already inactive.

Hydrofracking by its nature causes tiny earthquakes, because it involves fracturing of rock—but these are largely imperceptible, as the process takes place in relatively weak, shallow shales that crack before building up much strain. Quakes triggered by waste injection wells can be potentially more powerful because more fluid is usually being pumped underground at a site for longer periods, said **Roger Anderson**, an energy geophysicist at Lamont-Doherty who is not involved in the study. Once fluid enters a preexisting fault, it can pressurize the rocks enough to move; the more stress placed on the rock formation, the more powerful the earthquake. The Lamont data suggests that the Dec. 31 movement near the Ohio well was a strike-slip motion, in which one rock face slides across the other horizontally.

The chance of triggering an ancient fault by injecting fluid underground is relatively slim—maybe one in 200, said Lamont seismologist **Won-Young Kim**, who heads the **Lamont-Doherty Cooperative Seismic Network**. But, he said, the potential damage and injuries from an earthquake could far outweigh the cost of closing the well. "Once you get one earthquake, it's better to stop then, because you may get another," he said. That point was echoed by Armbruster on NPR: "I would advocate monitoring of wells to know when triggering of earthquakes first begins," he said. "Then you can decide whether to continue using that well."

Seismologists have known about the potential for injection wells to trigger earthquakes since the 1960s, when injected wastewater from weapons production at the Rocky Mountain Arsenal in Colorado was tied to a **series of earthquakes** including several of magnitude 5.0 or greater that caused minor damage in Denver and other cities. Earthquakes in Arkansas, Texas, Oklahoma and the United Kingdom have been linked in recent years to disposal of fracking fluids. In 2001, scientists linked a magnitude 4.2 quake in Ashtabula, Ohio to a waste disposal well there, a "carbon copy" of the recent activity near Youngstown, said Kim.

After the New Year's quake, Kim said that the risk could continue for another year or two, as it could take that long for pressurized fluid to dissipate. To minimize that risk, Ohio officials announced Jan. 5 that they would start letting the injected fluids bubble back into storage tanks at the surface rather than capping the well under standard procedures.
The Lamont-Doherty scientists will continue to monitor the area with colleagues from Youngstown State University and Ohio Geological Survey. They are also talking with the university about upgrading its own seismic station.

More:
Watch how injected fluids trigger an earthquake in **this video** from Next media Animation.
For ongoing coverage of the scientific debate over hydrofracking see Scientific American's **Storify blog.**

Related Projects:

Lamont Cooperative Seismographic Network (LCSN)

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THE WALL STREET JOURNAL.
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BUSINESS | November 3, 2011

Study Ties Fracking to Quakes in England

By ALEXIS FLYNN

LONDON—The company leading efforts to unlock the U.K.'s potentially vast shale-gas reserves suffered a setback Wednesday after a report found it was "highly probable" a controversial production technique caused two small earthquake tremors in the country earlier this year.

The report, which was financed by U.K. energy company Cuadrilla Resources Ltd., pointed to "strong evidence" that the two minor earthquakes and 48 weaker seismic events resulted from Cuadrilla's pumping drilling fluids used in hydraulic fracturing, or "fracking." At the same time, the report said the events were the result of a "rare combination of geological factors."

Bloomberg News

Cuadrilla Resouces' shale gas exploration site, in July.

The report could complicate efforts by privately held Cuadrilla to resume hydraulic-fracturing activity that was halted after the two seismic incidents.

The company said the report concluded that none of the events recorded, including one in April of 2.3 and one in May of 1.5 on the Richter scale, had any structural impact on the surface above.

The U.K. has become the latest venue in Europe to see shale gas spur major debate over fracking, which has been heavily criticized by environmental groups. In June, France became the first country to ban shale-gas exploration.

More

Cuadrilla statement

Earlier: U.K. Gets Big Shale Find

The Staffordshire, England-based company said the report vindicated its stance that its operations pose "no threat to people or property in the local area," but it pledged to implement an early-warning system and other recommendations to mitigate the risk.

Cuadrilla in September announced a big shale-gas discovery, but development is on hold after the company and government agreed in June to stop its shale-gas test drilling until its potential consequences were better understood.

U.K. regulators said they would review the findings before shifting policy. Leading environmental groups and local-government officials also called for caution on fracking, which has been a key component in the rise of shale gas in the U.S. and other areas.

The U.K. Department of Energy and Climate Change will study the implications of the report, a department spokesman said. "The implications of this report will be reviewed very carefully—in consultation with the British Geological Survey, independent experts, and the other key regulators," said the spokesman.

The report found that the combination of geological factors that caused the quakes was rare and would be unlikely to occur together again at future well sites.

"If these factors were to combine again in the future, local geology limits seismic events to around magnitude 3 on the Richter scale as a worst-case scenario," the report said.

The Richter scale measures magnitude, which is expressed in whole numbers and decimal fractions, and not damage caused. Each whole number represents a tenfold increase in measured amplitude, so a 5.3 tremor might be rated moderate, while a strong earthquake could be recorded at 6.3.

Cuadrilla said the report was overseen by an independent team of seismic experts and was prepared in consultation with the Department of Energy and Climate Change. A department spokesman said the report was commissioned by the company and that it would comment on the substance of the conclusions after it studied the report's findings.

An earlier study by the British Geological Survey put the epicenter for each earthquake as being 500 meters (1,650 feet) away from the Preese Hall-1 well, at Weeton, near Blackpool, England.

British Geological Survey Earthquake Seismologist Dr. Brian Baptie said Wednesday's report confirmed his organization's own initial conclusion that fracking was responsible for the earthquakes. "It seems quite possible, given the same injection scheme in the same well, that there could be further earthquakes," he said.

Dr. Baptie said a way to minimize future risks could include the type of traffic-light monitoring system proposed by Cuadrilla but pointed out that even an "acceptable magnitude 2.6 earthquake might, at a depth of three kilometers (1.9 miles), result in an intensity of shaking that would not be expected to cause any damage but would be widely felt by people indoors and out, and may displace objects on shelves."

Spotting these types of seismic events could also be tricky, explained Dr. Baptie. "Earthquakes such as this result from very small movements on small faults that may be very difficult to identify," he said.

Nick Molho, head of energy policy at environmental group WWF-UK, said the findings "are worrying, and are likely to add to the very real concerns that people have about fracking and shale gas."

Local Liberal Democrat Councillor Sue McGuire, who also leads a residents' group opposed to fracking, said that if Cuadrilla drilled the 400 to 800 wells proposed than "we cou ld be looking at significant seismic activity in the area, which could have major impact on peoples' homes and businesses in the area, not to mention the impact on the environment."

"A moratorium would give the government time to ensure that industry specific legislation can be put in place," she said.

Cuadrilla has said some 200 trillion cubic feet of shale gas may be contained in northwest England,enough to meet the country's gas demand for 64 years, although it has cautioned the actual recoverable figure may be much lower.

—Guy Chazan contributed to this article.

Write to Alexis Flynn at alexis.flynn@dowjones.com

Corrections & Amplifications
An earlier version of this story erroneously referred to a Cuadrilla estimate of 200 million feet of gas in northwest England; the estimate is for 200 trillion cubic feet of gas.

ARE SEISMICITY RATE CHANGES IN THE MIDCONTINENT NATURAL OR MANMADE?

ELLSWORTH, W. L., US Geological Survey, Menlo Park, CA; HICKMAN, S. H., US Geological Survey, Menlo Park, CA; LLEONS, A. L., US Geological Survey, Menlo Park, CA; MCGARR, A., US Geological Survey, Menlo Park, CA; MICHAEL, A. J., US Geological Survey, Menlo Park, CA; RUBINSTEIN, J. L., US Geological Survey, Menlo Park, CA

A remarkable increase in the rate of M 3 and greater earthquakes is currently in progress in the US midcontinent. The average number of M >= 3 earthquakes/year increased starting in 2001, culminating in a six-fold increase over 20th century levels in 2011. Is this increase natural or manmade? To address this question, we take a regional approach to explore changes in the rate of earthquake occurrence in the midcontinent (defined here as 85° to 108° West, 25° to 50° North) using the USGS Preliminary Determination of Epicenters and National Seismic Hazard Map catalogs. These catalogs appear to be complete for M >= 3 since 1970. From 1970 through 2000, the rate of M >= 3 events averaged 21 +- 7.6/year in the entire region. This rate increased to 29 +- 3.5 from 2001 through 2008. In 2009, 2010 and 2011, 50, 87 and 134 events occurred, respectively. The modest increase that began in 2001 is due to increased seismicity in the coal bed methane field of the Raton Basin along the Colorado-New Mexico border west of Trinidad, CO. The acceleration in activity that began in 2009 appears to involve a combination of source regions of oil and gas production, including the Guy, Arkansas region, and in central and southern Oklahoma. Horton, et al. (2012) provided strong evidence linking the Guy, AR activity to deep waste water injection wells. In Oklahoma, the rate of M >= 3 events abruptly increased in 2009 from 1.2/year in the previous half-century to over 25/year. This rate increase is exclusive of the November 2011 M 5.6 earthquake and its aftershocks. A naturally-occurring rate change of this magnitude is unprecedented outside of volcanic settings or in the absence of a main shock, of which there were neither in this region. While the seismicity rate changes described here are almost certainly manmade, it remains to be determined how they are related to either changes in extraction methodologies or the rate of oil and gas production.

Wednesday, April 18th / 3:45 PM Oral / Pacific Salon 4 & 5

SSA 2012

Session: The M5.8 Central Virginia and the M5.6 Oklahoma Earthquakes of 2011

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Pennsylvania Energy Impacts Assessment

Report 1: Marcellus Shale Natural Gas and Wind

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November 15, 2010

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1. The Nature Conservancy – Pennsylvania Chapter
2. Western Pennsylvania Conservancy – Pennsylvania Natural Heritage Program
3. Audubon Pennsylvania

The Nature Conservancy
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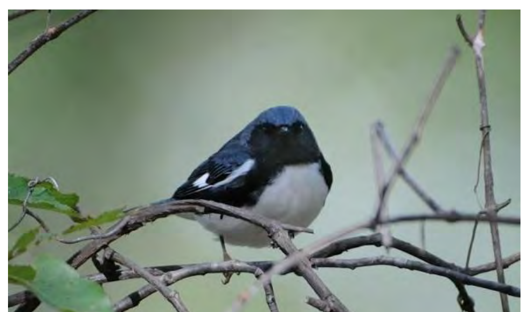
Executive Summary

Forest landscape along the West Branch Susquehanna River, Clinton County. © George C. Gress / TNC

Within a few weeks during the summer of 2000, eight towers rose two hundred feet above an agricultural field on a low ridge top along the Pennsylvania Turnpike. Not long after, large blades began sweeping the Somerset County sky as Pennsylvania's first industrial wind facility went on line. Several years later and an hour drive to the west, an unusual natural gas well was drilled over a mile down and pumped full of water. That well in Washington County yielded a surprising amount of gas flowing from fractures in a shale formation that geologists had long suspected held plenty of gas but has been too expensive to develop. Meanwhile, a Canadian company bought a small sawmill in Mifflintown and started producing wood pellets for stoves, boilers, and electric plants. It soon became one of the region's largest producers of wood biomass energy supplies. In the decade since, these three new energy technologies have expanded rapidly across the state. By the end of this year, 500 wind turbines will be turning on Pennsylvania ridgelines, nearly 2,000 Marcellus natural gas wells will be scattered across rolling fields and forests, and over 50 facilities will be producing wood pellets or burning wood for energy. Thousands of miles of pipelines and powerlines already crisscross the state to get energy supplies to major markets in the Northeast.



Black-throated blue warblers and other interior forest species could be impacted by forest fragmentation caused by energy development. © Gary Irwin

Each of these energy sources carries both promise and risk for people and nature. The promise is that wind, natural gas, and wood biomass energy can reduce greenhouse gas emissions, generate jobs, and increase energy security. The risk is that extensive land use change and loss of natural habitats could accompany new energy development and transmission lines. Impacts to priority conservation habitats across the state have been modest thus far. For example, aerial photo analysis indicates Marcellus gas development has so far cleared just 3,500 acres of forest (about 1,000 acres for wind turbines). An additional 8,500 acres of forest is now within 300 feet of new fragmenting edges created by well pads, and associated roads and infrastructure (5,000 acres for wind turbines). This fragmentation deprives "interior" forest species, such as black-throated blue warblers, northern goshawks, salamanders, and many woodland flowers, of the shade, humidity and tree canopy protection that only deep forest environments can provide.

By all accounts, each of these energy types is likely to grow substantially in Pennsylvania during the next two decades. The Marcellus shale formation, which underlies two-thirds of the state, is now believed to be one of the largest unconventional shale gas reserves in the world. The Pennsylvania Alternative Energy Portfolio Standards Act of 2004, along with state and federal incentives, will likely boost expansion of wind, wood biomass, and other alternative energy types over the next two decades. But, how much of each energy type might be developed? What transmission infrastructure will be needed to get more electric power and natural gas to consumers? And, where are these energy types most likely to be developed? How does the likely scale and location of future energy development overlap with priority conservation areas? The Pennsylvania Energy Impacts Assessment seeks answers to these questions so that conservationists can work more effectively with energy companies and government agencies to avoid, minimize or mitigate habitat impacts in the future.

Nine Mile Run Creek in PA's North Central Highlands © George C. Gress / TNC.

Assessment Goal: Develop credible energy development projections and assess how they might affect high priority conservation areas across Pennsylvania. Marcellus natural gas, wind, wood biomass, and associated electric and gas transmission lines were chosen as the focus since these energy types have the most potential to cause land-use change in the state over the next two decades. The conservation impacts focus is on forest, freshwater, and rare species habitats. The assessment **does not** address other potential environmental impacts, including water withdrawal, water quality, air quality and migratory pathways for birds and bats. The assessment also does not address a range of other social, economic, and climate characteristics of these energy types.

Key Assumptions: Any assessment of future trends must include certain assumptions. Among the most important assumptions of the Pennsylvania Energy Impacts Assessment are the following:

- A 20-year time period is used to assess potential cumulative habitat impacts from energy development;
- Given uncertainties about how energy prices could change, it was assumed that prices and capital investment (and policy and social conditions) will be sufficient to promote steady development growth for each energy type during the next two decades;
- Given uncertainty about how technology changes could affect spatial footprints, it was assumed that spatial footprints per well pad, turbine, and mile of transmission line will not change significantly during the next two decades;
- Given the proprietary nature of data on leases, Marcellus Shale porosity, fine resolution wind power, etc., all projections are based on publicly available information;
- It was assumed that recent trends and patterns of energy development will continue for the next two decades absent significant changes in government policies and industry practices;

Energy projections contained in this assessment are informed scenarios – **not predictions** – for how much energy development might take place and where it is more and less probable. Projected impacts, however, are based on measurements of actual spatial footprints measured for hundreds of well pads and wind turbines.

Analytical Steps: Key analytical steps for the Pennsylvania Energy Assessment included:

1) *Data collection* – Over 50 spatial data layers on energy resources, development permits, road and transmission infrastructure, physical features, and conservation priorities were compiled for the assessment;

2) *Spatial footprint analysis* – Spatial footprints for Marcellus gas well and wind turbine pads, associated roads, associated pipelines, associated electric transmission lines, and associated other clearings (*e.g.*, gas containment pits, equipment staging areas, electrical substations) were digitized using aerial photos of sites before and after construction;

3) *Scale projections* – Low, medium, and high scenarios for ***how much*** Marcellus Shale natural gas, wind, wood biomass, and transmission line development might occur were based as much as possible on existing projections and data from credible sources.

4) *Geographic projections* – Projections of ***where*** new Marcellus natural gas and wind energy development is more and less likely to occur were based on modeling the probability of a map pixel's land-use change to energy production based on sets of drivers and constraints developed for each energy type. Geographic projections for wood biomass and energy transmission were not modeled due to a lack of data. Conclusions about regional patterns of wood biomass and transmission development and potential conservation impacts will be presented in Report 2 of the Pennsylvania Energy Impacts Assessment.

5) *Conservation impacts analysis* – The potential impacts of future energy development were assessed for forest and freshwater habitats across the state. In addition, sites recognized as important for species of conservation concern were assessed. Conservation datasets for these assessments included, among others, large forest patches from The Nature Conservancy and the Western Pennsylvania Conservancy, habitat areas for rare species from the Pennsylvania Natural Heritage Program, densities for interior forest nesting bird species from the 2nd Pennsylvania Breeding Bird Atlas, and intact watersheds for native brook trout populations from the Eastern Brook Trout Joint Venture.

6) *Review* – A dozen energy experts in government, industry, and research organizations provided technical review of the energy projections.

Energy Projections: The Pennsylvania Energy Impacts Assessment developed low, medium and high scenarios for the amount of energy development that might take place in Pennsylvania by 2030. The projections include:

- *Marcellus Shale* – Sixty thousand wells could be drilled on between 6,000 and 15,000 new well pads (there are currently about 1,000), depending on how many wells are placed on each pad. Gas development will occur in at least half of the state's counties, with the densest development likely in 15 counties in southwest, north central, and northeast Pennsylvania.

- *Wind* – Between 750 and 2,900 additional wind turbines could be built (there are currently about 500), depending on the wind share of electric generation by 2030. Most turbines would be built along the Allegheny Front in western Pennsylvania and on high Appalachian ridgetops in the central and northeastern parts of the state.

- *Wood Biomass* – Wood biomass energy demand could double or even triple today's wood energy use, depending on whether and how many coal power plants co-fire with wood biomass. Wood biomass energy development is likely to be widespread across the state in all three scenarios.

- *Transmission Lines* – Preliminary findings indicate between 10,000 and 15,000 miles of new high-voltage power lines and gas pipelines (especially gathering lines) could be built during the next twenty years. There is considerable uncertainty about exactly where these lines will be built but recently proposed electric and gas transmission lines provide insights into potential habitat impacts.

Conservation Impacts: This first Pennsylvania Energy Impacts Assessment report focuses on the overlap between likely Marcellus gas and wind development areas and Pennsylvania's most important natural habitats. A second report will focus on the potential for additional impacts from new wood biomass energy plants, electric power lines, and natural gas pipelines. Key findings for impacts from Marcellus natural gas and for wind development include:

Forests. By 2030, a range of between 38,000 to 90,000 acres of forest cover could be cleared by new Marcellus gas development in the state. Forest clearing for the wind development scenarios is much smaller, ranging from 1,900 to 5,200 acres. Such clearings would create new forest edges where the risk of predation, changes in light and humidity levels, and expanded presence of invasive species could threaten forest interior species in 91,000 to 220,000 forest acres adjacent to Marcellus development and 13,400 to 36,000 forest acres adjacent to wind development. Forest impacts will be concentrated in the north central and southwest parts of the state where many of the state's largest and most intact forest patches could be fragmented into smaller patches by well pads, roads, and other infrastructure. Impacts to forest interior species will vary depending on their geographic distribution and density. Some species, such as the black-throated blue warbler, could see widespread impacts to their relatively restricted breeding habitats in the state while widely distributed species, such as the Scarlet Tanager, would be relatively less affected. Locating energy infrastructure in open areas or toward the outer edges of large patches can significantly reduce impacts to important forest areas.

Freshwater. Aquatic habitats are at risk too. Once widespread, healthy populations of native eastern brook trout in Pennsylvania are now largely confined to small mountain watersheds. Nearly 80 percent of the state's most intact brook trout watersheds could see at least some Marcellus gas and wind development during the next twenty years. Strongholds for brook trout are concentrated in north central Pennsylvania, where Marcellus development is projected to be relatively intensive in over half of the state's best brook trout watersheds. Exceptional Value streams – the Department of Environmental Protection's highest quality designation – could see hundreds of well pads (perhaps 300 - 750) and dozens of wind turbines (perhaps 50 – 200) located within one-half mile under the projections. Because many intact brook trout

Brook trout © TNC

and EV streams are in steep terrain, rigorous sediment controls, and possibly additional setback measures, are needed to help conserve these sensitive habitats.

Rare Species. Nearly 40 percent of Pennsylvania's globally rare and Pennsylvania threatened species can be found in areas with high potential for Marcellus gas development. These species tend to be associated with riparian areas, streams, and wetlands, while others are concentrated in unusually diverse areas such as the Youghiogheny Gorge. A handful of rare species have most or all of their known locations in high potential areas for Marcellus gas development. For example, three-fourths of all known snow trillium populations are in high potential Marcellus development areas as are all known populations for the green salamander. A much smaller number of known locations for globally and state rare species overlap with high potential wind development sites and they tend to be associated with rocky outcrops and ridgetop barrens habitats. Species with the greatest overlaps include timber rattlesnakes, Allegheny woodrats, and northern long-eared Myotis bats. More intensive surveys for globally rare and state critically endangered species in high potential Marcellus and wind development areas could help to minimize impacts before development begins. The Pennsylvania Game Commission is working with wind companies and other researchers to assess impacts to migratory pathways for birds and bats.

Recreation. Extensive overlaps are projected between Marcellus development and state forests, state parks, and state game lands. Just over ten percent of Pennsylvania's public lands are legally protected from gas development, most of it within State Wild and Natural Areas or in state parks where the Commonwealth owns the mineral rights. The state does not own mineral rights for 80% of State Park and State Game Lands, nearly 700,000 acres of State Forests have already been leased, and only about 300,000 acres of the remaining State Forest Lands are legally off-limits to future leases. Projections indicate between 900 and 2,200 well pads could be developed across all state lands, with most going on State Forest Lands, followed by State Game Lands, and State Parks. Wind development was not projected on state lands, though some facilities are projected near highly visited sites, including natural vistas.

Clearly, the heart of some of Pennsylvania's best natural habitats lies directly in the path of future energy development. Integrating information on conservation priorities into energy planning, operations, and policy by energy companies and government agencies sooner rather than later could dramatically reduce these impacts. Many factors – including energy prices, economic benefits, greenhouse gas reductions, and energy independence – will go into final decisions about where and how to proceed with energy development. Information about Pennsylvania's most important natural habitats should be an important part of the calculus about trade-offs and optimization as energy development proceeds. Would Pennsylvania's conservation pioneers, including Gifford Pinchot, Maurice Goddard, and Rachel Carson, expect anything less?

Marcellus Shale Natural Gas

Once thought to be inaccessible, deep shale formations with tightly held natural gas have become the most rapidly growing source of energy in North America. New technologies and methods have allowed companies to drill 6,000 to 10,000 feet down to reach the Marcellus shale, turn the well horizontally to follow the shale layer for a mile or more, and then pump in millions of gallons of water to fracture the shale and release the natural gas. Pennsylvania is at the epicenter of the Marcellus formation, one of the world's largest unconventional shale natural gas reserves. Situated right next door to huge markets in the Mid-Atlantic and Northeastern states, Marcellus gas development has expanded at a furious pace since the first wells were drilled just few years ago in Washington County. There are now approximately 2,000 drilled wells, most of them concentrated in the southwestern and northeastern parts of the state.

The Marcellus boom is bringing rapid economic growth to many rural communities that have been in economic decline for decades. Natural gas is also displacing higher carbon coal and oil supplies thus slowing the rise in greenhouse gas emissions. These benefits are real but not without costs. Large amounts of water must be withdrawn to frac each well (about 5 million gallons). The return flow water that comes back up from the well contains varying levels of chemicals, heavy metals, and even radioactive materials, and must be handled carefully to avoid spills when recycled or disposed. Heavy trucks and compressor stations rumble constantly in gas development areas putting heavy strains on roads, bridges and air quality. Because of known and perceived risks to environmental quality and human health, water use, air emissions and transportation demands are receiving growing attention from government agencies, researchers and energy companies. Thus far, relatively little attention, however, has been focused on Marcellus gas development impacts to natural habitats across the state.

What is Marcellus Shale Natural Gas?

The Marcellus is the largest gas-bearing shale formation in North America in both area and potential gas volume. It spans over 150,000 square miles across 5 states including the southern tier of New York, the northern and western half of Pennsylvania, the eastern third of Ohio, most of West Virginia, and a small slice of western Virginia. Estimates of the potential recoverable volume have increased steadily. The latest estimates by the U.S. Department of Energy are nearly 300 trillion cubic feet – enough to supply all natural gas demand in the United States for at least 10 years.

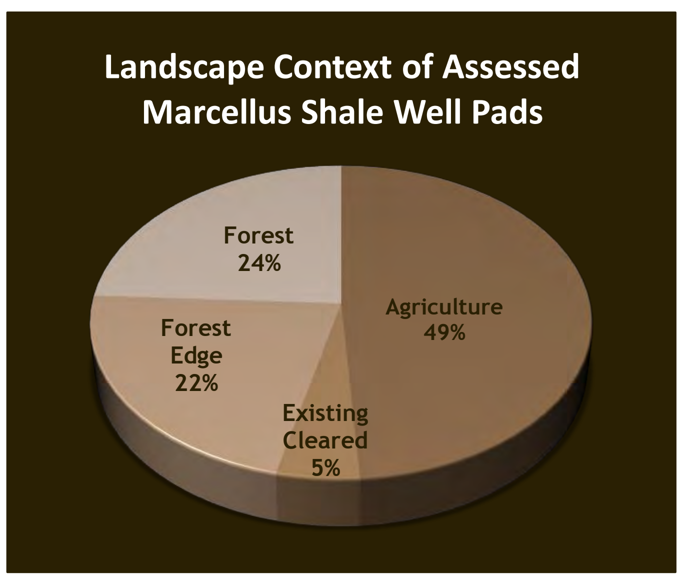
Map showing the extent of the Marcellus Shale formation. Data source: United States Geological Survey.

Geologists have long known the Marcellus formation is an organically-rich shale with potentially large amounts of natural gas, but it was too deep, too thin, and too dense to exploit. In 2005, Range Resources drilled the first production Marcellus well using horizontal drilling and hydraulic fracturing methods. The horizontal drilling is necessary because the shale is typically thin and vertical wells will only intercept a small part of the formation. Hydraulic fracturing (or "fracing") is a process that uses large volumes of water, sand, lubricants, and other chemicals to create small fissures in the shale rock. Hydro-fracing is necessary to release the gas which is tightly held in the dense black shale. These methods, first perfected for deep shale gas in the Barnett formation of Texas, unlocked the tremendous gas reserves in the Marcellus and other "unconventional" shale formations previously thought to be out of economic reach.

In contrast to shallow gas deposits in western Pennsylvania, the Marcellus is developed with multiple horizontal wells that can reach out 5,000 feet or more from one well pad. Everything about Marcellus development is bigger than conventional shallow gas plays. The well pads are more expansive (averaging just over 3 acres compared to a small fraction of an acre), the water used to frac wells is much greater (5 million gallons versus a hundred thousand gallons), and the supporting infrastructure is much larger in scale (24" diameter pipelines to gather gas from wells versus 2" or 4" pipelines in shallow fields). Individual wells are also vastly more productive (5 – 10 million cubic feet per day versus less than 100,000 cubic feet in peak early production). While the larger pad, greater water use, and more extensive infrastructure pose more challenges for conservation than shallow gas, the area "drained" by wells on each Marcellus pad is much larger than from shallow gas pads (500-1,000 acres versus 10-80 acres) since there are typically multiple lateral wells on a Marcellus pad versus a single vertical well on a shallow gas pad. The lateral reach of Marcellus wells means there is more flexibility in where pads and infrastructure can be placed relative to shallow gas. This increased flexibility in placing Marcellus infrastructure can be used to avoid or minimize impacts to natural habitats in comparison to more densely-spaced shallow gas fields.

Current and Projected Marcellus Shale Natural Gas Development

Projections of future Marcellus gas development impacts depend on robust spatial measurements of existing Marcellus well pads and infrastructure. By comparing aerial photos of Pennsylvania Department of Environmental Protection (DEP) Marcellus well permit locations taken before and after development, we precisely documented the spatial foot print of 242 Marcellus well pads (totaling 435 drilling permits) in Pennsylvania visible in 2008 aerial imagery from the National Agriculture Imagery Program. The ground excavated for wells and associated infrastructure is the most obvious spatial impact. For each well site, areas cleared for the well pad, new or expanded roads, gathering pipelines, and water impoundments were digitized and measured.



Aerial photos before and after development of a Marcellus gas well pad site in Susquehanna County, PA. To assess the impacts of this type of energy development, we digitized the spatial footprint of 242 gas well pad sites and associated infrastructure.

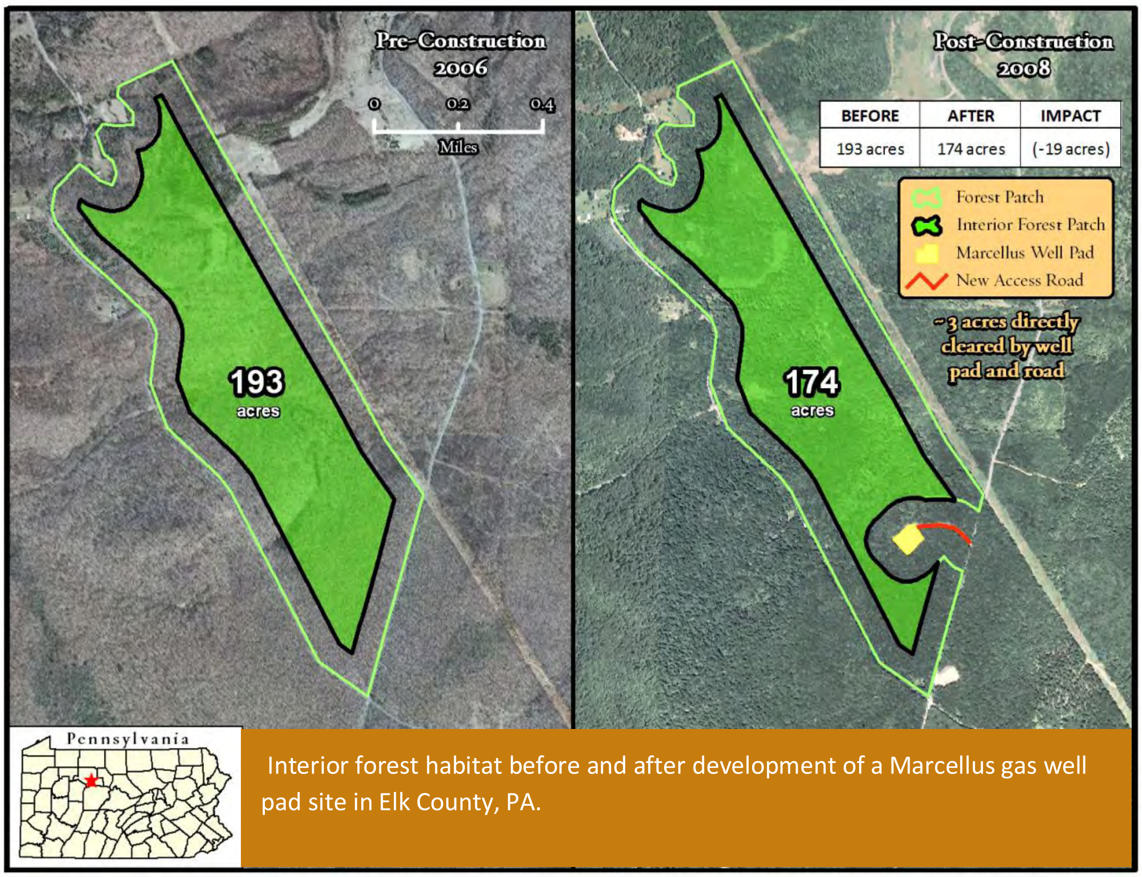
Average Spatial Disturbance for Marcellus Shale Well Pads in Forested Context (acres)		
Forest cleared for Marcellus Shale well pad	3.1	8.8
Forest cleared for associated infrastructure (roads, pipelines, water impoundments, etc.)	5.7	
Indirect forest impact from new edges	21.2	
TOTAL DIRECT AND INDIRECT IMPACTS	30	

Well pads occupy 3.1 acres on average while the associated infrastructure (roads, water impoundments, pipelines) takes up an additional 5.7 acres, or a total of nearly 9 acres per well pad.

Adjacent lands can also be impacted, even if they are not directly cleared. This is most notable in forest settings where clearings fragment contiguous forest patches, create new edges, and change habitat conditions for sensitive wildlife and plant species that depend on “interior” forest conditions.

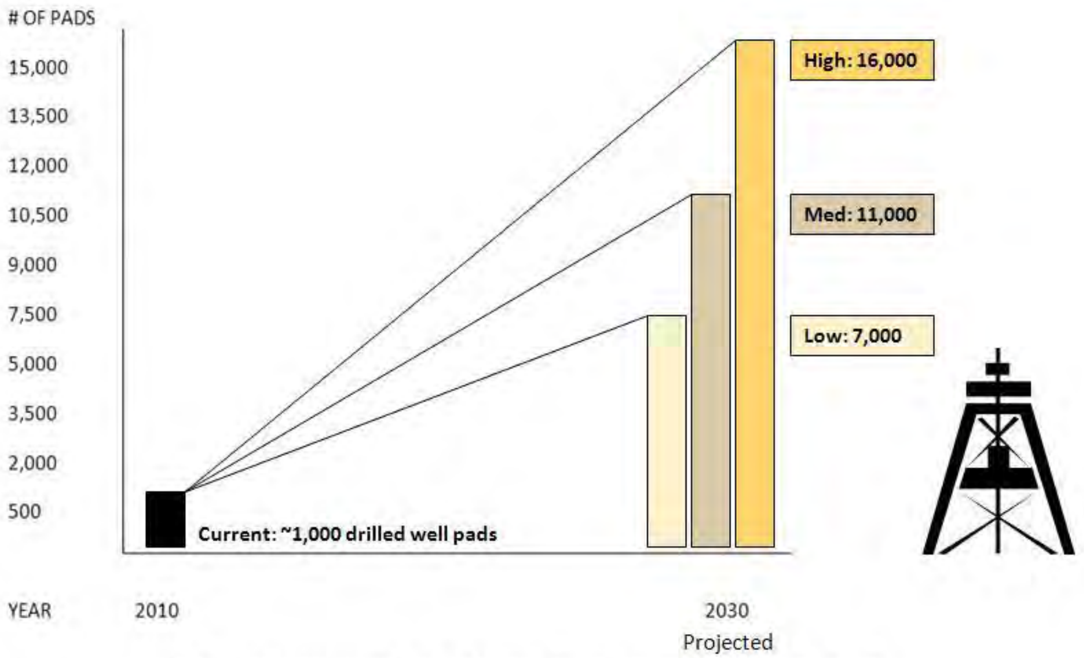
Forest ecologists call this the "edge effect." While the effect is somewhat different for each species, research has shown measurable impacts often extend at least 330 feet (100 meters) forest adjacent to an edge. Interior forest species avoid edges for different reasons. Black-throated blue warblers and other interior forest nesting birds, for example, avoid areas near edges because of the increased risk of predation. Tree frogs, flying squirrels and certain woodland flowers are sensitive to forest fragmentation because of changes in canopy cover, humidity and light levels. Some species, especially common species such as whitetail deer and cowbirds, are attracted to forest edges – often resulting in increased competition, predation, parasitism, and herbivory. Invasive plant species, such as tree of heaven, stilt grass, and Japanese barberry, often thrive on forest edges and can displace native forest species. As large forest patches become progressively cut into smaller patches, populations of forest interior species decline.

To assess the potential interior forest habitat impact, we created a 100 meter buffer into forest patches from new edges created by well pad and associated infrastructure development. For those well sites developed in forest areas or along forest edges (about half of assessed sites), an average of 21 acres of interior forest habitat was lost.



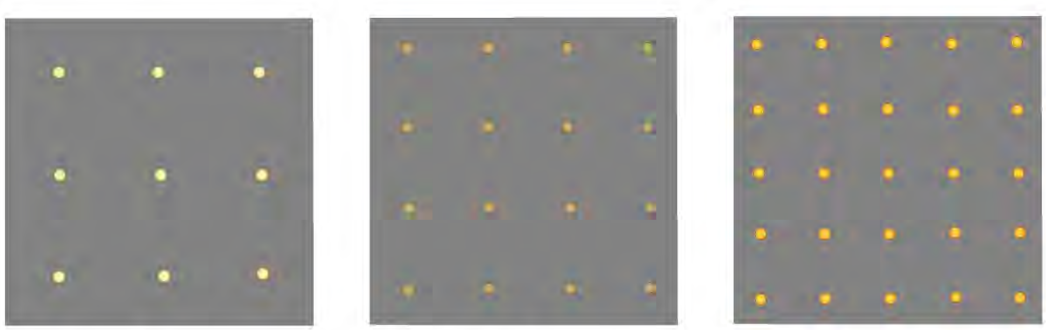
Interior forest habitat before and after development of a Marcellus gas well pad site in Elk County, PA.

The number of Marcellus wells drilled in Pennsylvania during the next two decades will expand steadily. Just how many wells are drilled will be driven by various factors including natural gas prices, technological improvements, human resources, regulatory changes in Pennsylvania and beyond (e.g., end of New York drilling moratorium), and social preferences. Assessing how these factors will change over the next two decades is very difficult; therefore our projections assume economic, policy, and social conditions remain stable enough to promote steady expansion of Marcellus gas development in the state. The first key variable in our projection is the number of drilling rigs that will be operating in Pennsylvania. By October 2010, the industry had moved just over 100 rigs into Pennsylvania to drill Marcellus wells according to the Baker-Hughes weekly rig count. Given the high productivity of the Marcellus and its proximity to major northeastern markets, most industry observers expect this number to continue growing steadily. The number of horizontal drill rigs operating in the Barnett Shale has peaked at about 200, but the



Key drivers: number of rigs, number of wells per pad.

We project 60,000 Marcellus wells will be drilled during the next twenty years based on company investor presentations and academic assessments of gas development potential. Depending on how many wells on average are placed on the same pad site (see illustration below), we project between 7,000 and 16,000 total well pad sites will be developed in Pennsylvania by 2030.



Low Scenario	Medium Scenario	High Scenario
10 wells per pad	6 wells per pad	4 wells per pad
Pads spaced ~5,200 ft apart	Pads spaced ~4,100 ft apart	Pads spaced ~3,350 ft apart

Marcellus Shale is much larger and could reach 300 rigs in Pennsylvania alone. We chose a conservative estimate of 250 maximum horizontal drill rigs for each scale projection scenario. Assuming that each rig can drill one well per month, 3,000 wells are estimated to be drilled annually. At that rate, 60,000 new wells would be drilled by the year 2030.

The second key variable, especially for determining land-use and habitat impacts, is the number of wells on each pad. Because each horizontal well can drain gas from 80 to 170 acres (depending on the lateral well length), more wells per pad translates to less disturbance and infrastructure on the landscape. It is technically possible to put a dozen or more Marcellus wells on one pad. So far, the average in Pennsylvania is two wells per pad as companies quickly move on to drill other leases to test productivity and to secure as many potentially productive leases as possible (leases typically expire after 5 years if there is no drilling activity). In many cases, the gas company will return to these pads later and drill additional wells. The low scenario (6,000 well pads) assumes that each pad on average will have ten wells. Because many leases are irregularly shaped, in mixed ownership, or the topography and geology impose constraints, it is unlikely this scenario will develop. It would take relatively consolidated leaseholds and few logistical constraints for this scenario to occur. The medium scenario for well pads assumes 6 wells on average will be drilled from each pad, or 10,000 new well pads across the state. Industry staff generally agree that six is the most likely number of wells they will be developing per pad for most of their leaseholds, at least where lease patterns facilitate drilling units of 600 acres or larger. The high scenario assumes each pad will have 4 wells drilled on average, or 15,000 well pads across the state. This scenario is more likely if there is relatively little consolidation of lease holds between companies in the next several years.

The number of well pads is less important than where they are located, at least from a habitat conservation perspective. To understand which areas within Pennsylvania's Marcellus formation are more and less likely to be developed, we used a machine-based learning modeling approach known as maximum entropy (Maxent 3.3.3a, Princeton University). Maximum entropy was used to find relationships between 1,461 existing and permitted well pad locations and variables that might be relevant to a company's decision to drill a Marcellus well. Such variables were chosen based on data availability and included Marcellus Shale depth, thickness and thermal maturity as well as percent slope, distance to pipelines, and distance to roads. The model produces a raster surface that represents the probability of an area to potentially support future gas well development. An additional 487 existing and permitted well pads were used to test the validity of the model's probability surface and the model was found to be 80% accurate in predicting existing and permitted wells from randomly sampled undeveloped areas. The resulting probability map indicates wide variation across the Marcellus formation in terms of the likelihood of future gas well development.

To get a better sense of where gas development is most likely, we searched for the highest probability areas where well pads in each scenario might be located. The probability raster was re-sampled to a resolution that reflects the minimum separation distance between well pads for each of the three impact scenarios (low – 1,590 m; medium – 1,260 m; high – 1,020 m). The minimum separation distance depends on the number of wells drilled per pad and accounts for the average gas drainage area assumed for each of the three scenarios. Areas incompatible for future gas exploration (existing drilled Marcellus Shale wells, Pennsylvania State Wild Areas and Natural Areas, and water bodies) were excluded from being selected as probable pixels. For each scenario, the highest probable pixels were selected until the pad threshold was reached (low – 6,000 well pads; medium – 10,000 well pads; high – 15,000 well pads). The highest probable pixels were then converted into points for map display purposes.

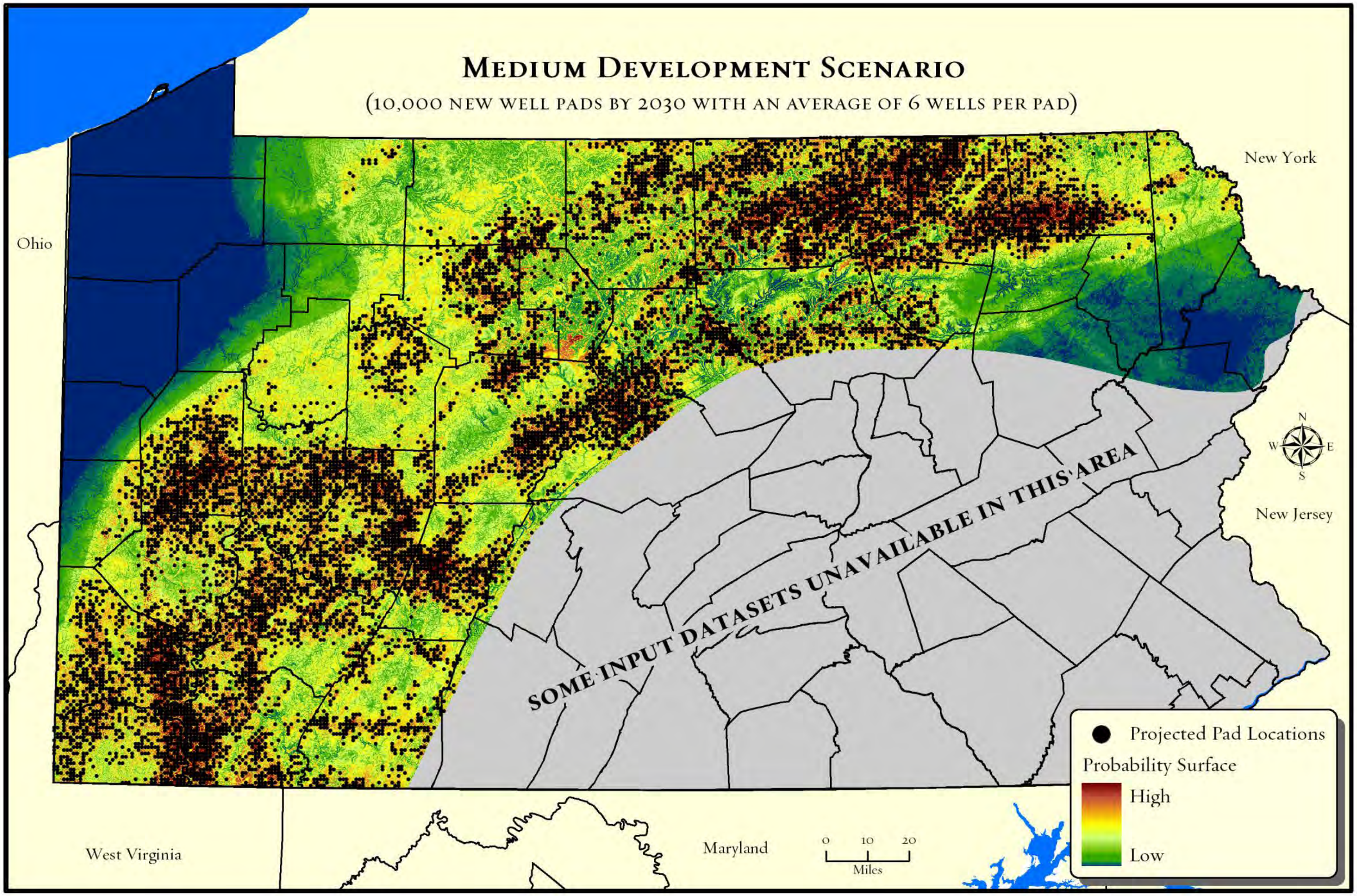
While the geographic area with projected well pads expands from low to high scenarios, the overall geographic pattern is not cumulative due to the differences in minimum separation distance between the three scenarios. Overall, hotspots for future gas development can be seen in half a dozen counties in southwestern Pennsylvania and half a dozen counties in north central and northeastern parts of the state.

These geographic projections of future Marcellus gas development are spatial representations of possible scenarios. They are not predictions. We faced several constraints in developing the geographic scenarios:

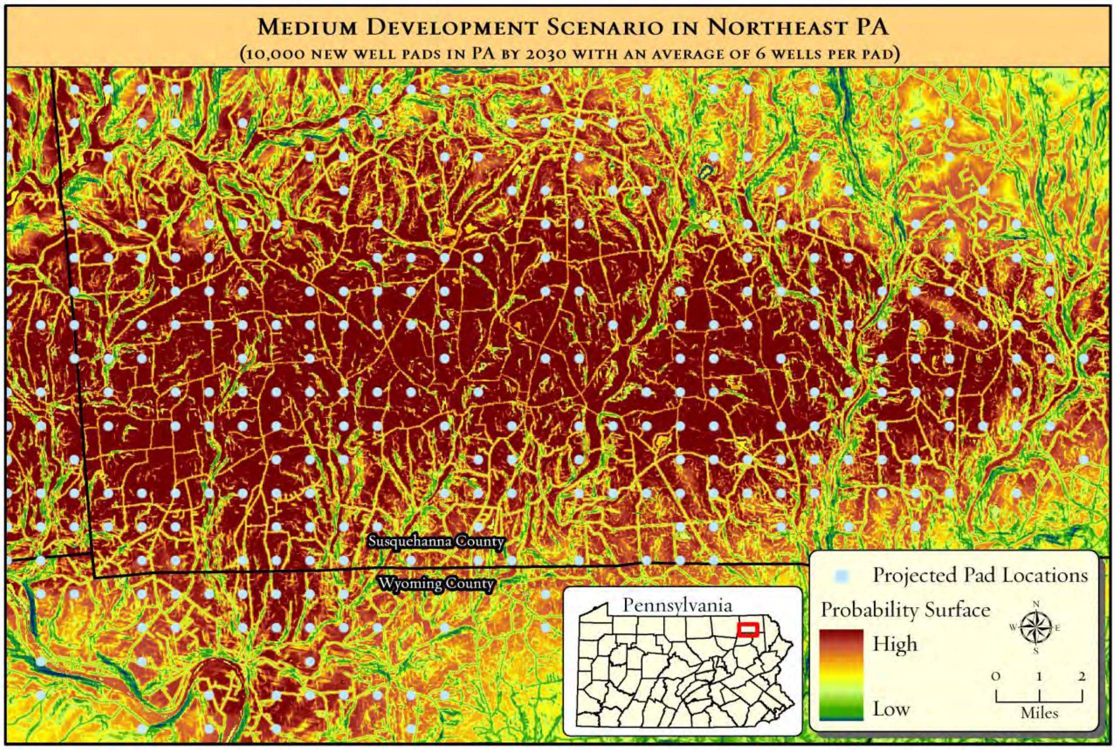
- We do not have access to proprietary seismic and test well geologic data that natural gas companies have. Shale porosity, for example, is a key factor but there are no publicly available data for this.

- We do not have the detailed location of gas company leases. Each company is looking for the highest probability locations across their lease holds while our model looks for the highest probability sites across the entire Marcellus formation in the state. Because there have only been a few Marcellus test wells and permits in the Delaware watershed, we believe the projections for new well pads are probably significantly underestimated in Wayne County.

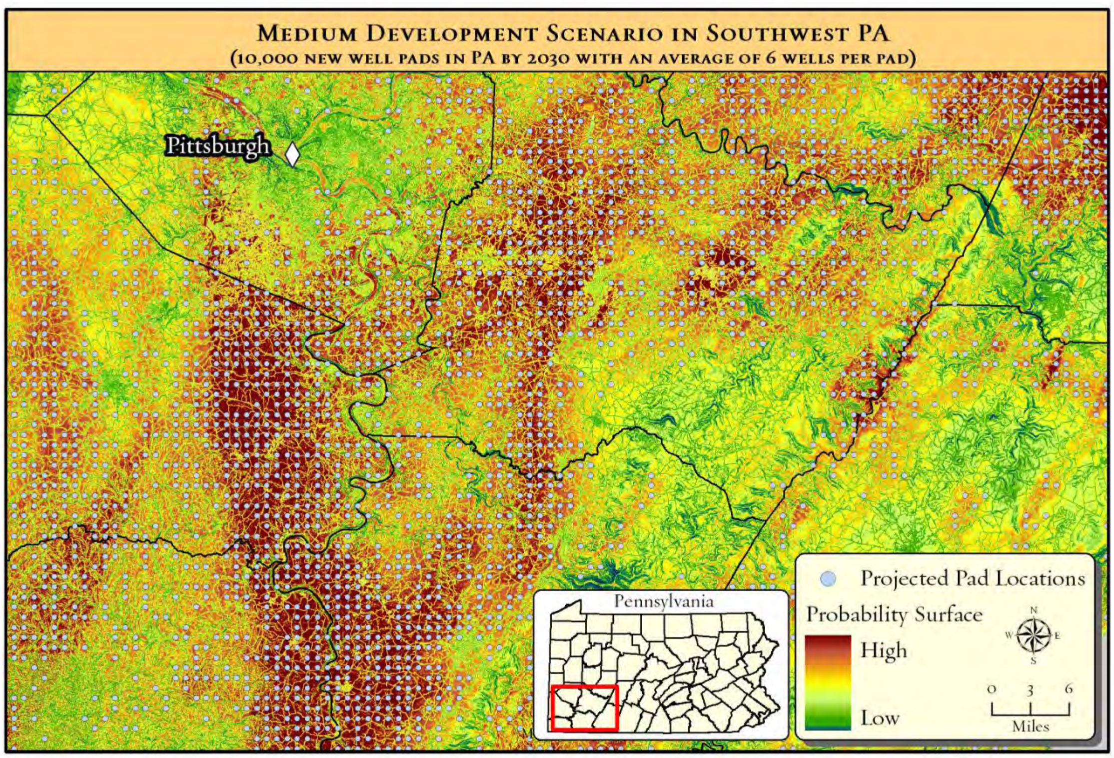
Still, we believe the overall geographic patterns in the projected gas development locations are relatively robust for several reasons. We used nearly 1,500 existing drilled or permitted well pads to build the model and nearly 500 additional drilled and permitted well pads to validate the model. These unique well pad locations represented 4,446 permitted wells. This is typically a sufficient sample size for building predictive models. Additionally, reviews from industry, academic, and government agency reviewers indicate our methods and results are generally sound. Some reviewers expect future well pad locations to be more geographically expansive than our current projections indicate, especially in the Delaware watershed where only a few Marcellus test wells and permits have been issued. Our projections for Wayne County, for example, are likely underestimating future development potential.



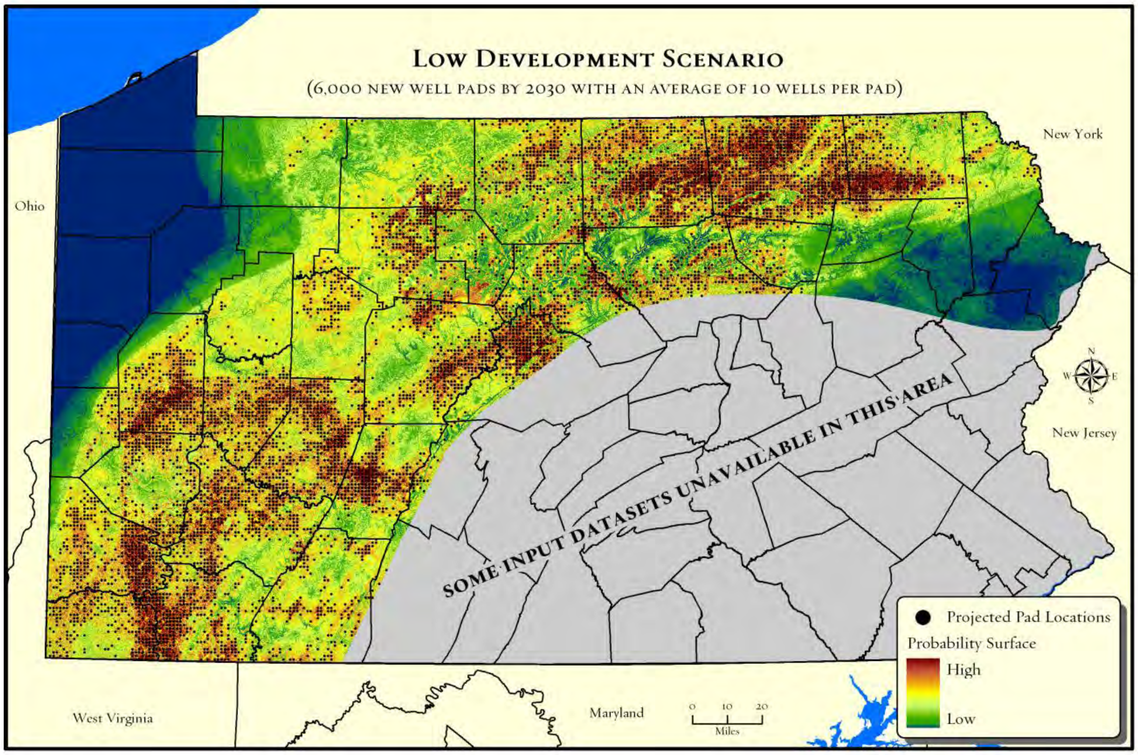
Map showing projected location of 10,000 new Marcellus Shale natural gas pads across Pennsylvania (medium development scenario).



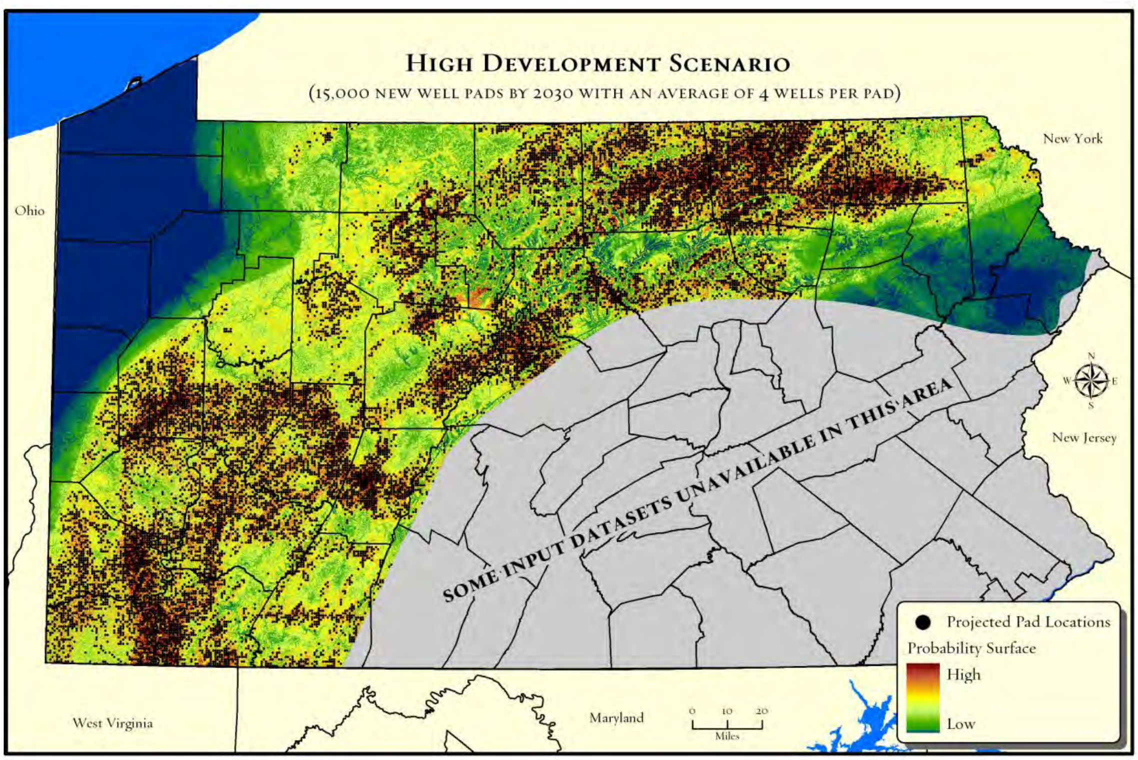
Map showing projected location of new Marcellus well pads in southern Susquehanna County under the medium development scenario.



Map showing projected location of new Marcellus well pads in southwestern Pennsylvania under the medium development scenario.



Map showing projected location of 6,000 new Marcellus well pads across Pennsylvania (low development scenario).



Map showing projected location of 15,000 new Marcellus well pads across Pennsylvania (high development scenario).

Conservation Impacts of Marcellus Shale Natural Gas Development

What is the overlap of the areas with the highest probability of future Marcellus gas development and those areas known to have high conservation values? To answer this question, we intersected the projected Marcellus well pads with areas previously identified and mapped as having high conservation values. We looked at several examples from four categories of conservation value, including:

- Forest habitats
- Freshwater habitats
- Species of conservation concern
- Outdoor recreation

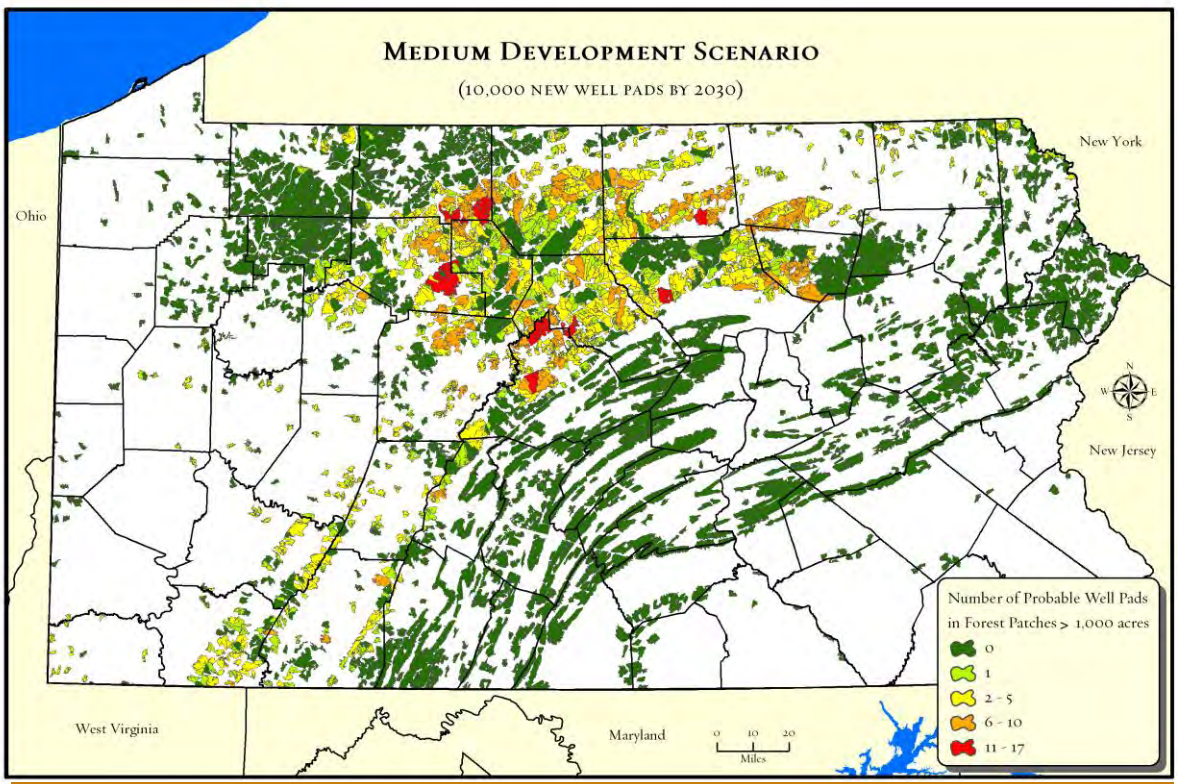
Substantial areas of overlap are indicated between likely future Marcellus development areas and Pennsylvania's most important forest, freshwater, sensitive species habitats, and outdoor recreation sites.

FORESTS

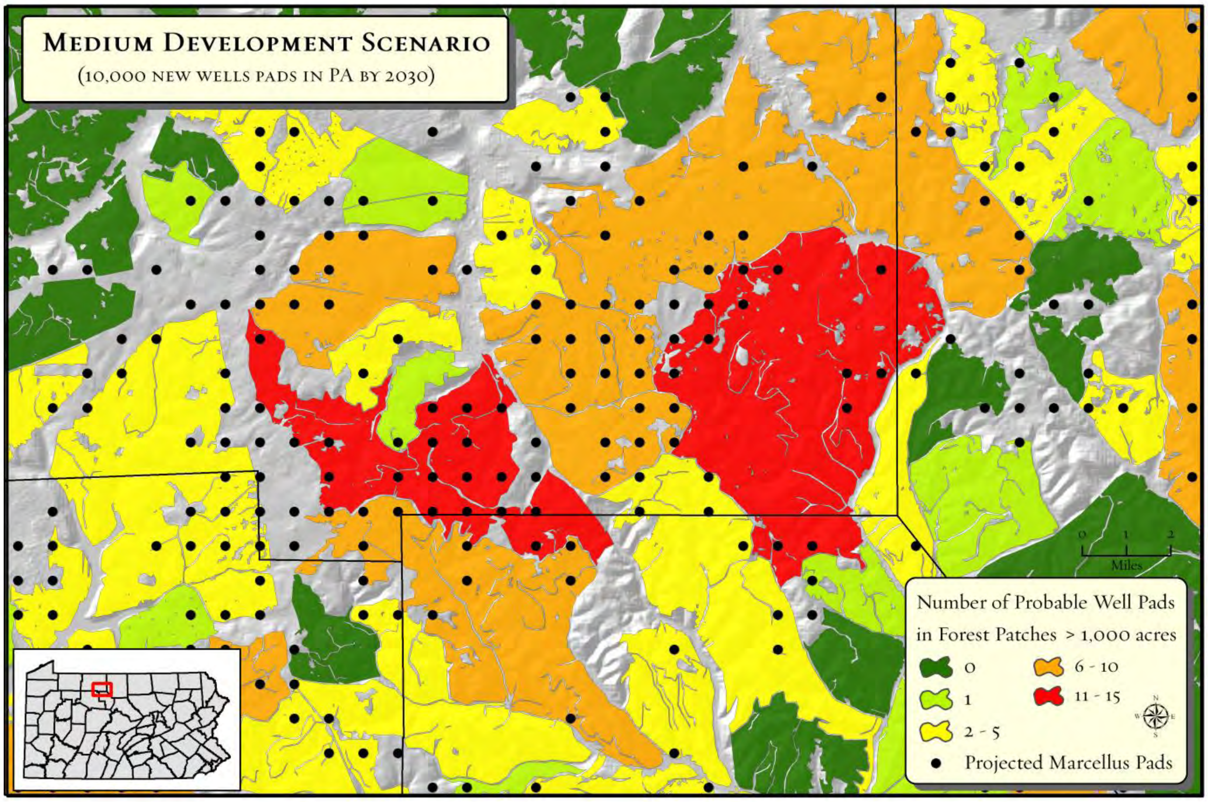
Forests are Pennsylvania's most extensive natural habitat type. Once covering at least 95 percent of the state's land area, forests were whittled away for agriculture, charcoal for iron smelting, and lumber until only a third of the state's forests remained. Forests have rebounded steadily to cover about 60 percent of the state, though a trend toward increasing net loss of forest has emerged during the past decade. Pennsylvania is famous worldwide for its outstanding cherry, oak, and maple hardwoods, and forests provide livelihoods for many thousands of Pennsylvanians in the forest products and tourism industries. They also contribute enormously to the quality of life for all Pennsylvanians by filtering contaminants from water and air, reducing the severity of floods, sequestering carbon dioxide emissions that would otherwise warm the planet, and providing a scenic backdrop to recreational pursuits.

A majority of projected well locations are found in a forest setting for all three scenarios (64% in each case). The low scenario would see 4,310 well pads in forest areas. With an average cleared forest average of 8.8 acres per pad (including roads and other infrastructure), the total forest clearing would be approximately 38,000 acres. Indirect impacts to adjacent forest interior habitats would total an additional 91,000 acres. Forest impacts from the medium scenario (6,950 projected wells in forest locations) would be 61,000 cleared forest acres and an additional 147,000 acres of adjacent forest interior habitat impacts. For the high scenario (10,250 forest well pads), approximately 90,000 acres would be cleared, and an additional 220,000 acres of forest interior habitats would be affected by new adjacent clearings. While the high Marcellus scenario would result in a loss of less than one percent of the state's total forest acreage, areas with intensive Marcellus gas development could see a loss of 2-3 percent of local forest habitats. Some part of the cleared forest area will become reforested after drilling is completed, but there has not been enough time to establish a trend since the Marcellus development started.

Large contiguous forest patches are especially valuable because they sustain wide-ranging forest species, such as northern goshawk, and provide more habitat for forest interior species. They are also more resistant to the spread of invasive species, suffer less tree damage from wind and ice storms, and provide more ecosystem services – from carbon storage to water filtration – than small patches. The Nature Conservancy and the Western Pennsylvania Conservancy's Forest Conservation Analysis mapped nearly 25,000 forest patches in the state greater than 100 acres. Patches at least 1,000 acres in size are about a tenth of the total (2,700) and patches at least 5,000 acres are rare (only 316 patches). In contrast to overall forest loss, projected Marcellus gas development scenarios indicate a more pronounced impact on large forest patches. For example, 40 percent of patches greater than 5,000 acres are projected to have at least one well pad and associated infrastructure located in them in the medium scenario compared to just over 20 percent for patches > 1,000 acres. Most affected large patches have multiple projected well pads (as many as 29). The projections indicate larger patches are likely to be more vulnerable, with over a third projected to have at least one new well pad and road. Many affected large patches have multiple projected well pads (as many as 17 for patches). While one or two well pads and associated infrastructure may not fragment the large patch into smaller patches, each additional well pad increases the likelihood that the large patch will become several smaller patches with a substantially reduced forest interior habitat area.



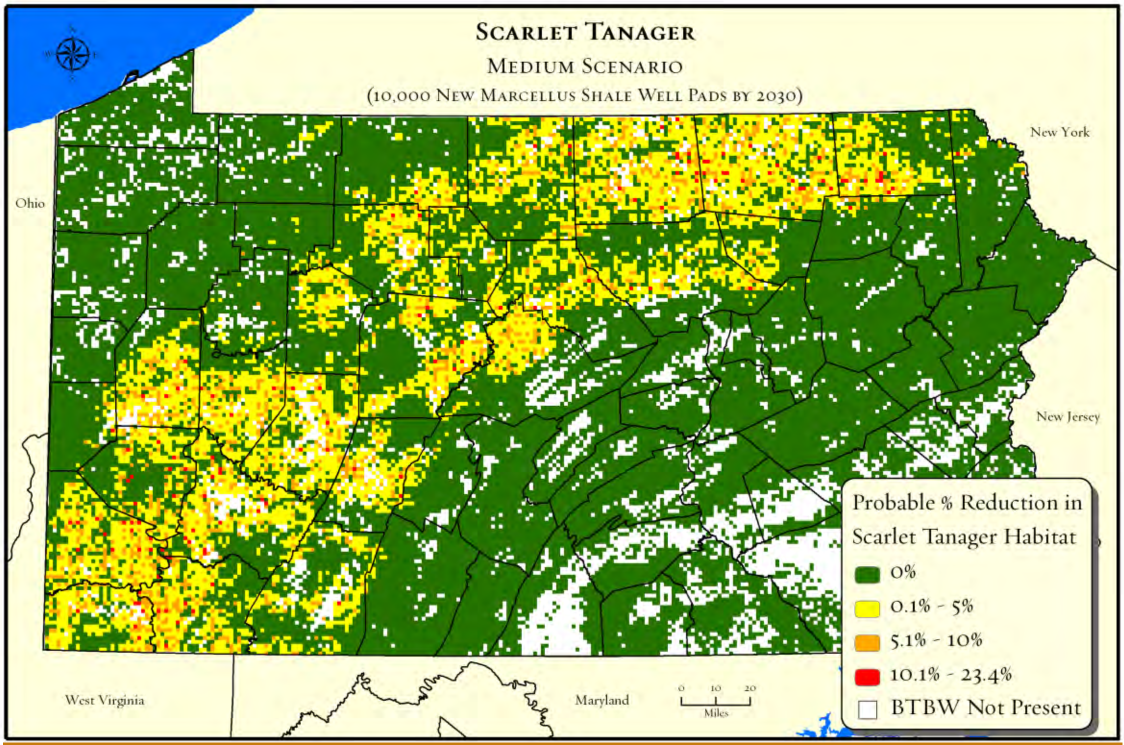
Map showing number of probable Marcellus well pads in forest patches greater than 1,000 acres across Pennsylvania.



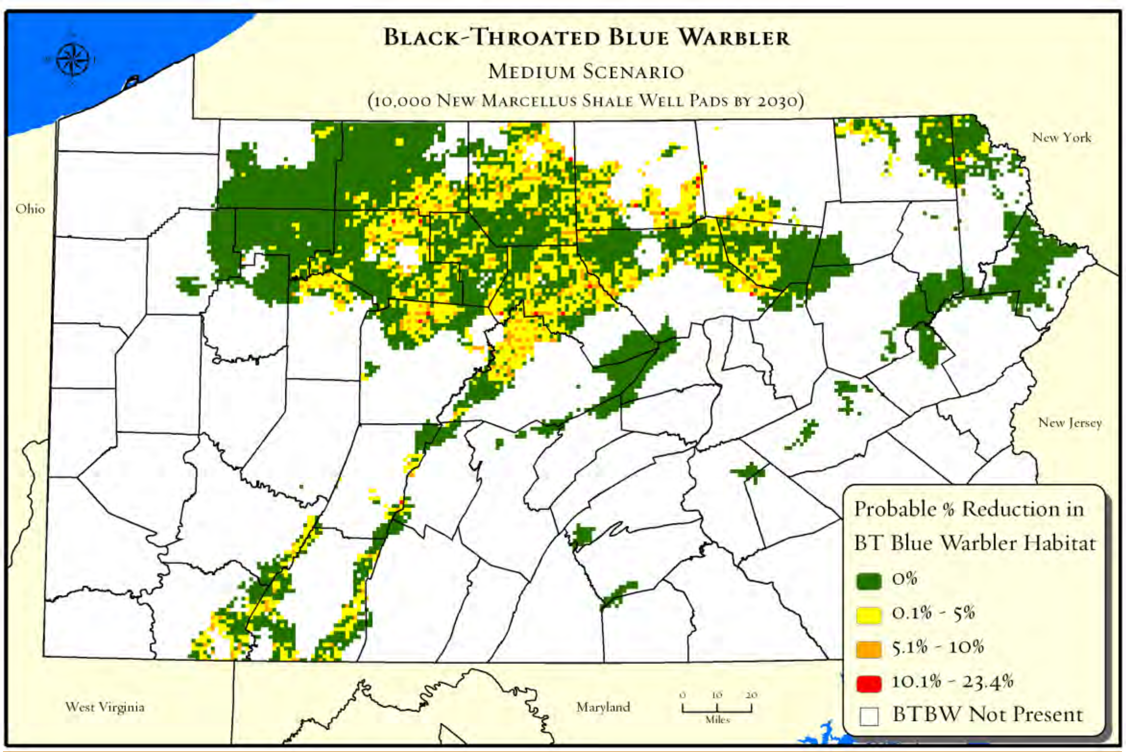
Map showing projected number of well pads in forest patches greater than 1,000 acres under the medium development scenario in Potter, Cameron, McKean and Forest Counties.

Bird species that nest in close canopy forest environments are often referred to as "forest interior" species. The Carnegie Museum of Natural History, Powdermill Nature Reserve and the Pennsylvania Game Commission recently completed Pennsylvania's Second Breeding Bird Atlas project. As part of the project, trained ornithologists conducted point counts using standardized protocols at 39,000 sites from 2004 to 2009. The result is an incredibly detailed data base that provides the most accurate information on the distribution and density of breeding birds available anywhere in the United States. Density data for several forest interior nesting species were mapped and intersected with the projected Marcellus gas well pad locations. The resulting maps show the estimated reduction in habitat for that species in each Marcellus gas probability pixel (including both cleared forest and adjacent edge effects). Scarlet Tanagers are one of the most widespread forest interior nesting bird in the state. Since they are so widespread, a majority of their range in the state is outside of the most likely Marcellus development areas. In some locations, scarlet tanager populations could decline by as much as 23 percent in the Medium Scenario. Black-throated blue warblers are more narrowly distributed in Pennsylvania favoring mature northern hardwood and coniferous forests with a dense understory, frequently in mountain terrain. Since most of their breeding range in Pennsylvania overlaps with likely Marcellus development areas, a higher proportion of their habitat could be affected.

Scarlet tanager © U.S. Fish and Wildlife Service



Map showing estimated percent loss of habitat for Scarlet Tanagers under medium scenario.

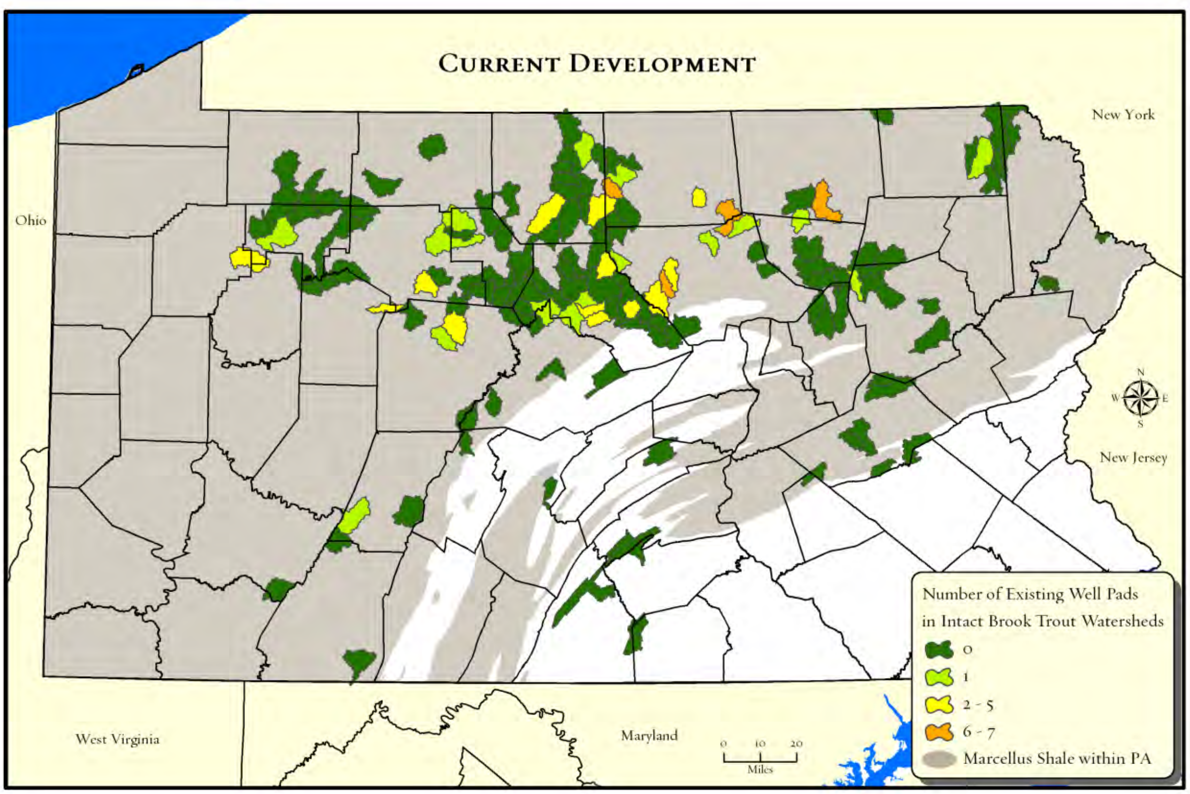


Map showing estimated percent loss of habitat for Black-Throated Blue Warblers under medium scenario.

FRESHWATER

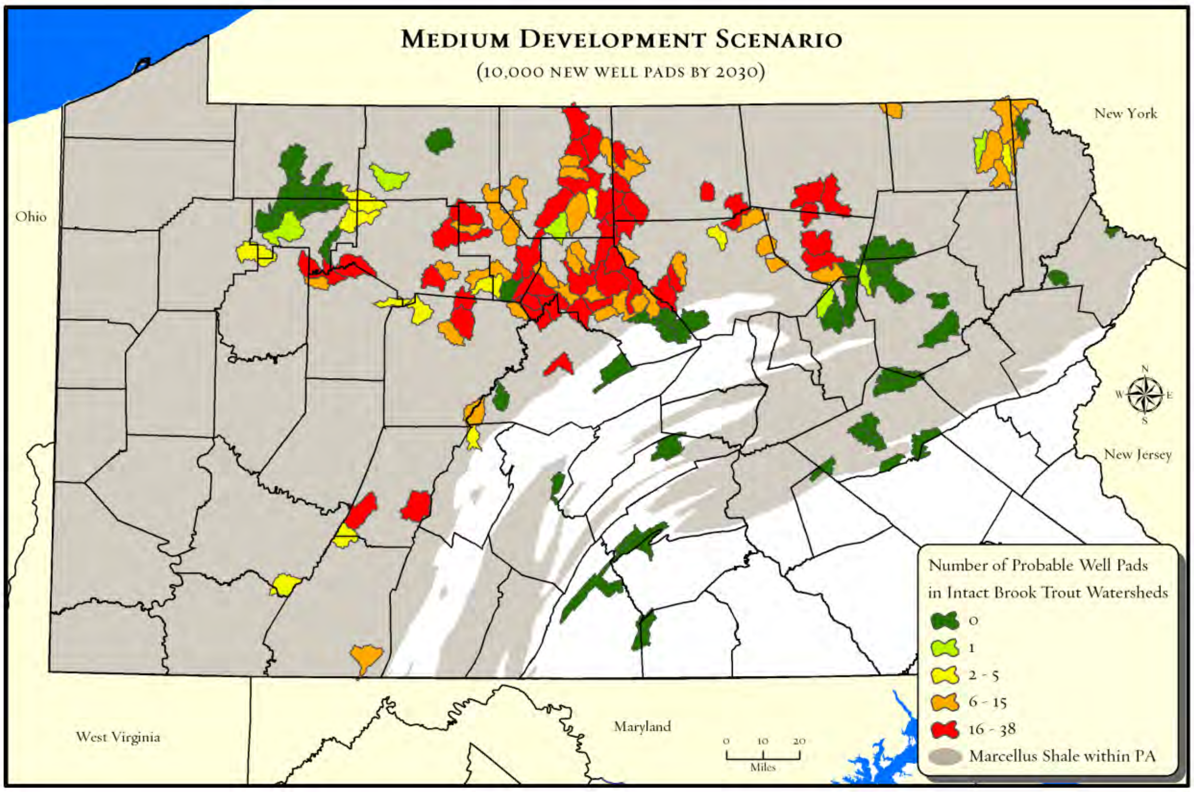
Home to three great river systems and one of the Great Lakes, Pennsylvania's fresh water resources are vital not only to the Commonwealth but to much of the eastern United States. The ***Ohio River*** basin contains the richest fresh water ecosystems in North America. In Pennsylvania, French Creek and parts of the Upper Allegheny River contain some of the most intact aquatic ecosystems in the entire basin. The ***Susquehanna* River** is the source of more than half the fresh water that enters the Chesapeake Bay, and most of the water that flows down the Susquehanna River originates in tributary headwaters across a wide swath of central Pennsylvania. Forming Pennsylvania's eastern boundary, the ***Delaware River*** is the longest undammed river in the eastern United States, one of the last strongholds for Atlantic coast migratory fish, and provides the drinking water source for nearly 20 million Americans living in Pennsylvania, New York, and New Jersey. Because of their importance to human health and livelihoods, the potential of Marcellus gas development to affect water flows and quality have received growing attention from regulatory agencies, natural gas companies, and environmental groups.

The intersection of gas development with sensitive watersheds has received less attention. High Quality and Exceptional Value (EV) watersheds have been designated by the Pennsylvania Department of Environmental



Map showing current number of Marcellus well pads in intact and predicted intact brook trout watersheds. Data source: Eastern Brook Trout Joint Venture.

Protection across the state. Our projections indicate 28 percent of High Quality and 5 percent of Exceptional Values streams have or will have Marcellus gas development during the next two decades. Presence of well pads in these watersheds may not be a problem as long as spill containment measures and erosion and sedimentation regulations are strictly observed and enforced in these areas. More specifically, the projections indicate 3,581 well pads could be located within ½ mile of a High Quality or Exceptional Values streams. Pads within close proximity to High Quality and especially Exceptional Value streams pose more risk than those at greater distances, as there is increased risk for potential spills and uncontained sediments to find their way into streams.



Map showing projected number of Marcellus well pads by 2030 in intact and predicted intact brook trout watersheds under medium scenario. Data source: Eastern Brook Trout Joint Venture.

Native brook trout are one of the most sensitive aquatic species in Pennsylvania watersheds. Brook trout favor cold, highly-oxygenated water and are unusually sensitive to warmer temperatures, sediments, and contaminants. Once widely distributed across Pennsylvania, healthy populations have retreated to a shrinking number of small watersheds. Many of these watersheds overlap with the Marcellus shale formation. A large majority (113) of the 138 intact or predicted intact native brook trout watersheds in Pennsylvania are projected to see at least some Marcellus gas development. Over half (74) are projected to host between 6 – 38 well pads, and the number reaches as high as 64 pads for some intact brook trout watersheds in the high scenario. Rigorous sediment controls and carefully designed stream crossings will be critical for brook trout survival in watersheds, especially upper watersheds, with intensive Marcellus development.

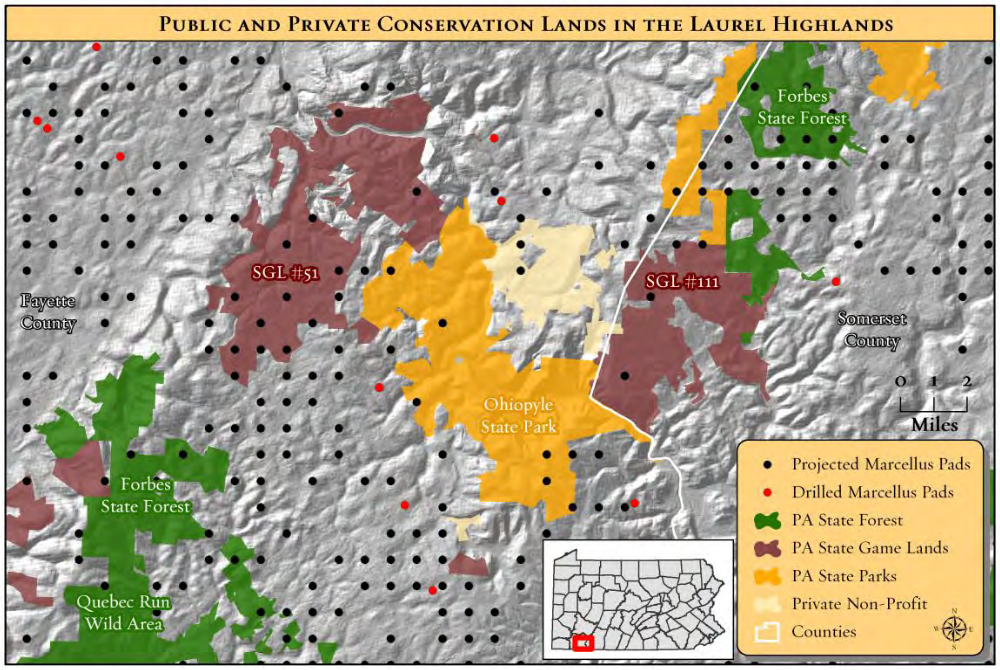
RARE SPECIES


Green salamander © Pennsylvania Fish and Boat Commission

Of the approximately 100,000 species believed to occur in Pennsylvania, just over 1 percent (1052) is tracked by The Pennsylvania Natural Heritage Program (PNHP). Due to low population sizes and immediate threats, these species are rare, declining or otherwise considered to be of conservation concern. PNHP records indicate that 329 tracked species have populations within pixels that have a relatively high modeled probability for Marcellus development. Nearly 40 percent (132) are considered to be globally rare or critically endangered or imperiled in Pennsylvania. Many are found in riparian areas, streams, and wetlands, while others are clustered in unusually biologically diverse areas such as the Youghiogheny Gorge. Some of these species may have only one, two or three populations left in the state. Two examples include the green salamander (*Aniedes aeneus)* with all known populations in relatively high probability Marcellus development pixels and snow trillium (*Trillium nivale*) with 73 percent of known populations in relatively high probability pixels. A well-managed screening system to identify the presence of these species and their preferred habitats will be critical to their survival as energy development expands across the state.

RECREATION

Pennsylvania has built one of the largest networks of public recreation lands in the eastern United States, but much of it could see Marcellus and other natural gas development in coming decades. Of the 4.5 million acres of state and federal lands in the state, we estimate as little as 500,000 acres are permanently protected from surface mineral development, including gas drilling. State and federal agencies do not own mineral rights under at least 2.2 million acres. Most other areas where the state does own mineral rights can be leased, such as the estimated 700,000 acres previously leased for gas development on state forest lands. Severe budget pressures will likely to tempt the legislature to lease additional lands in the future. Our projections excluded state Wild and Natural Areas, National Park lands, and Congressionally-designated Wilderness Areas but otherwise assumed that high probability Marcellus gas pixels on public lands could be developed. The low scenario projects 897 pad locations on State Forest and State Game Lands which expands to 1,438 well pads in the medium scenario and 2,096 pads in the high scenario. The focal area below illustrates what the overlap of future gas development and conservation lands could look like in the medium scenario for the southern Laurel Highlands. It projects 7 well pads in the portion of Forbes State Forest visible in the focal area above, 13 pads on State Game Lands 51, and 3 on State Game Lands 111.



Map showing projected Marcellus well pads under the medium scenario on public and private conservation lands in the Laurel Highlands.

Pennsylvania's state park system, recognized as one of the best in the nation, illustrates the challenge of protecting recreational values in areas of intensive Marcellus development. While the DCNR has a long standing policy of not extracting natural resources in state parks, it does not own the mineral rights under an estimated 80 percent of the system's 283,000 acres. Our projections indicate Marcellus well pads could be located in between 9 and 22 state parks.

AVOIDING FOREST IMPACTS IN THE LAUREL HIGHLANDS

The projected potential impacts of Marcellus gas energy development assume recent patterns of development will continue. Given the relatively large areas drained by Marcellus gas pads (depending on the lateral length and number of wells per pad), there is flexibility in how they are placed. This allows us potentially to optimize between energy production and conservation outcomes. To look at how conservation impacts could be minimized, we examined how projected Marcellus gas pads could be relocated to

Projected Well Pads on State Lands (Medium Scenario)	
DCNR State Forests	**1,002**
DCNR State Parks	**41**
State Game Lands	**436**
Total State Lands	**1,479**

avoid forest patches in the Southern Laurel Highlands in Fayette and Somerset counties. This area is important because it represents a unique ecological region with a large amount of state land as well as private farmland and forest land. The area is also facing great pressure to develop the Marcellus Gas resource. The focus area included approximately 350 square miles and included Chestnut Ridge on its western border and Laurel Ridge on its east. Within the area, there are two state parks (Ohiopyle State Park and Laurel Hill State Park), two State Game Lands (SGL 51, SGL 111), and state forest land (Forbes State Forest).

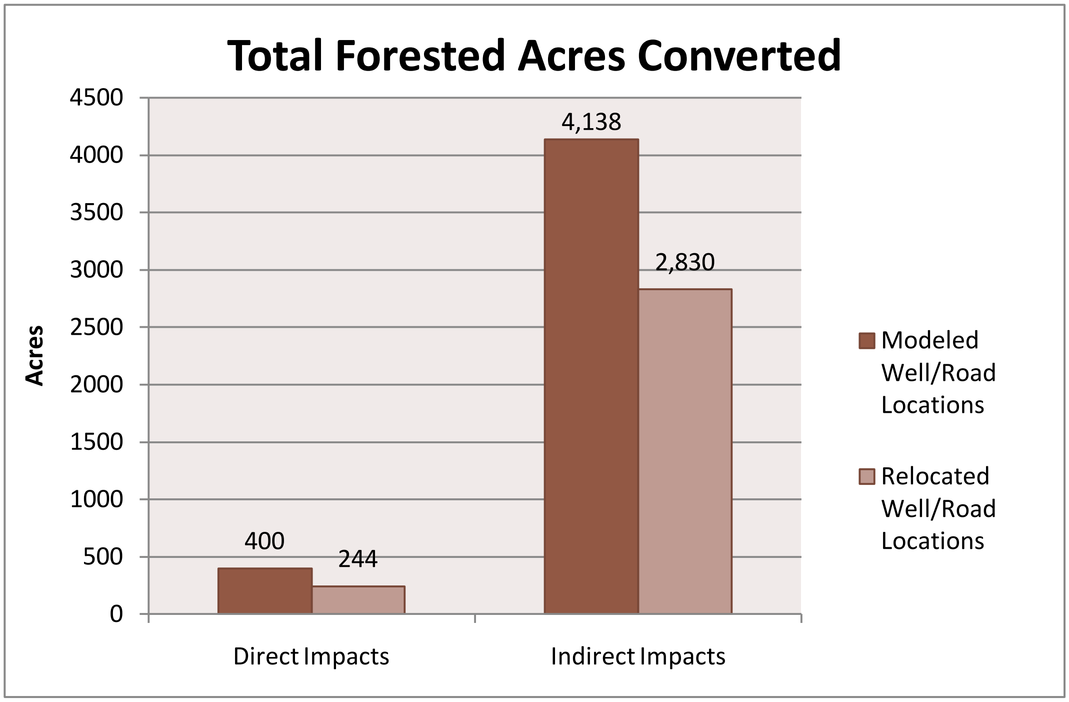
The Medium Scenario projected 127 well pads in the focus area. Fourteen well pads were projected in agricultural fields, 33 were in edge habitat (within 100 m of the forest edge), 11 fell within existing cleared areas (e.g. strip mines), and 69 were in forest. There were five pads on Ohiopyle State Park, and 13 within a mile of its boundary. Laurel Ridge State Park contained two pads. Forbes State Forest had seven modeled pads. State Game Lands 111 had 3 pads, and SGL 51 had 13. It was not clear if DCNR State Parks Bureau or the Game Commission control the sub-surface mineral rights beneath the 23 modeled pads. Given that 80 percent of mineral rights are severed on State Park and State Game Lands (and close to 100 percent in western parts of the state), we have assumed that drilling could happen at those projected locations.

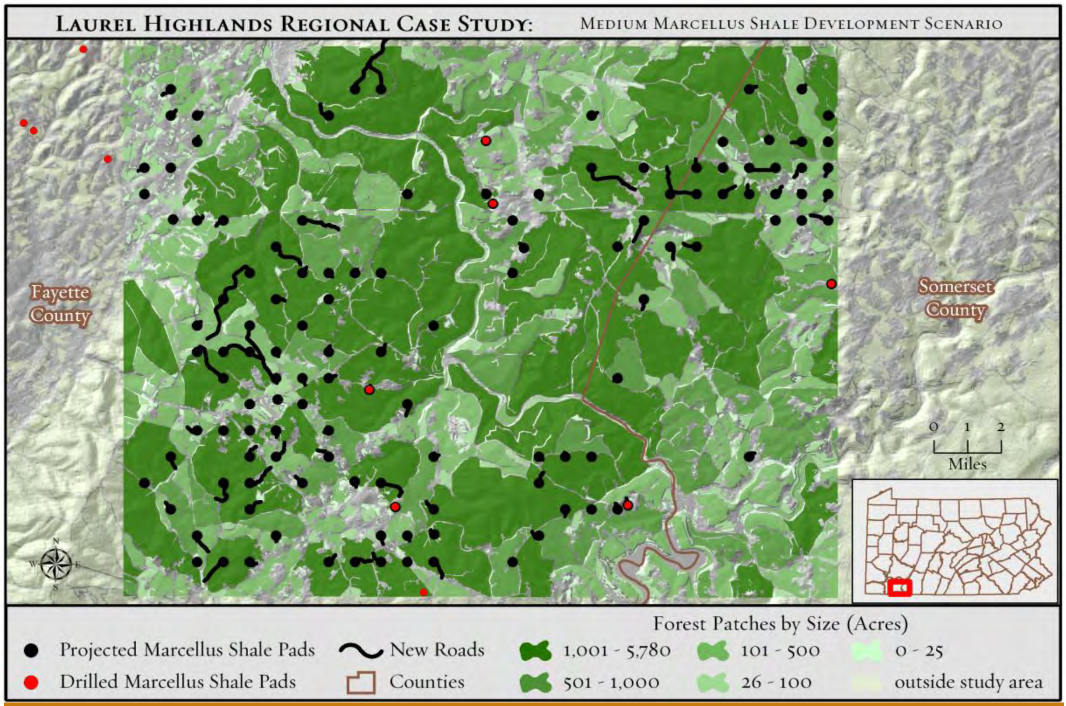
To assess additional impacts beyond the well pad itself, we placed a new and/or improved road from the projected pad to the nearest existing road (ESRI Roads Layer). We placed new roads along existing trails, paths and openings whenever detectable on aerial photo imagery (used Bing Maps and 2005-2006 PA Map imagery), avoiding wetlands, steep slopes, cliffs, rock outcrops, and buildings, and where possible, rivers, streams, and forest patches. The projected pads and roads required clearing 400 acres of forest.

Can a modest shift in the location of well pads reduce impacts to forest patches and conservation lands? To reduce the impacts to forest habitats, the wells were relocated to nearby existing anthropogenic openings, old fields, or agricultural fields. Attempts were made to maintain the 4,200 foot (1,260 m) distance between modeled wells. If nearby open areas did not exist, the locations of the well pads were moved toward the edges of forest patches to minimize impacts to forest interior habitats. A set of rules was developed and followed to minimize bias, including:

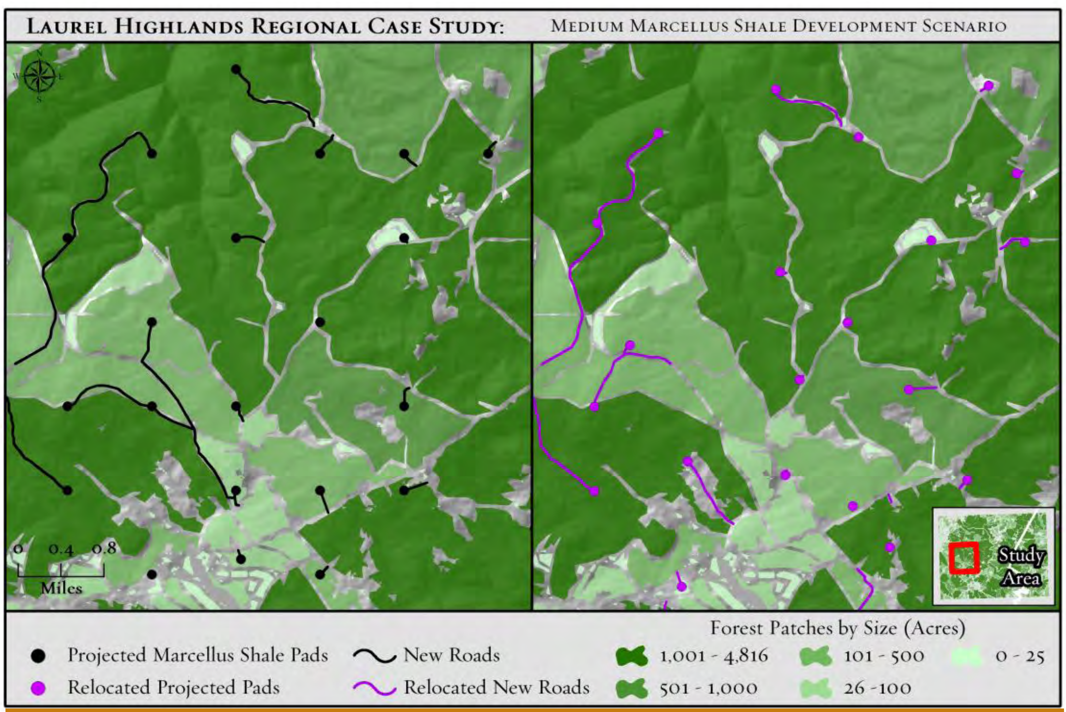
1. Modeled well pads were not relocated if they occurred in old fields or agricultural fields.
2. Modeled well pads that occurred in forest or edge habitat were moved but well pads were placed in the same general areas as the modeled well pad;
3. Attempts were made to avoid placing relocated well pads any closer that the minimum distance between pads, as specified by the medium scenario (1260 m)
4. Agriculture, cleared land (e.g., former strip mines), or otherwise opened land cover was favored over forest or edges for relocating well pads;
5. If the well pad could not be placed in an open area, forest edges were favored over deep interior forest;
6. Residential areas were avoided. Relocated well pads were placed at least 500 feet (150 m) from homes;
7. Wetlands, water, steep slopes, cliffs, rock outcrops, creeks and rivers, buildings and manicured lawns were avoided;
8. Relocated well pads were only placed in areas with similar to those that supported modeled pads.
9. Relocated well pads often were connected to roads using existing trails, paths and openings whenever detectable on aerial photo imagery (used Bing Maps and 2005-2006 PA Map imagery);
10. The same number of relocated well pads were placed on state lands and Western Pennsylvania Conservancy lands as they were in the modeled output;
11. When the modeled well pad occurred within a forest patch with no nearby alternative locations (due to proximity of other wells or environmental constraints), the projected well pad was not relocated.

The relocated wells and roads did not eliminate forest impacts in this heavily forested landscape, but there was a significant reduction. Total forest loss declined almost 40% while impacts to interior forest habitats adjacent to new clearings declined by a third.





Location of 127 projected Marcellus well pads and new roads in the study area in the southern Laurel Highlands.



Relocated well pads (on the right) reduced forest clearing and forest interior habitat impacts by 40 % and 33% respectively compared to the projected well pads (on the left).

Key Findings

Key findings from the Pennsylvania Energy Impacts Assessment for Marcellus Shale natural gas include:

- About 60,000 new Marcellus wells are projected by 2030 in Pennsylvania with a range of 6,000 to 15,000 well pads, depending on the number of wells per pad;

- Wells are likely to be developed in at least 30 counties, with the greatest number concentrated in 15 southwestern, north central, and northeastern counties;

- Nearly two thirds of well pads are projected to be in forest areas, with forest clearing projected to range between 38,000 and 90,000 acres depending on the number of number of well pads that are developed. An additional range of 91,000 to 220,000 acres of forest interior habitat impacts are projected due to new forest edges created by well pads and associated infrastructure (roads, water impoundments);

- On a statewide basis, the projected forest clearing from well pad development would affect less than one percent of the state's forests, but forest clearing and fragmentation could be much more pronounced in areas with intensive Marcellus development;

- Approximately one third of Pennsylvania's largest forest patches (>5,000 acres) are projected to have a range of between 1 and 17 well pads in the medium scenario;

- Impacts on forest interior breeding bird habitats vary with the range and population densities of the species. The widely-distributed scarlet tanager would see relatively modest impacts to its statewide population while black-throated blue warblers, with a Pennsylvania range that largely overlaps with Marcellus development area, could see more significant population impacts;

- Watersheds with healthy eastern brook trout populations substantially overlap with projected Marcellus development sites. The state's watersheds ranked as "intact" by the Eastern Brook Trout Joint Venture are concentrated in north central Pennsylvania, where most of these small watersheds are projected to have between two and three dozen well pads;

- Nearly a third of the species tracked by the Pennsylvania Natural Heritage Program are found in areas projected to have a high probability of Marcellus well development, with 132 considered to be globally rare or critically endangered or imperiled in Pennsylvania. Several of these species have all or most of their known populations in Pennsylvania in high probability Marcellus gas development areas.

- Marcellus gas development is projected to be extensive across Pennsylvania's 4.5 million acres of public lands, including State Parks, State Forests, and State Game Lands. Just over 10 percent of these lands are legally protected from surface development.

- Integration of conservation features into the planning and development of Marcellus gas well fields can significantly reduce impacts. For example, relocating projected wells to open areas or toward the edge of large forest patches in high probability gas development pixels in the southern Laurel Highlands reduces forest clearing by 40 percent and forest interior impacts by over a third.

Additional Information

- Geologic information on the Marcellus shale formation in Pennsylvania: http://www.dcnr.state.pa.us/topogeo/oilandgas/marcellus_shale.aspx

- Estimates of Marcellus shale formation gas reserves: http://geology.com/articles/marcellus-shale.shtml

- Baker-Hughes weekly oil and gas rig count http://gis.bakerhughesdirect.com/Reports/StandardReport.aspx

- Pennsylvania Department of Environmental Protection, Permit and Rig Activity Report: http://www.dep.state.pa.us/dep/deputate/minres/oilgas/RIG10.htm

- Copeland, H. E., K.E. Doherty, D.E. Naugle, A. Pocewicz, and J. M. Kiesecker. 2009. Mapping Oil and Gas Development Potential in the US Intermountain West and Estimating Impacts to Species: http://www.plosone.org/article/info%3Adoi%2F10.1371%2Fjournal.pone.0007400

- Overview of forest fragmentation impacts on forest interior nesting species: http://www.state.nj.us/dep/fgw/neomigr.htm

- Overview of Pennsylvania High Quality and Exceptional Value Streams: http://www.dcnr.state.pa.us/wlhabitat/aquatic/streamdist.aspx

- Pennsylvania Department of Environmental Protection, Chapter 93 Water Quality Standards, Exceptional Value and High Quality Streams: data downloaded from Pennsylvania Spatial Data Access: http://www.pasda.psu.edu

- Eastern Brook Trout Joint Venture intact brook trout watersheds: http://128.118.47.58/EBTJV/ebtjv2.html

- Overview of Carnegie Museum of Natural History, Powdermill Nature Reserve, and the Pennsylvania Game Commission's 2nd Pennsylvania Breeding Bird Atlas Project: http://www.carnegiemnh.org/powdermill/atlas/2pbba.html

- Pennsylvania Natural Heritage Program, including lists of globally rare and state endangered and imperiled species: http://www.naturalheritage.state.pa.us/

- U.S. Department of Agriculture, Natural Resources Conservation Service, National Agriculture Imagery Program: http://datagateway.nrcs.usda.gov/GDGOrder.aspx

- DigitalGlobe, GlobeXplorer, ImageConnect Version 3.1: http://www.digitalglobe.com

Wind

Wind has become one of the country's fastest growing sources of renewable energy. Pennsylvania is a leader in the industry as host to several wind company manufacturing plants and corporate headquarters. Wind energy development has been spurred by its potential to reduce carbon emissions, promote new manufacturing jobs, and increase energy independence. Technological advances have expanded the size and efficiency of wind turbines during the past decade. This, together with state and federal incentive programs, has facilitated wind development in Pennsylvania, which otherwise ranks relatively low among states for its potential wind generation capacity. The eight turbines installed next to the Pennsylvania Turnpike in Somerset County a decade ago have grown to nearly 500 turbines, with more permitted for construction (AWEA, 2010). Topography is a key factor in average wind speeds across Pennsylvania, so nearly all turbines have been built on mountain ridgelines or on top of high elevation plateaus.

Wind energy has become the most symbolic icon of the shift toward a low carbon economy. With no air emissions or water consumption, it is one of the cleanest renewable energy types. Communities across the state benefit economically as rural landowners lease their properties, skilled jobs are created to manufacture turbines, and workers are hired to install and maintain turbines. Wind development has faced controversy in some areas from neighboring landowners and those worried about impacts to migrating birds and bats. The wind industry, government agencies, and independent researchers have invested considerable effort in trying to better understand impacts on birds and bats. For example, 26 wind development companies have signed a cooperative agreement with the Pennsylvania Game Commission to conduct bird, bat and animal surveys using specified protocols in proposed development areas. Among other findings have been the discovery of the Pennsylvania's second largest Indiana bat maternal colony and a variety of previously undocumented foraging and roosting locations for the state's two rarest bats (Indiana and eastern small-footed). Less understood are the potential habitat impacts of wind development in the northeastern United States. This assessment, therefore, focuses on impacts to forest and stream habitats and selected species of conservation concern that may be vulnerable to development of ridgetop habitats.

What is Wind Energy?

Wind mills have powered grain processing and water pumping in agriculture around the world – most famously in the Netherlands – for centuries. The first modern wind facilities to generate electricity were built in California in the early 1980s. Rated at less than 0.5 MW capacity per turbine, the towers were only 50 feet tall. These facilities were poorly designed and generated considerable controversy because they caused significant mortalities to migrating hawks and eagles. Wind energy development did not expand appreciably until the late 1990s when newer turbine designs and federal energy incentives stimulated the development of new facilities. These turbines were rated at 1.0 or 1.5 MW capacity and reached about 200 feet high at the tip of their rotor. Since the power produced by a wind turbine is proportional to the cube of the blade size and how high in the air it is; turbine size, height and power ratings have expanded steadily. The largest turbines installed in Pennsylvania are now rated at

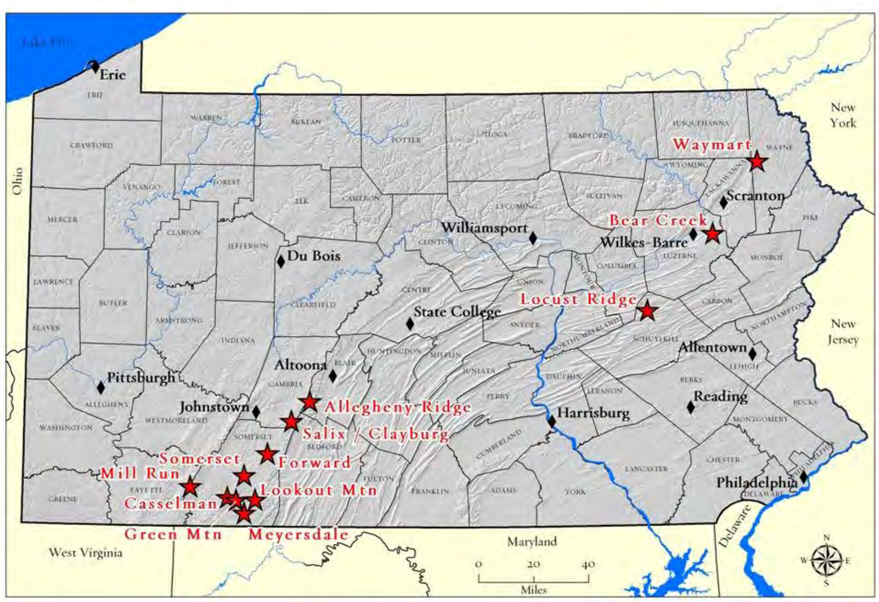
2.5 MW (the average was 1.8 MW in 2009) and reach over 400 feet to the tip of the rotor at the apex of its rotation.

Location is everything for wind development in the northeastern United States. Unlike the vast windswept plains in the Midwest and the intermountain West, high wind speeds in the Northeast are primarily confined to mountain ridgetops, plateau escarpments, and the Atlantic and Great Lake shorelines. Areas that have a wind power class rating of 3 or more (300 watts per m^2) are potentially feasible for wind power development. Wind companies will lease areas that seem to have the most favorable characteristics including wind class, flat pad sites, proximity to transmission lines, and proximity to existing highways. Before development, a wind development company will typically place an anemometer tower on potential development sites to improve knowledge about wind power at the site during a year or longer monitoring period. The turbines are mounted on pads at least 800 feet apart with an access road between towers. The average size of wind facilities has been growing steadily since the first eight were established in 2000. The two largest facilities are now between 75 and 100 turbines.

Several steps have been taken to address potential conflicts between wind development and wildlife in Pennsylvania. The Pennsylvania Game Commission (PGC) has a voluntary agreement in place with most wind companies active in the state to screen proposed facilities for possible impacts to birds and bats and migratory pathways. Participating wind companies carry out pre-construction monitoring for birds and bats. If possible conflicts are identified, PGC works with wind companies to avoid or minimize impacts and to continue monitoring post construction in some cases. Second, the Pennsylvania Wind and Wildlife Collaborative (PWWC) was established in 2005 with a state goal to develop a set of “Pennsylvania-specific principles, policies and best management practices, guidelines and tools to assess risks to habitat and wildlife, and to mitigate for the impact of that development.” Several studies on wildlife and habitat issues have been commissioned, though guidelines and Best Management Practices (BMPs) have not been released.

Current and Projected Wind Energy Development

We documented the spatial foot print of 319 wind turbines at 12 wind facilities across the state by comparing aerial photos taken before and after development. Turbine pads, roads, and other new clearings were digitized for all 12 facilities visible in 2008 images from the

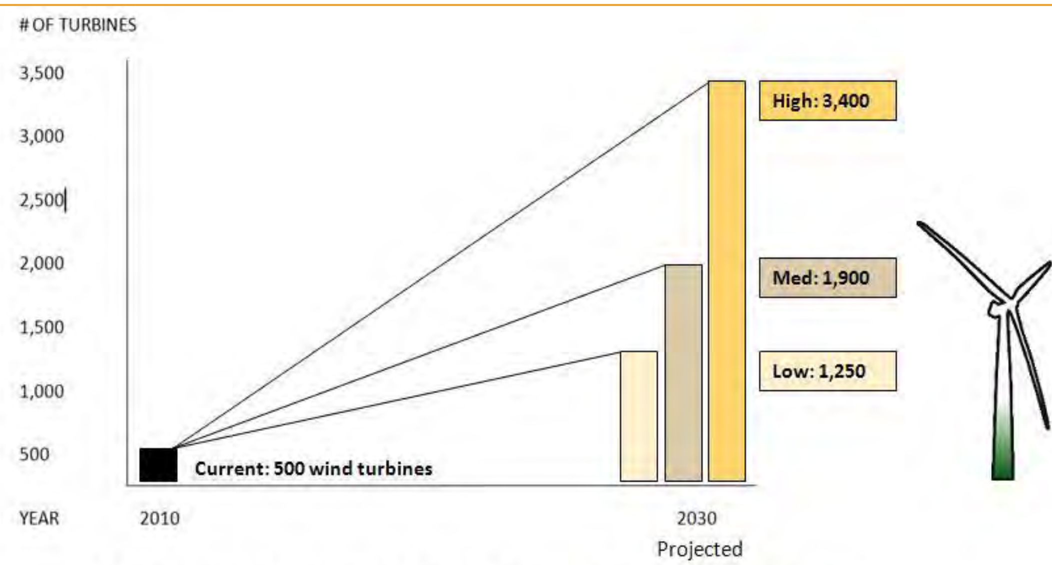


Map showing 12 wind facilities included in the spatial footprint analysis.

Average Spatial Disturbance for Wind Energy Development in Forested Context (acres)		
Forest cleared for wind turbine	**1.4**	**1.9**
Forest cleared for associated infrastructure (roads, other cleared areas)	**0.5**	
Indirect forest impact from new edges	**13.4**	
TOTAL DIRECT AND INDIRECT IMPACTS	**15.3**	

National Agriculture Imagery Program. The ground excavated for turbines, roads, and associated infrastructure (e.g., clearings for constructions staging areas or electrical sub-stations) is the most obvious spatial impact. For each turbine site, turbine pads, new roads, staging areas, and sub-stations were digitized and measured. Turbine pads occupy 1.4 acres on average, while the associated infrastructure (roads, staging areas, and substations) takes up an additional half acre, for a total of 1.9 acres of spatial impact per wind turbine.

As with Marcellus gas development, adjacent lands can also be impacted even if they are not directly cleared (See p. 11 for a description of forest edge impacts on forest "interior" species). To assess the potential interior forest habitat impact, we created a 330 foot buffer into forest patches from new edges created by wind turbine and associated infrastructure development. For turbine sites developed in forest areas (about 80% of the 319 turbines), an average area of 13.4 acres of interior forest habitat was lost in addition to the 1.9 acres of directly cleared forest.



Key drivers: Alternative Energy Portfolio Standard (AEPS) and projected contribution of wind to meeting that standard.

We project between 1,250 and 3,400 total wind turbines will be erected in Pennsylvania by 2030.

The number of wind turbines built in Pennsylvania will certainly expand during the next two decades. Various factors will drive exactly how many turbines are ultimately built including electricity prices, state and federal incentives, technological improvements, energy and climate policy, regulatory changes, and social preferences. Our projections assume economic, policy, and social conditions will remain favorable enough to promote steady expansion of wind development in the state since we cannot reasonably forecast energy prices, technological developments, and policy conditions. The key driver in our low scenario is that companies will use wind energy to meet 70 percent of the current Alternative Energy Portfolio Standard (AEPS) Tier 1 standard (8 percent of electric generation). This projection indicates an additional 750 turbines (2 MW average) will be added to the 500 turbines currently operating. The key driver in our medium scenario is that utilities will use wind energy to meet 70 percent of an expanded AEPS 15% Tier 1 standard, as proposed in recent draft legislation. That scenario would add 1,400 new turbines to those already built. The high scenario used in this assessment is based on the 20% wind power electric generation scenario used by the National Renewable Energy Laboratory in the Eastern Wind Integration Study (EWITS). This scenario would require 2,900 additional turbines.

Where are those new turbines in each scenario more and less likely to go? To start, we created a probability surface by looking at a range of variables that might be relevant to a company's decision to develop a wind facility with wind turbines that have already been built. We used the maximum entropy modeling approach used to develop the Marcellus gas probability surface (see p. 13) and built the model using 580 existing and permitted wind turbines. Variables that potentially drive wind energy development were chosen based on data availability and included wind power (W/m^2), distance to transmission lines, percent slope, distance to roads, and land cover. An additional 193 existing and permitted wind turbines were used to test the validity of the model's probability surface and the model was found to be 95.8% accurate in predicting existing and permitted turbines from randomly sampled undeveloped areas. The resulting probability map indicates many long, narrow high probability sites along ridge tops, and several wider areas on high plateaus and along the Lake Erie coastline.

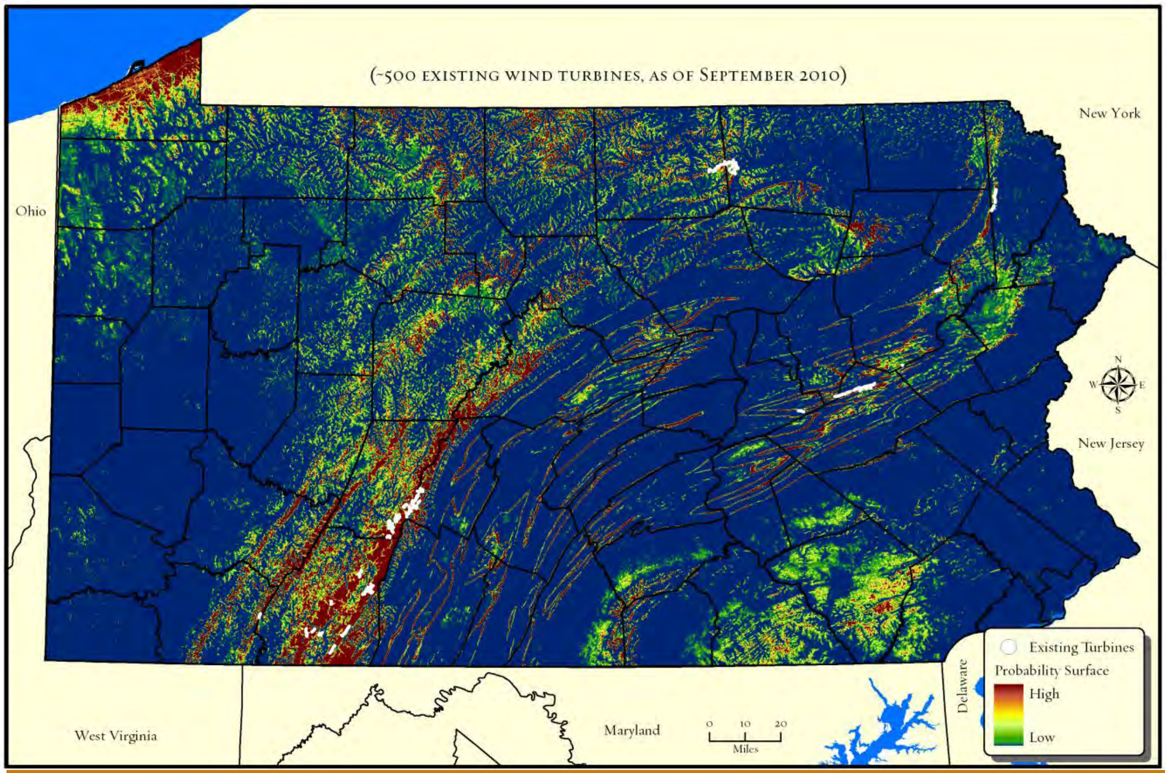
To determine where wind development is more likely, we searched for the highest probability areas where wind turbines in each scenario might be located. The probability surface was re-sampled from 30-meter to 60-meter resolution (0.89 acres) to represent the approximate geographic footprint of wind turbines based on aerial photo assessment. We selected the highest probability pixel, buffered that pixel by a minimum separation distance of 800 feet (240 meters – the average minimum distance between existing turbines), and then selected the next highest probability pixel, and so on. Pixels were selected until the threshold for each scenario was reached (low – 700 turbines; medium – 1,200 turbines; high – 2,700 turbines). The selected pixels were then converted into points for map display purposes.

The resulting projected turbine locations occurred in strings, groups, or scattered single turbines, mostly in southwest, north central and northeastern parts of Pennsylvania. Wind turbines, however, are almost always located in clusters rather than widely separated locations for individual turbines. In order to represent viable wind farms, we selected clusters of pixels with high probability to represent viable wind facilities, based on the following:

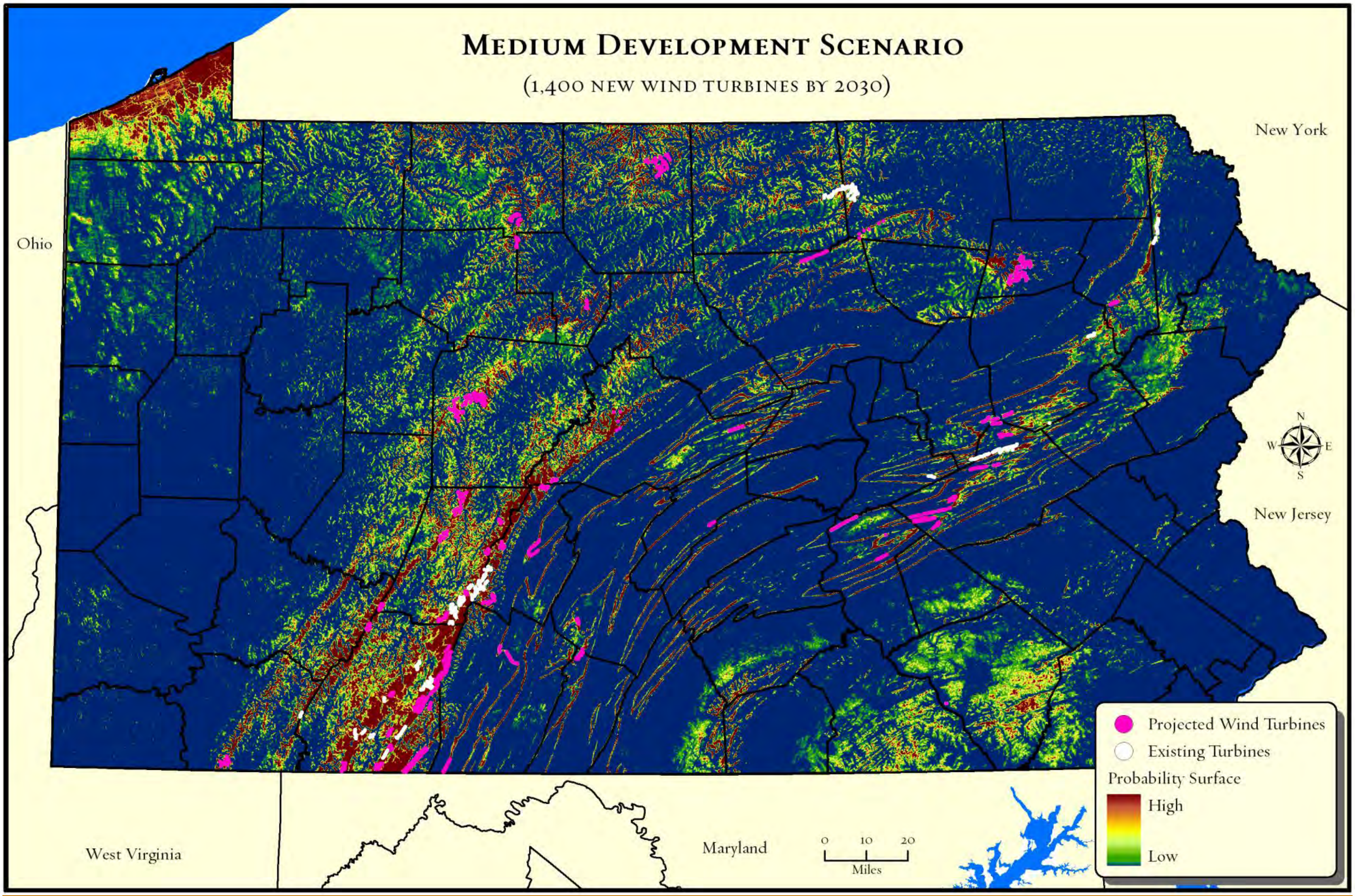
- Excluded areas approximately 300 meters (1,000 ft) from existing homes (as visible in aerial imagery)
- Excluded buffers of regional airports by 6,096 m (20,000 ft) and local airports by 3,048 m (10,000 ft)
- Excluded buffers of existing turbines (buffer = 960 m or 4 times the minimum turbine separation distance of 240 m)
- Excluded Pennsylvania State Parks, Pennsylvania State Forests, and Pennsylvania State Game Lands
- Excluded setbacks of 152 m (500 ft) from the boundaries of state and federal lands

- Required a minimum of 6 projected turbines grouped together to be considered a potentially viable site
- Selected already proposed wind turbines (based on permit data from the Federal Aviation Administration)

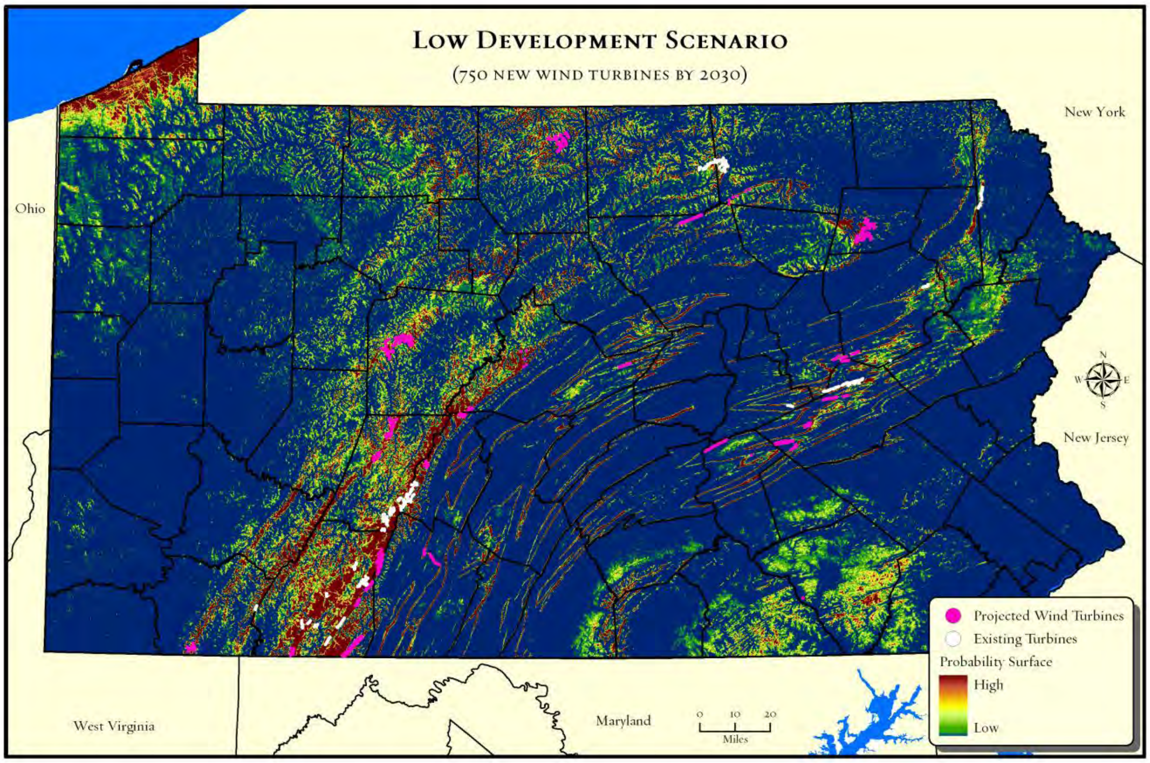
Potential wind facilities were manually selected by identifying groupings of projected wind turbines. Scenarios are cumulative, so the medium scenario includes turbines in both the low and medium scenarios, whereas the high scenario includes all projected turbines.



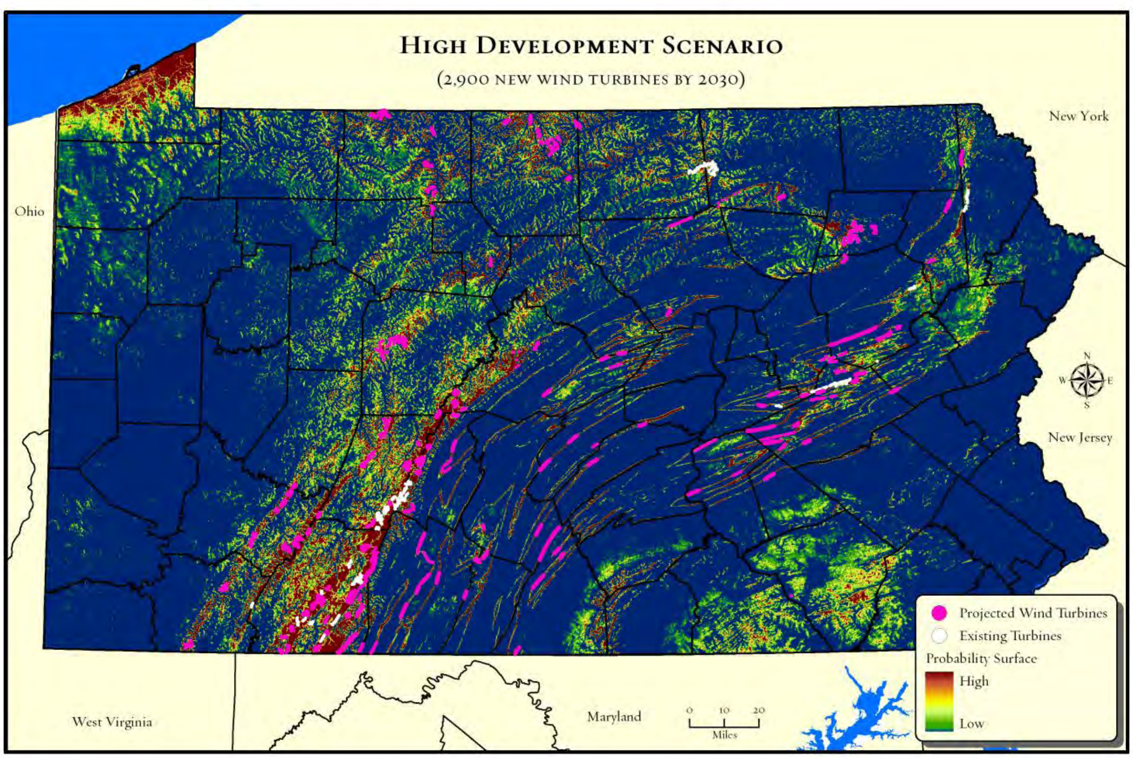
Map showing existing wind turbines with the probability that a given area will be developed indicated by color (dark red is high probability; dark blue is low).



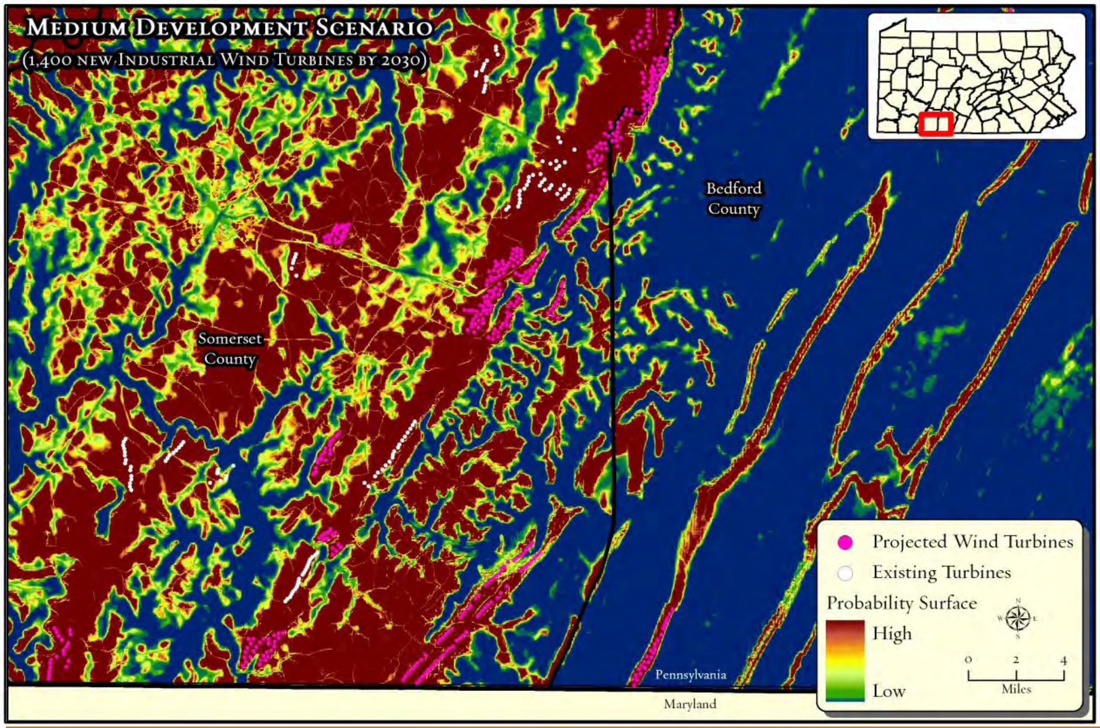
Map showing 1,400 new wind turbines projected by 2030 under the medium development scenario.



Map showing 750 new wind turbines projected by 2030 under the low development scenario.



Map showing 2,900 new wind turbines projected by 2030 under the high development scenario.



Map showing medium wind development scenario within Somerset and Bradford counties.

These geographic projections of future wind energy development are spatial representations of possible scenarios. They are not predictions. We faced several constraints in developing the geographic scenarios:

- We do not have the detailed wind power data that wind companies have developed through anemometer tower monitoring.
- We do not have the detailed location of wind energy leases.

Still, we believe the overall geographic patterns in the projected wind development locations are relatively robust for several reasons. We used over 500 existing or permitted wind turbines to build the model and nearly 200 additional existing and permitted wind turbine sites were used to validate the model. This is typically a sufficient sample size for building predictive models. They are also consistent with Black and Veatch (2010) projected locations for wind facilities under a 15% renewable energy portfolio standard.

Conservation Impacts of Wind Energy Development

What is the overlap of the areas with the highest probability of future wind energy development and those areas known to have high conservation values? To answer this question, we intersected the projected wind energy facilities with high conservation value areas. We looked at several examples from four categories of conservation value, including:

- Forest habitats
- Freshwater habitats

- Species of conservation concern
- Outdoor recreation

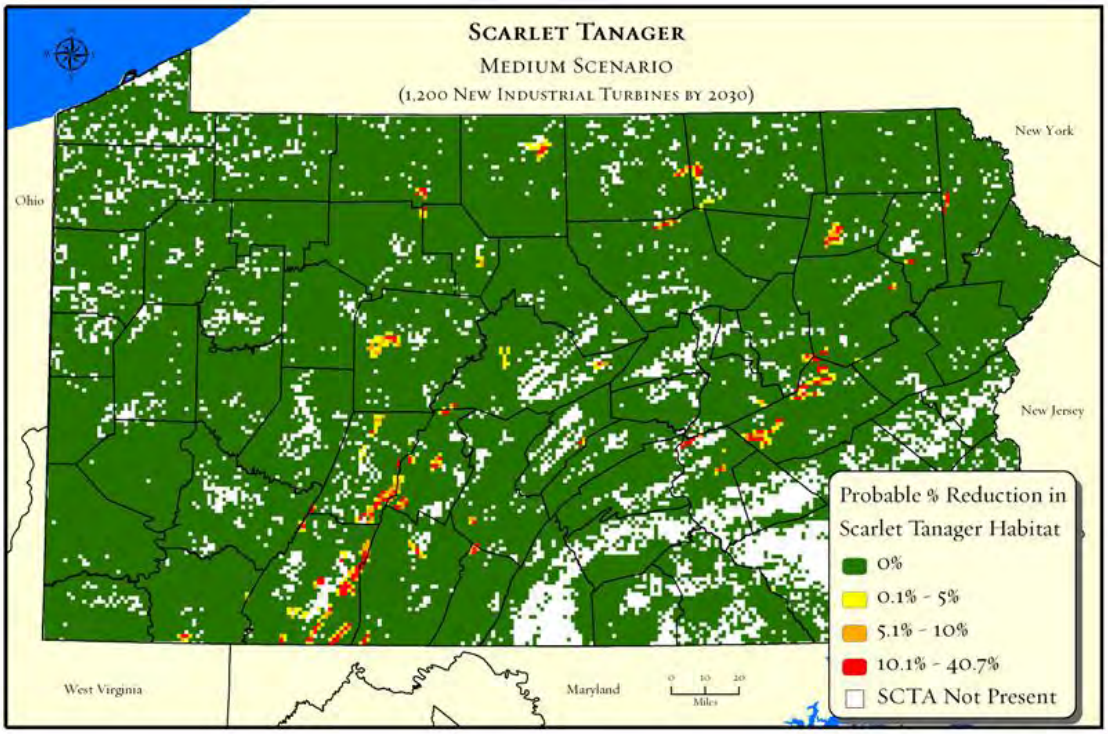
Areas of overlap between likely future wind development areas and priority conservation areas in Pennsylvania are substantially less than the conservation area overlap with likely future Marcellus development areas, largely because the projected foot print will be much smaller.

Forests

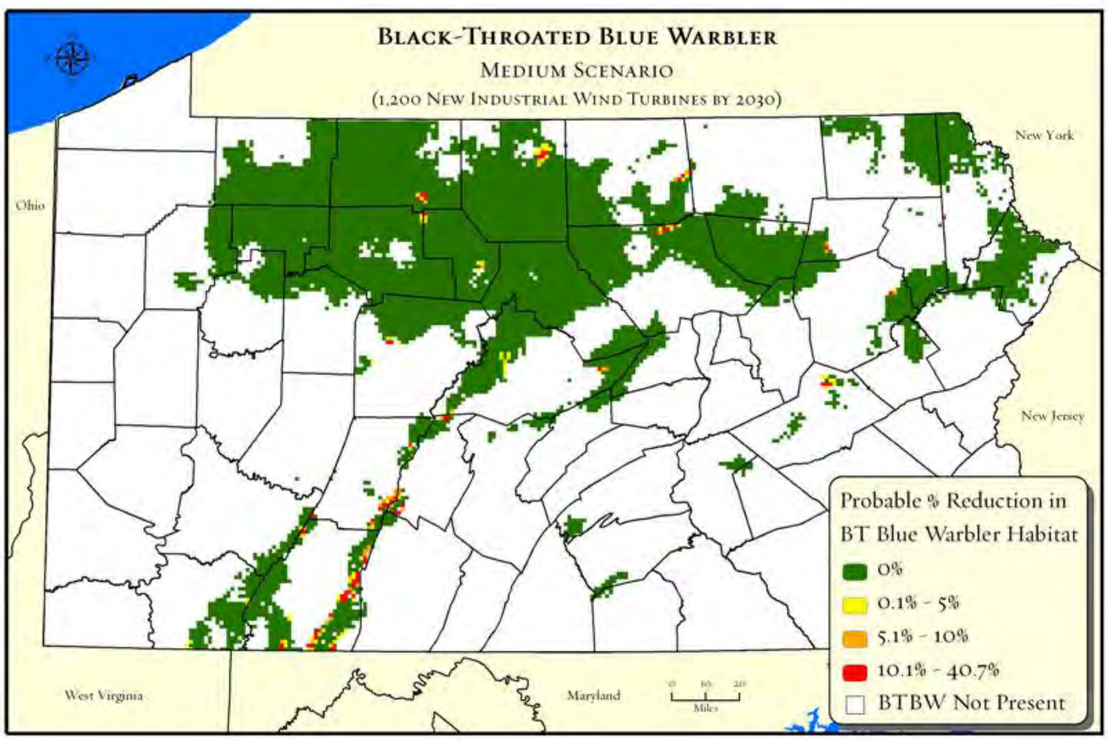
A large majority of projected wind turbines are found in forest patches, about 80 percent for each of the scenarios. The low scenario would see 600 new wind turbines in forest areas. With a cleared forest average of 1.9 acres per turbine (including roads and other infrastructure), the total forest loss would be a modest 1,900 acres. Indirect impacts to adjacent forest interior habitats would total an additional 13,400 acres. Forest impacts from the medium scenario (1,520 projected turbines in forest locations) would be 2,900 cleared forest acres and an additional 20,400 acres of adjacent forest interior habitat impacts. For the high scenario (2,720 turbines in forest areas) 5,200 acres would be cleared and an additional 36,500 acres of forest interior habitats would be affected by new adjacent clearings. On a statewide basis, the projected forest losses and accompanying interior forest habitat impacts will be minor given the Pennsylvania's 16 million acres of forest. Locally, these impacts could be significant for individual large forest patches where wind development takes place.

All forests have conservation value, but large contiguous forest patches are especially valuable because they sustain wide-ranging forest species, such as northern goshawk, than small patches. They are also more resistant to the spread of invasive species, can better withstand damage from wind and ice storms, and provide more ecosystem services – from carbon sequestration to water filtration – than small patches. The Nature Conservancy and the Western Pennsylvania Conservancy's Forest Conservation Analysis mapped nearly 25,000 forest patches in the state greater than 100 acres. Patches at least 1,000 acres in size are about a tenth of the total (2,700). The medium projected wind development scenarios indicate 73 patches (3%) greater than 1,000 acres in size are projected to have at least one wind turbine and associated infrastructure. Patches at least 5,000 acres in size are relatively rare (only 316 patches). The medium wind scenario indicates about 21 (7%) of these patches could be affected by future wind turbine development. Most affected large patches have multiple projected wind turbines (as many as 36). Typically, a large patch is split by wind development into two or three smaller patches due the linear pattern of development. Projected gas well pads, by contrast, are more likely to fragment a large patch into multiple smaller patches.

Forest interior bird species could be affected by the clearing of forest and adjacent edge effects that wind turbine facilities create in a forest context. We used data from the 2nd Breeding Bird Atlas Project (see p. 20) to assess the potential impact on forest interior species. The resulting maps show the estimated reduction in habitat for that species in each high wind development gas probability pixel (including both cleared forest and adjacent edge effects). Scarlet Tanagers are perhaps the most widespread forest interior nesting bird in the state. Since they are so widespread, the vast majority of their range in the state is outside of the most likely wind development areas. Scarlet Tanager populations could decline by an insignificant amount due to habitat losses projected in the medium scenario. Black-throated blue warblers are more narrowly distributed in Pennsylvania favoring mature northern hardwood and coniferous forests with a thick understory, frequently in mountain terrain. Likewise, population declines would also be extremely small for Black-throated blue warblers under the medium scenario.



Map showing estimated percent loss of habitat for Scarlet Tanagers under the medium wind scenario.

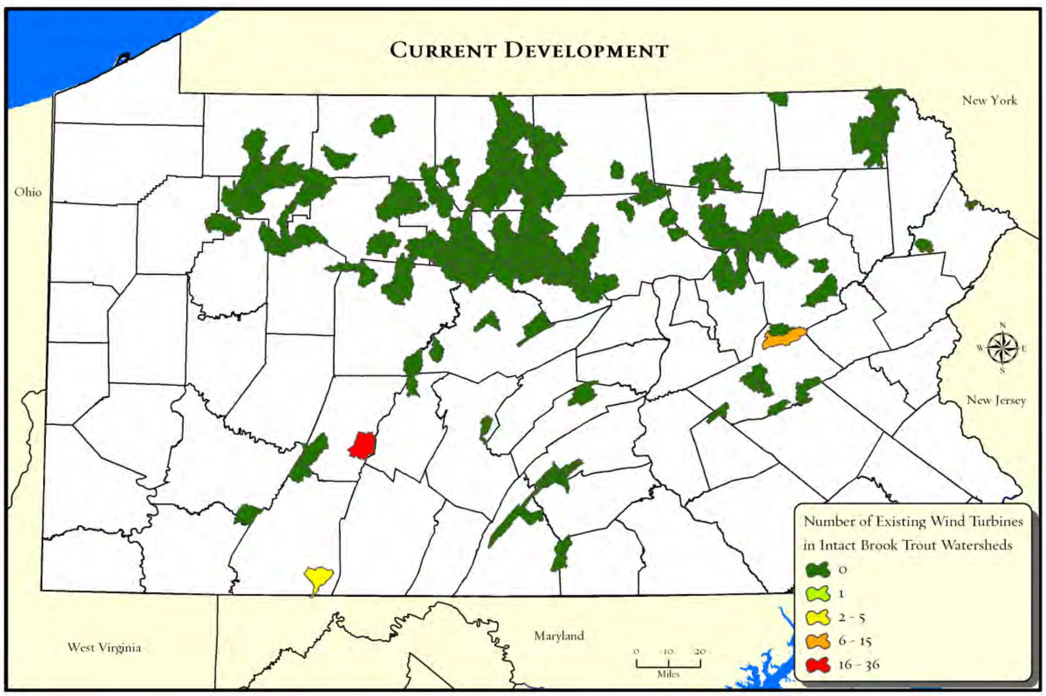


Map showing estimated percent loss of habitat for Black-Throated Blue Warblers under the medium wind scenario.

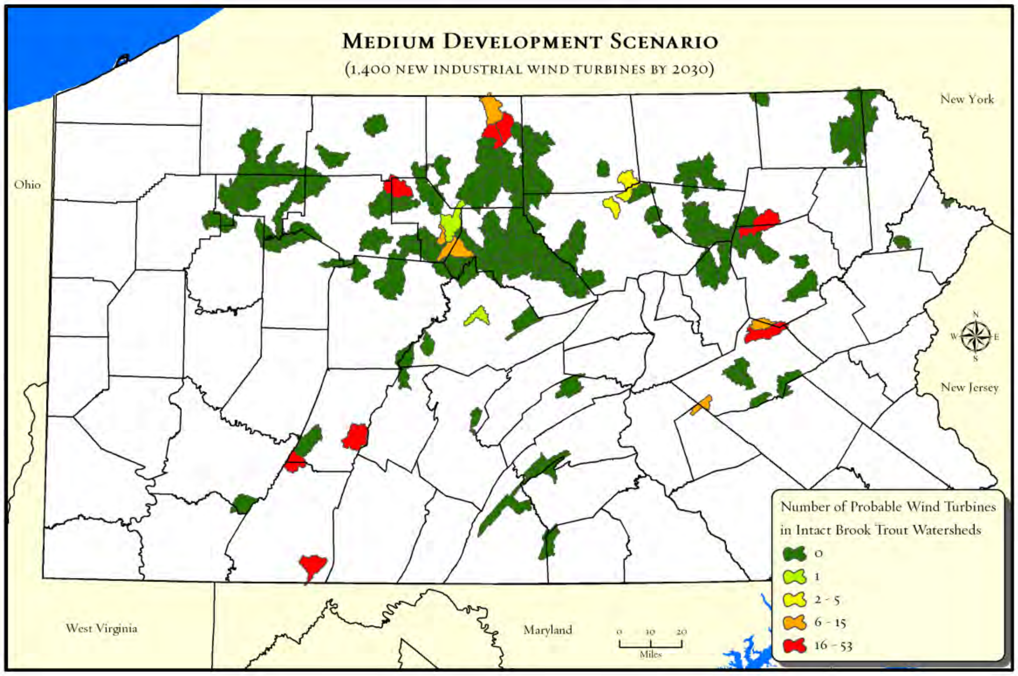
Freshwater

Wind energy and freshwater habitats are not often thought of in the same context since most wind facilities are generally in high elevation areas away from rivers and streams. The exceptions are small headwater streams, some of which may be classified as Exceptional Value watersheds. Our medium scenario projection indicates that 9 percent of future turbine development could be located within ½ mile of an Exceptional Value stream.

Native brook trout are one of the most sensitive species in Pennsylvania watersheds. Brook trout favor cold, highly-oxygenated water and are unusually sensitive to warmer temperatures, sediments, and contaminants. Once widely distributed across Pennsylvania, healthy populations have retreated to a shrinking number of small watersheds. The potential impact on intact brook trout watersheds, however, does increase significantly between the low to high scenarios. Wind turbines have been built in just five of the intact brook trout watersheds identified by the Eastern Brook Trout Joint Venture. That number would expand to 13 in the low scenario, 19 in the medium scenario, and 28 in the high scenario. The presence of wind turbines may pose a limited risk in many of these watersheds, principally from soil disturbance near headwater streams.



Map showing current number of wind turbines in intact and predicted intact brook trout watersheds.



Map showing projected number of wind turbines in intact brook trout watersheds (by 2030) under medium scenario.

Poorly designed or maintained sedimentation measures, especially on road cuts and stream crossings, is the principal risk to these sensitive populations.

Rare Species

Of the approximately 100,000 species believed to occur in Pennsylvania, just over 1 percent is tracked by The Pennsylvania Natural Heritage Program (PNHP). These species are rare, declining or otherwise considered to be of conservation concern. PNHP records indicate that 77 tracked species have populations within pixels that have a relatively high modeled probability for wind development. Most of these species are commonly found in rocky outcrops and scrub oak/pitch pine barrens habitats on ridgetops across the state. Only a handful of species, however, have more than a few occurrences overlapping with the relatively high probability wind development pixels. For example, the eastern timber rattlesnake (*Crotalus horridus*) and Allegheny woodrat (*Neotoma magister*) are strongly associated with rocky outcrops and talus slopes along or near ridgetops. Six percent of the rattlesnake's known rattlesnake breeding/denning sites and three percent of Allegheny woodrat den sites are located in relatively high wind probability pixels. The den sites are very small sites and do not include foraging areas. The Pennsylvania Natural Heritage Program has developed core habitat polygons for each Allegheny woodrat occurrence. Much larger than the den locations, these polygons indicate a much broader overlap – 43 percent – with relatively high probability pixels for wind development. The Northern long-eared Myotis bat (*Myotis septentrionalis*) has about eight percent of its known winter hibernation and summer roosting areas overlapping with relatively high probability wind development pixels. Ridgetop barrens communities in northeastern Pennsylvania have some of the state's largest concentrations of rare terrestrial species. The Nature Conservancy has mapped these communities, and some of these habitats overlap with high wind areas. In general, there appears to be relatively little overlap between tracked species occurrences in Pennsylvania and likely wind development sites. For a handful of species, there is enough overlap to indicate the importance of surveys early in the project planning stage to identify the presence of rare species and their core habitats.

We have not addressed the potential impact of these scenarios on bird migration patterns and bat foraging populations. For more information on wind development impacts on bird and bat species, please see links to the Pennsylvania Game Commission, U.S. Fish and Wildlife Service, American Wind and Wildlife Institute, and Bat Conservation International.

Recreation

Wind development has not occurred on any state or federal lands in Pennsylvania to date. Since our projections assume there will not be a significant change in state land leasing policies for wind development, we have not projected new wind turbines in State Parks, State Forests or State Game Lands. Our projections, however, do indicate that wind turbines will be located in close proximity (sometimes as close as 500 feet) to many state lands. They are likely to be highly visible in some heavily visited areas, such as Blue Knob State Park in Bedford County, where natural landscape vistas are a prime attraction.

Key Findings

Key findings from the Pennsylvania Energy Impacts Assessment include:

- Projections of between 750 and 2,900 new wind turbines developed on ridgetops and high plateaus by 2030, depending on the size of the Pennsylvania Alternative Energy Portfolio standard. There are currently an estimated 500 wind turbines built in the state.

- Wind turbine facilities are likely to be developed in half of the state's counties, especially along the Allegheny front in western Pennsylvania and on high Central Appalachian ridges in central and northeastern parts of the state;

- Nearly eighty percent of turbine locations are projected to be in forest areas, with forest clearing projected to range between 1,900 and 5,200 acres depending on the number of turbines developed. An additional range of 13,400 to 36,500 acres of forest interior habitat impacts are projected due to new edges created by turbine pads and roads;

- On a statewide basis, the projected forest clearing from turbine development is relatively minor, though some of the state's largest forest patches (>5,000 acres) could be fragmented into smaller patches by projected wind turbine development;

- Impacts on forest interior breeding bird habitats appear to be limited, largely because the overall footprint for the projected wind turbine facilities is small in comparison to the typical breeding range of these species in Pennsylvania. The study did not assess impacts to migratory pathways for birds or foraging bats.

- Relatively few watersheds ranked as "intact" by the Eastern Brook Trout Joint Venture are affected by projected wind turbine development. Several intact watersheds, however, could see several dozen wind turbines. In a number of cases, these small watersheds are projected to see significant Marcellus gas development as well. Given the cumulative impact of these activities, rigorously designed and monitored sediment control measures will be needed to protect sensitive brook trout populations.

- A relatively small handful of rare species occurrences tracked by the Pennsylvania Natural Heritage Program are found in areas with high probability for wind development. These species tend to be associated with rocky outcrops and barrens communities typically found on ridge tops, including the Allegheny wood rat, the eastern timber rattlesnake, and the northern long-eared Myotis bat.

- Wind development is not projected to occur on Pennsylvania's public lands. Existing and projected wind turbines, however, will be close to some of Pennsylvania's most heavily visited outdoor recreation areas where scenic natural vistas are a major attraction.

Additional Information

- American Wind Energy Association (2010). U.S. Wind Projects Database. http://www.awea.org/la_usprojects.cfm
- Black and Veatch (2010). Assessment of a 15 Percent Pennsylvania Alternative Energy Portfolio Standard. Report prepared for the Community Foundation for the Alleghenies, Johnstown, PA. http://www.cfalleghenies.org/pdf/aepss.pdf
- Federal Aviation Administration (FAA) permits for wind turbines: https://oeaaa.faa.gov/oeaaa/external/public/publicAction.jsp?action=showCaseDownloadForm
- Federal Aviation Administration (FAA), Obstruction Evaluation / Airport Airspace Analysis (OE/AAA): https://oeaaa.faa.gov/oeaaa/external/public/publicAction.jsp?action=showCaseDownloadForm
- Pennsylvania Wind Farms and Wildlife Collaborative: http://www.dcnr.state.pa.us/wind/index.aspx
- PA Game Commission (2007) Wind Energy Voluntary Cooperative Agreement and First Annual Report for the Wind Energy Voluntary Cooperative Agreement: http://www.portal.state.pa.us/portal/server.pt?open=514&objID=613068&mode=2
- Pennsylvania Department of Environmental Protection, Chapter 93 Water Quality Standards, Exceptional Value and High Quality Streams: data downloaded from Pennsylvania Spatial Data Access: (www.pasda.psu.edu)
- U.S. Department of Energy TrueWind 80 Meter Wind Resource Maps: http://www.windpoweringamerica.gov/wind_maps.asp
- U.S. Fish and Wildlife Service Wind Turbine Advisory Committee: http://www.fws.gov/habitatconservation/windpower/wind_turbine_advisory_committee.html
- U.S. Environmental Protection Agency summary of forest fragmentation effects: http://cfpub.epa.gov/eroe/index.cfm?fuseaction=detail.viewInd&lv=list.listByAlpha&r=219658&subtop=210
- Overview of forest fragmentation impacts on forest interior nesting species: http://www.state.nj.us/dep/fgw/neomigr.htm
- Overview of Pennsylvania High Quality and Exceptional Value Streams: http://www.dcnr.state.pa.us/wlhabitat/aquatic/streamdist.aspx
- Eastern Brook Trout Joint Venture intact brook trout watersheds: http://128.118.47.58/EBTJV/ebtjv2.html

- Overview of Carnegie Museum of Natural History, Powdermill Nature Reserve, and the Pennsylvania Game Commission's 2nd Pennsylvania Breeding Bird Atlas Project: http://www.carnegiemnh.org/powdermill/atlas/2pbba.html

- Pennsylvania Natural Heritage Program, including lists of globally rare and state endangered and imperiled species: http://www.naturalheritage.state.pa.us/

- U.S. Department of Agriculture, Natural Resources Conservation Service, National Agriculture Imagery Program: http://datagateway.nrcs.usda.gov/GDGOrder.aspx

pennsylvania
DEPARTMENT OF CONSERVATION
AND NATURAL RESOURCES

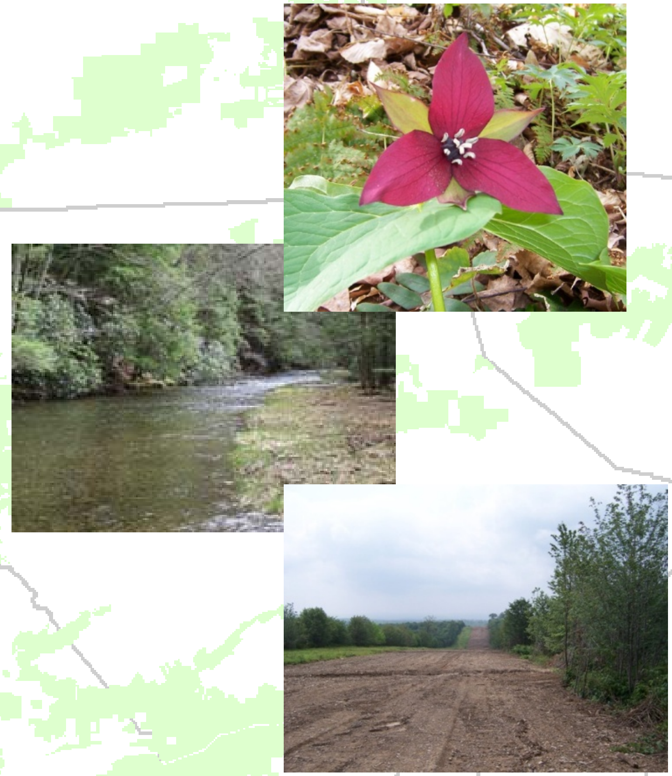
Impacts of Leasing Additional State Forest for Natural Gas Development

pennsylvania
DEPARTMENT OF CONSERVATION
AND NATURAL RESOURCES

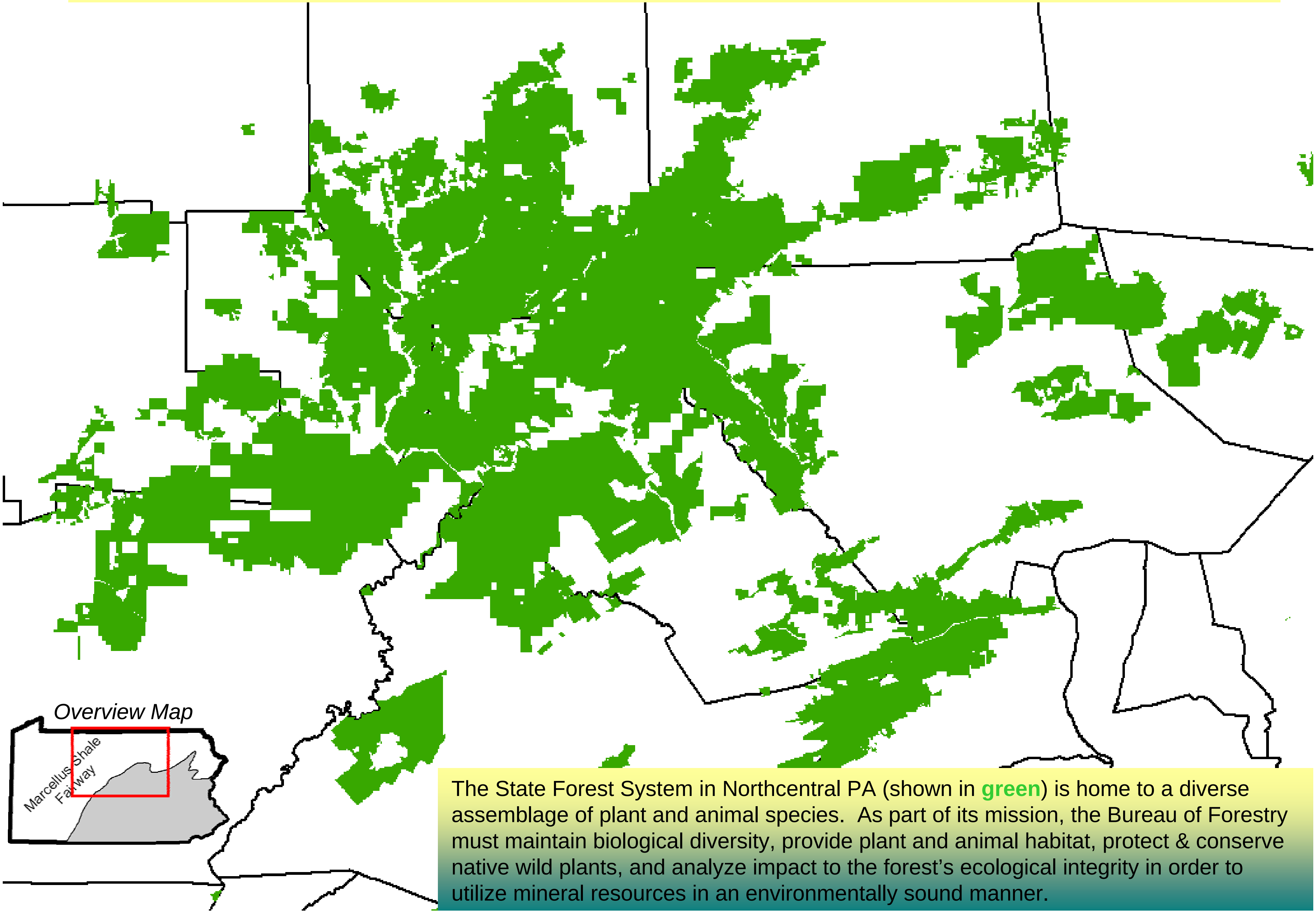
DCNR is entrusted to balance the uses and values of our state forests while protecting the integrity and health of the whole system.

There are proposals and public debate about the merits of a moratorium on natural gas drilling on state forest.

This mapping analysis demonstrates how any additional leasing involving surface disturbance upsets the sustainable balance DCNR is charged to maintain.

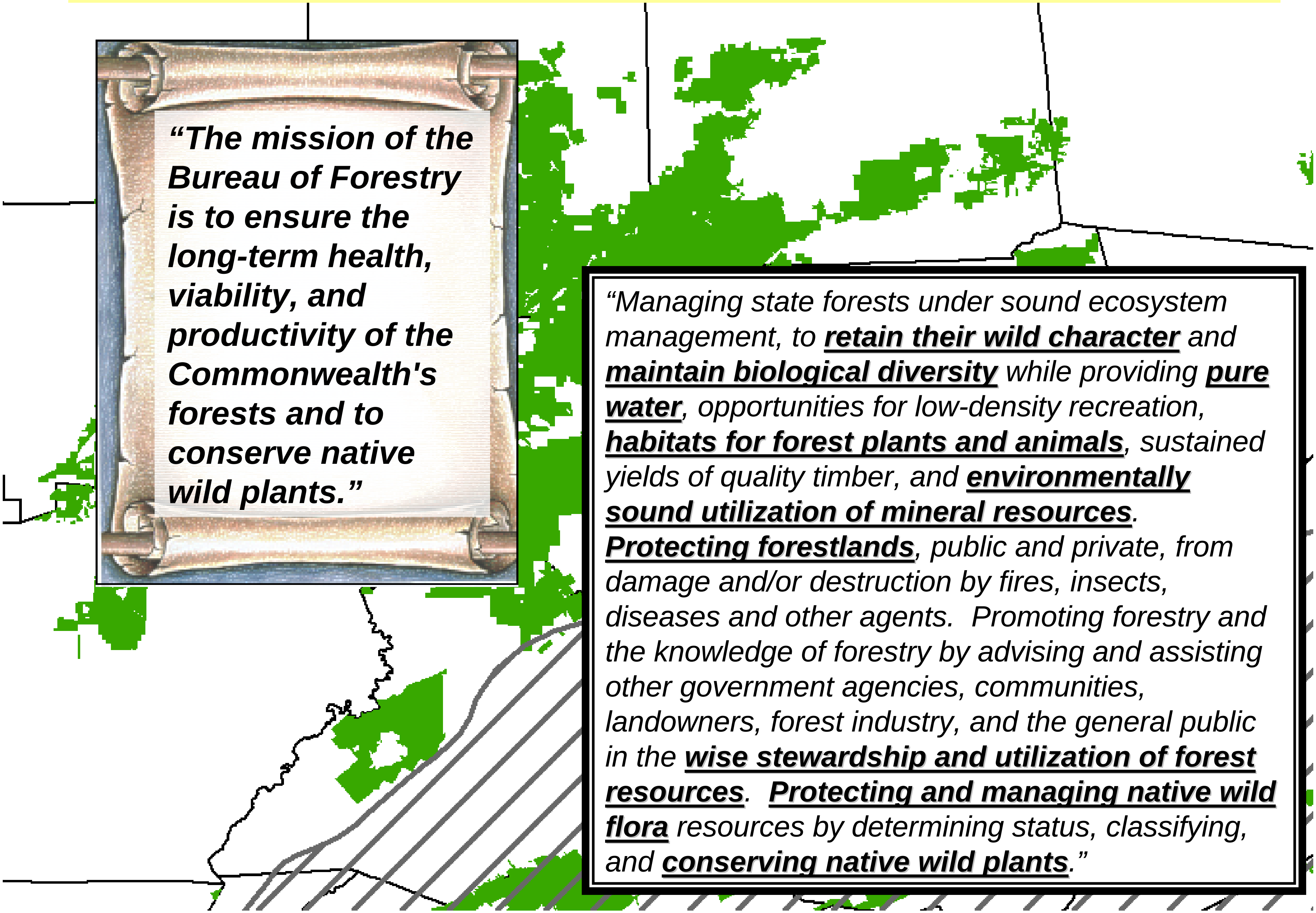


State Forest Land in North-Central Pennsylvania



The State Forest System in Northcentral PA (shown in **green**) is home to a diverse assemblage of plant and animal species. As part of its mission, the Bureau of Forestry must maintain biological diversity, provide plant and animal habitat, protect & conserve native wild plants, and analyze impact to the forest's ecological integrity in order to utilize mineral resources in an environmentally sound manner.

State Forest Land in Northcentral Pennsylvania

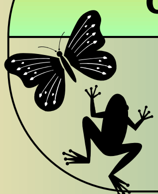


"The mission of the Bureau of Forestry is to ensure the long-term health, viability, and productivity of the Commonwealth's forests and to conserve native wild plants."

*"Managing state forests under sound ecosystem management, to **retain their wild character** and **maintain biological diversity** while providing **pure water**, opportunities for low-density recreation, **habitats for forest plants and animals**, sustained yields of quality timber, and **environmentally sound utilization of mineral resources**. **Protecting forestlands**, public and private, from damage and/or destruction by fires, insects, diseases and other agents. Promoting forestry and the knowledge of forestry by advising and assisting other government agencies, communities, landowners, forest industry, and the general public in the **wise stewardship and utilization of forest resources**. **Protecting and managing native wild flora** resources by determining status, classifying, and **conserving native wild plants**."*

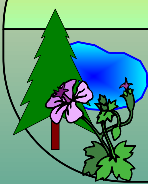
Maintaining the Forest's Ecological Integrity

Species of Concern



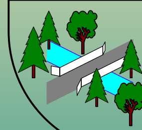
Native Biological Diversity
Threatened / Endangered Spp.
Rare / Declining Spp.

Unique Areas



Wild & Natural Areas
Steep, Wet, & Rocky Areas
Old Growth
Wild Plant Sanctuaries

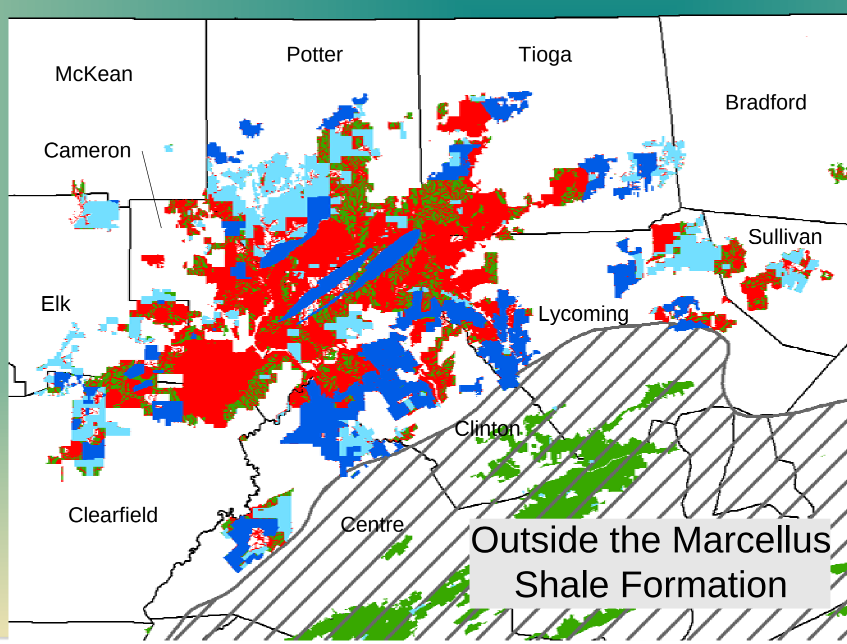
Road, Trail, & Stream Buffers

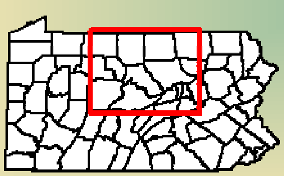


Aesthetics / Scenery
Corridors
Connectivity
Water Quality

Legend

- DCNR Gas Lease
- Severed Rights
- Ecologically Sensitive
- Other State Forest

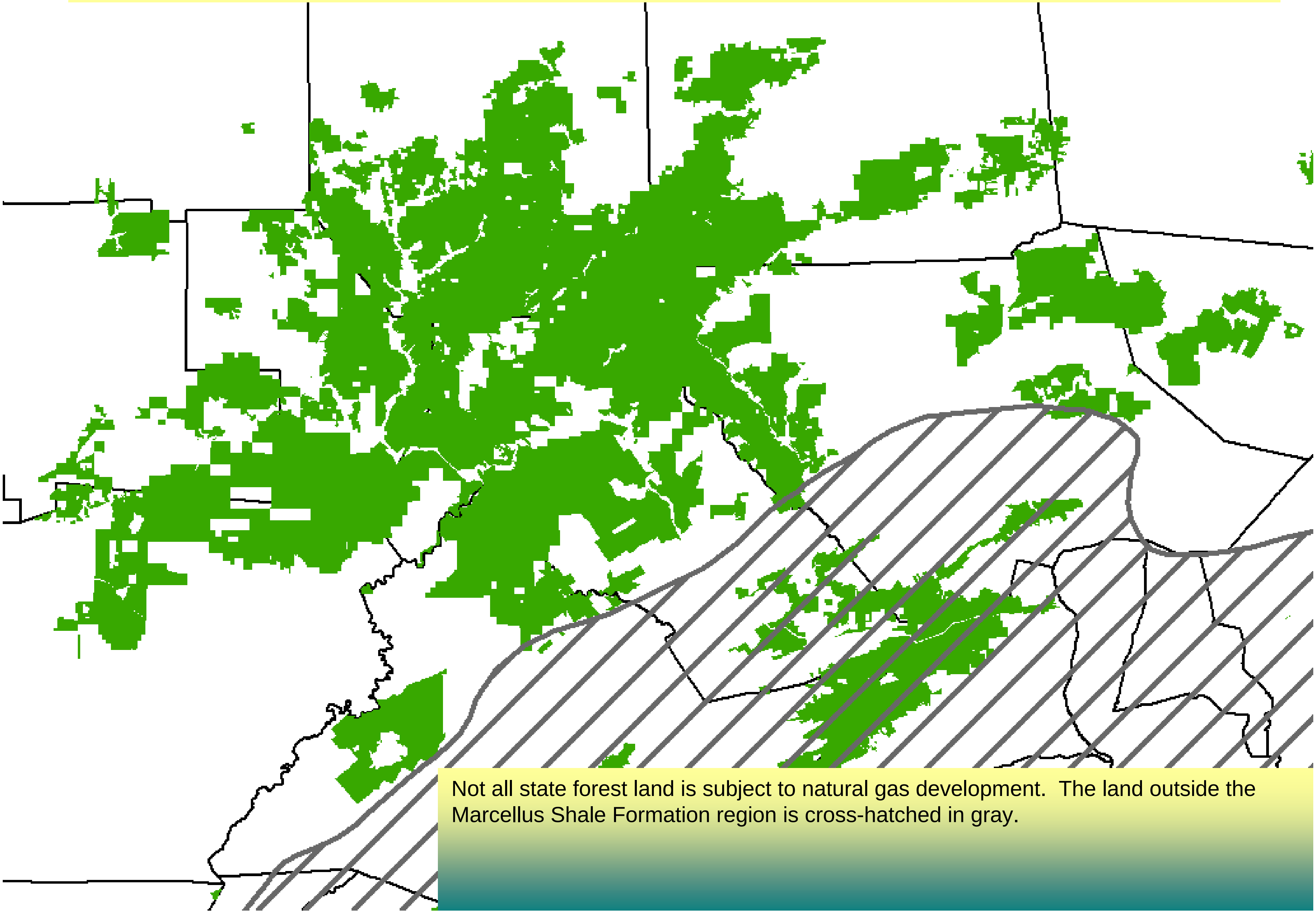




1,500,000 acres — State Forest Land in the Marcellus Shale Region
- 700,000 acres — State Forest Land Currently Leased or Severed
- 702,500 acres — Unleased Land in Ecologically Sensitive Areas

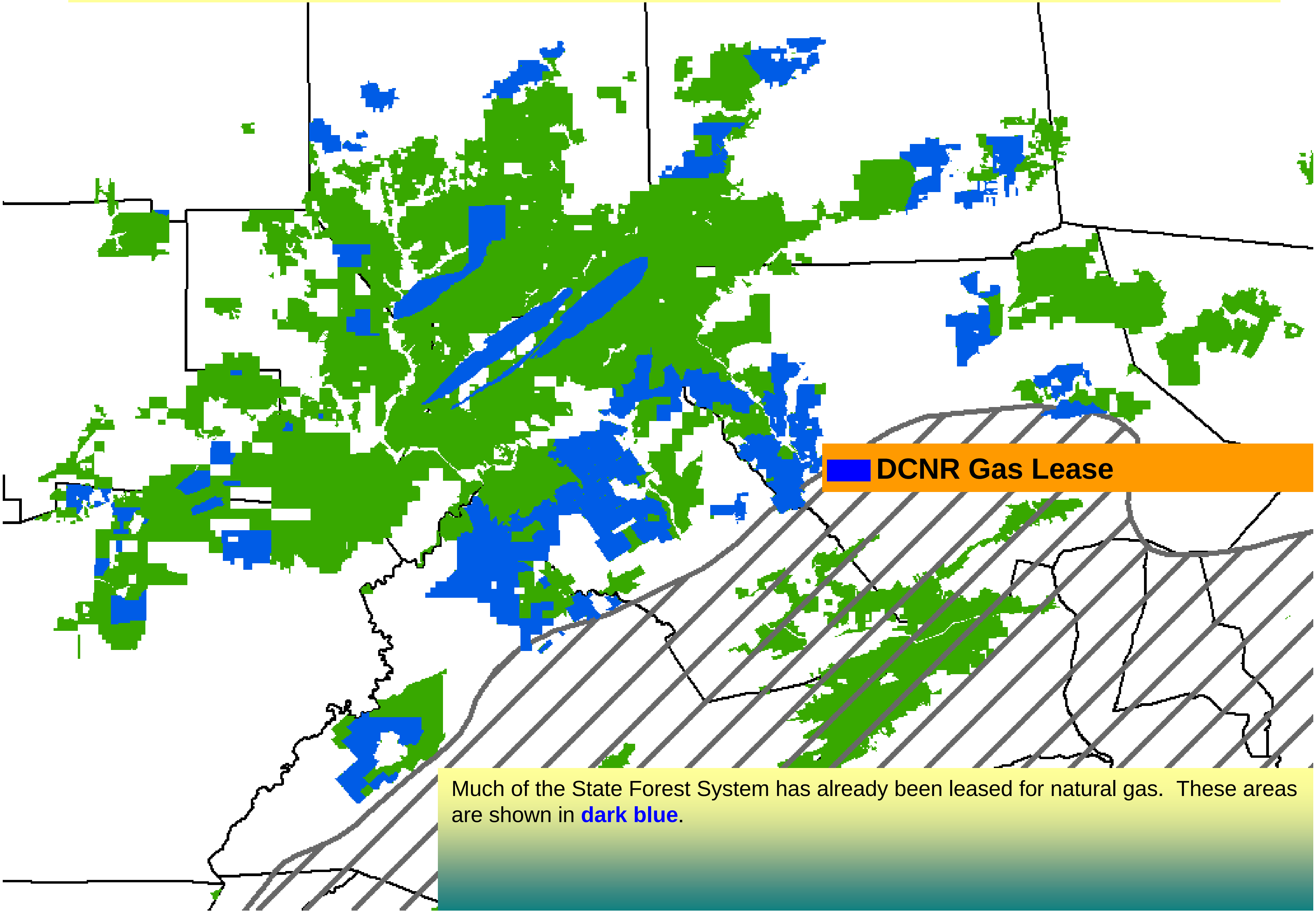
97,500 acres — Inaccessible w/o Damaging Ecologically Sensitive Areas

Maintaining the Forest's Ecological Integrity



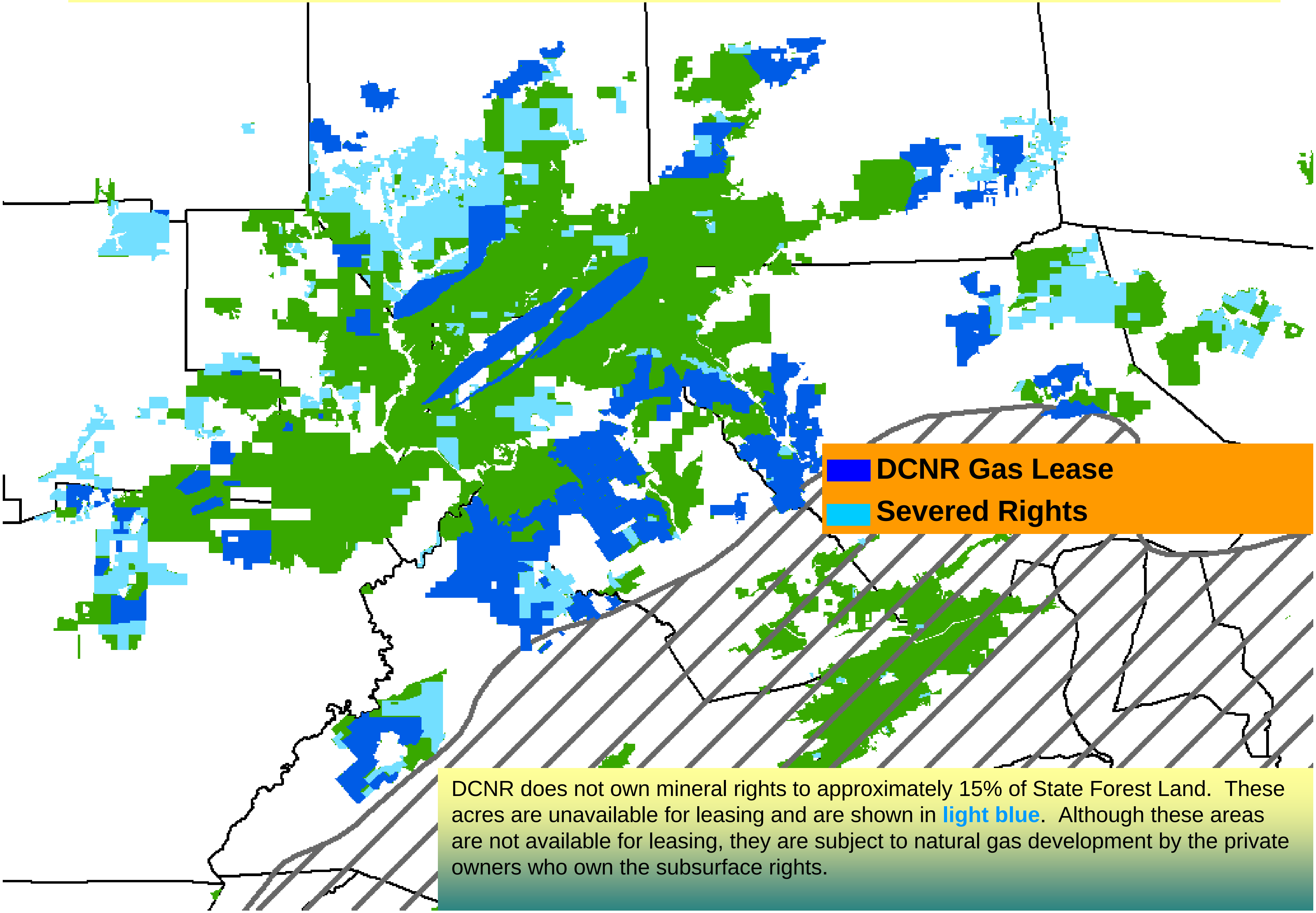
Not all state forest land is subject to natural gas development. The land outside the Marcellus Shale Formation region is cross-hatched in gray.

Maintaining the Forest's Ecological Integrity



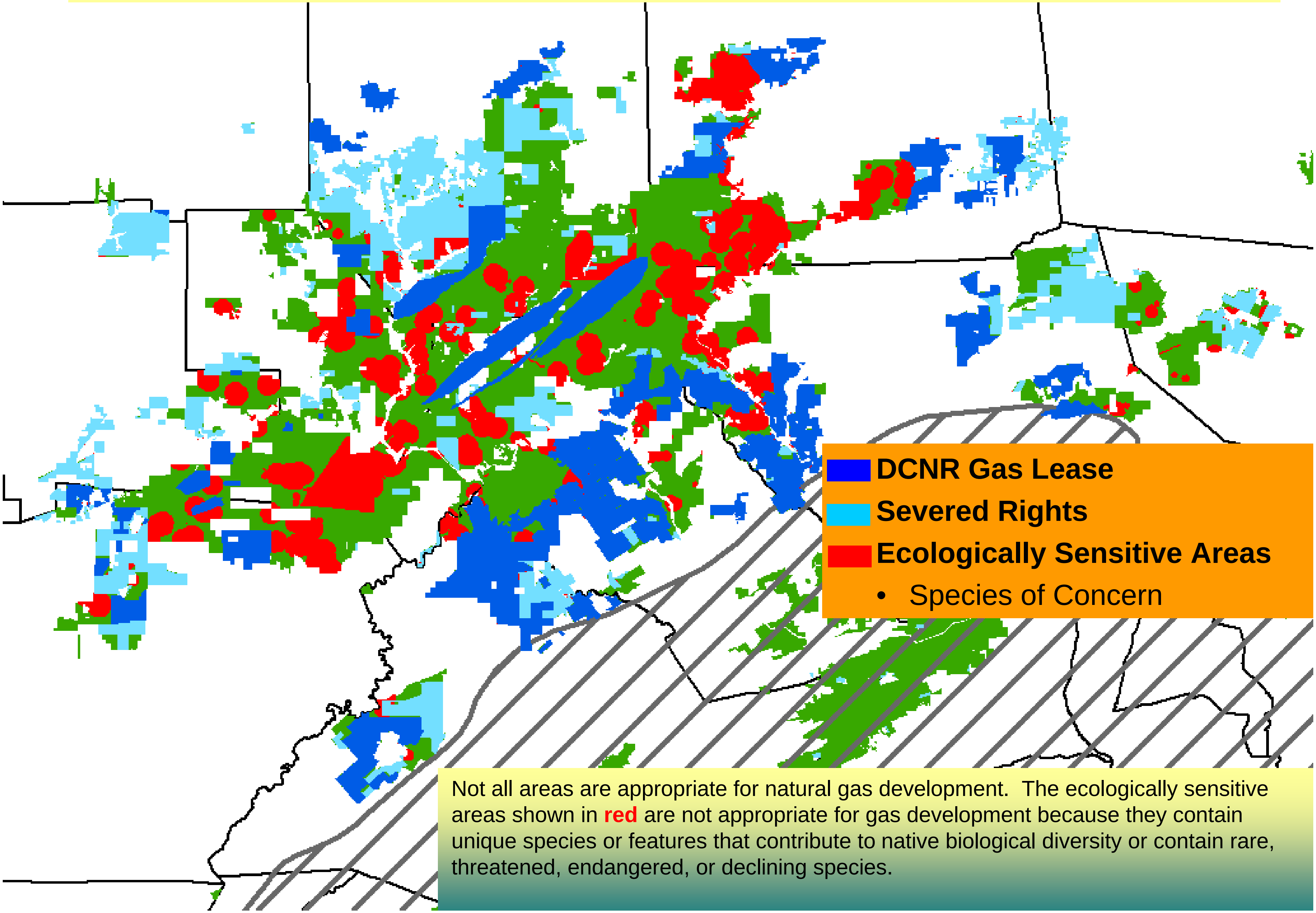
Much of the State Forest System has already been leased for natural gas. These areas are shown in **dark blue**.

Maintaining the Forest's Ecological Integrity



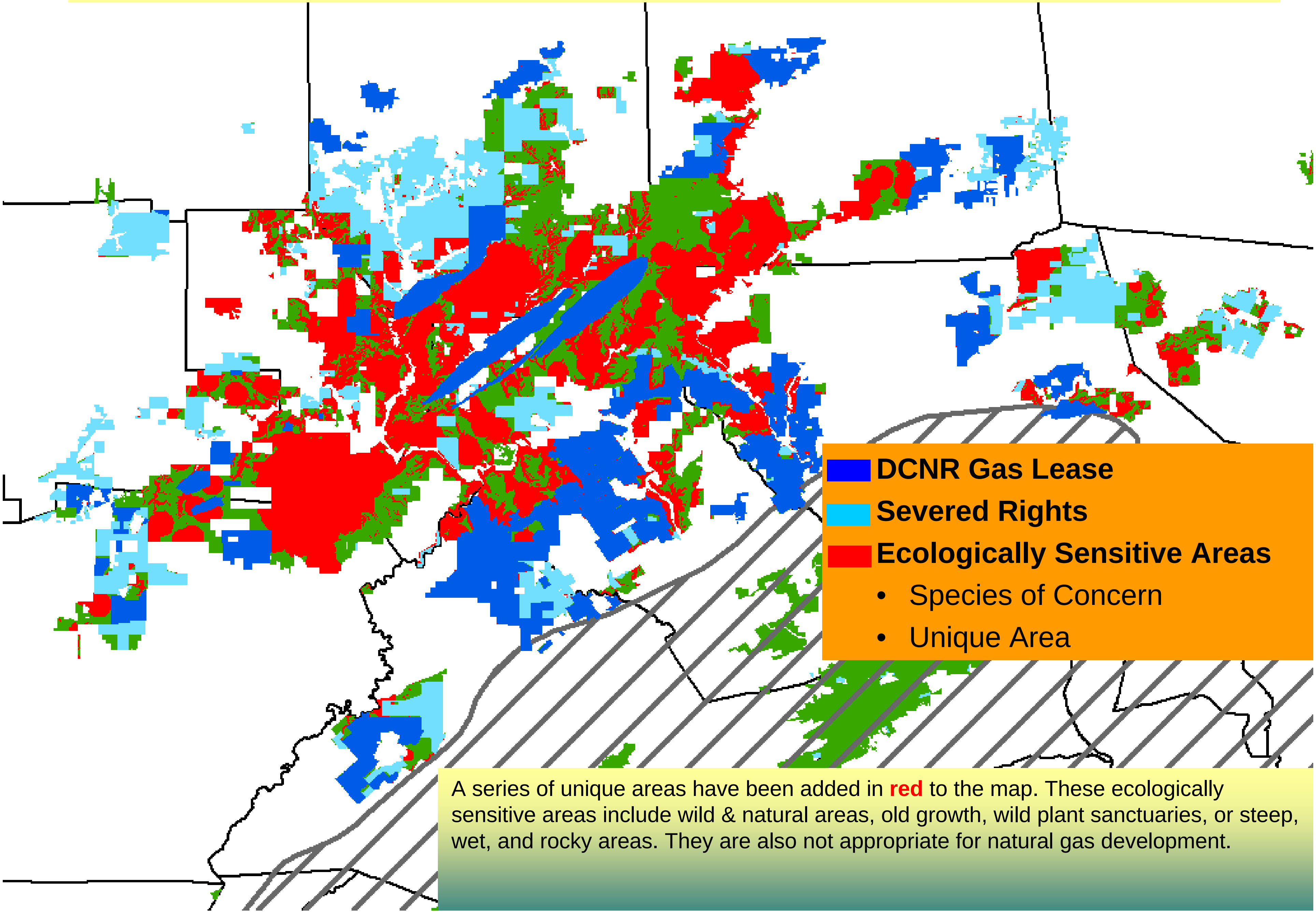
DCNR does not own mineral rights to approximately 15% of State Forest Land. These acres are unavailable for leasing and are shown in **light blue**. Although these areas are not available for leasing, they are subject to natural gas development by the private owners who own the subsurface rights.

Maintaining the Forest's Ecological Integrity



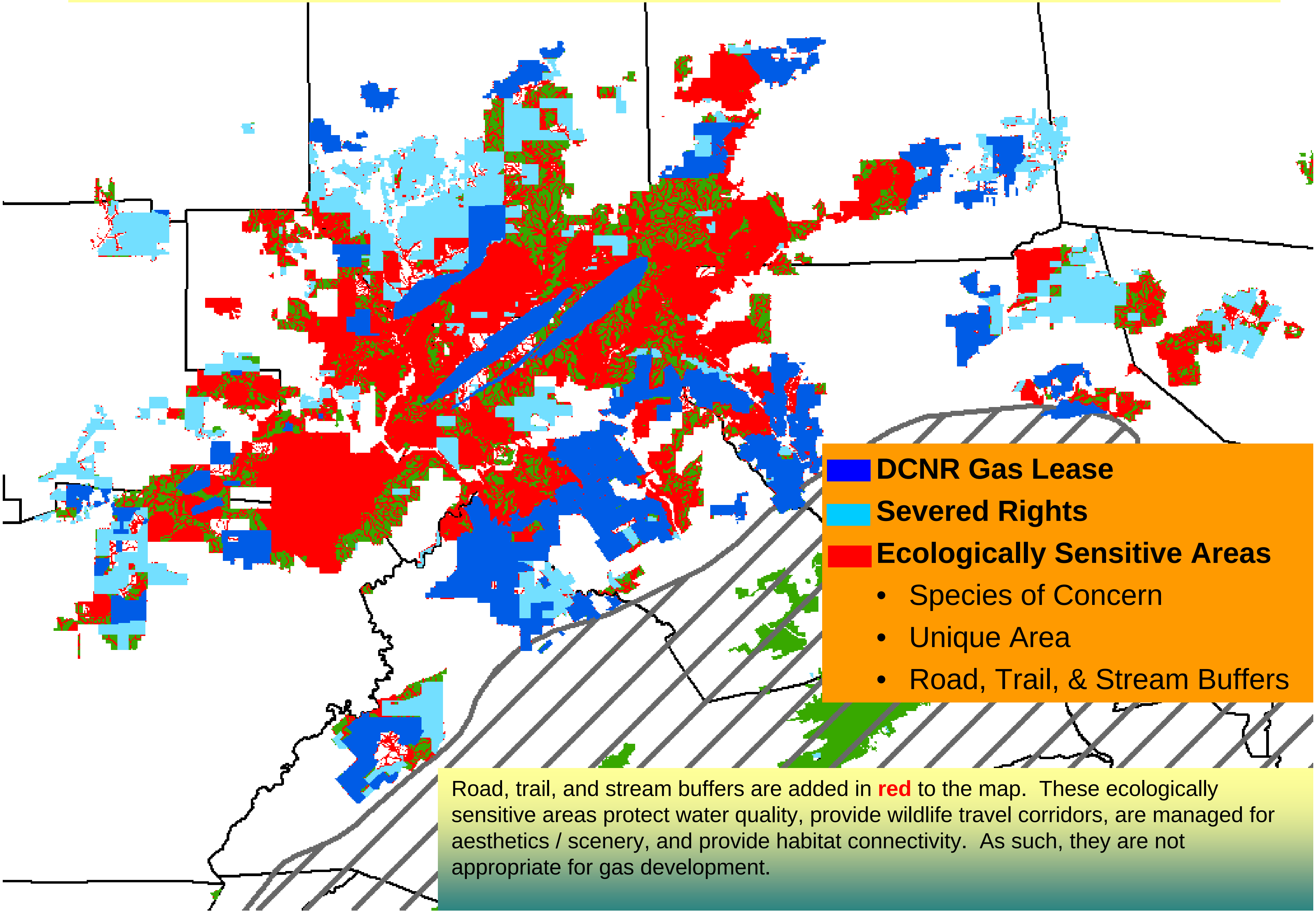
Not all areas are appropriate for natural gas development. The ecologically sensitive areas shown in **red** are not appropriate for gas development because they contain unique species or features that contribute to native biological diversity or contain rare, threatened, endangered, or declining species.

Maintaining the Forest's Ecological Integrity



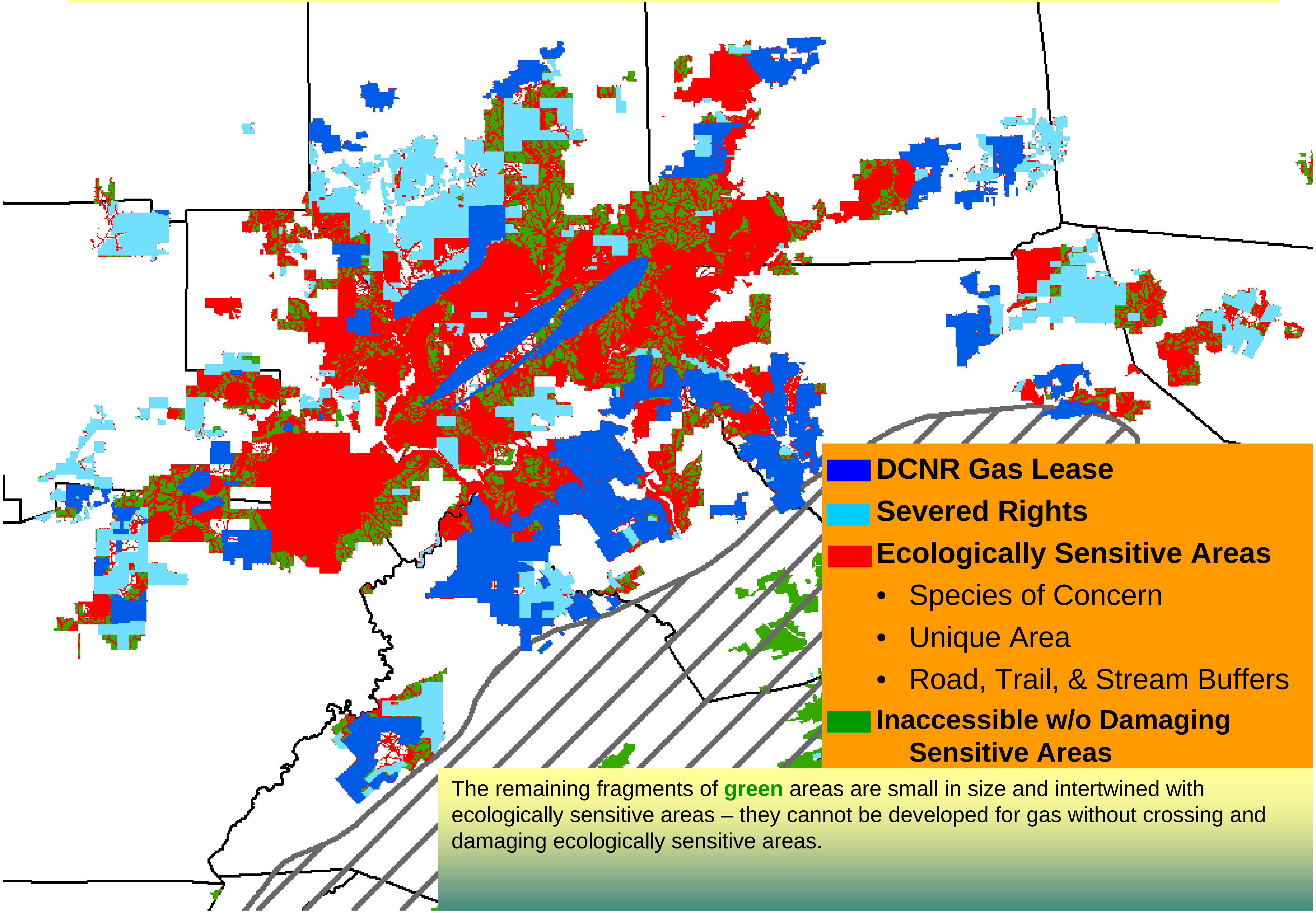
A series of unique areas have been added in **red** to the map. These ecologically sensitive areas include wild & natural areas, old growth, wild plant sanctuaries, or steep, wet, and rocky areas. They are also not appropriate for natural gas development.

Maintaining the Forest's Ecological Integrity



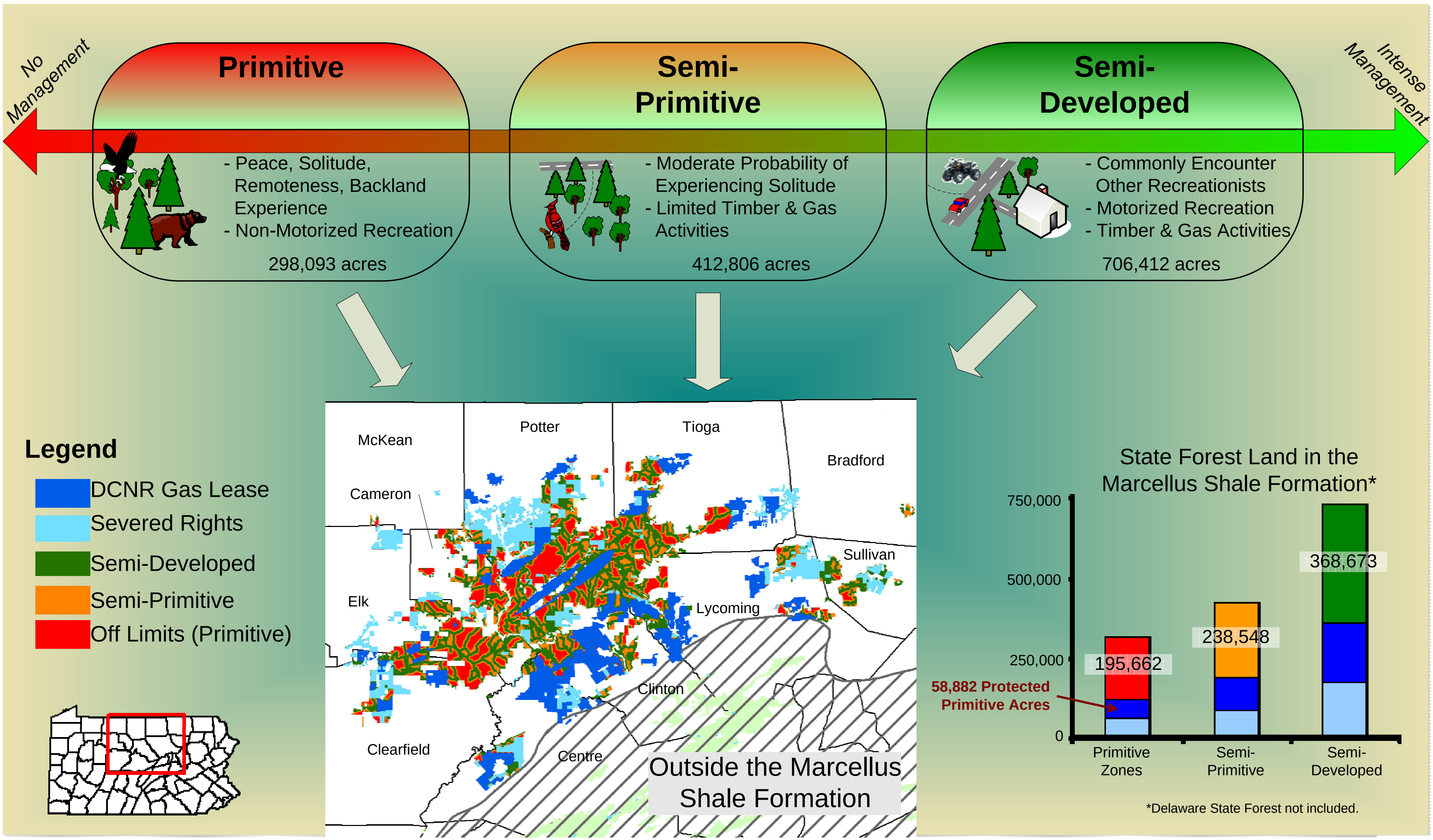
Road, trail, and stream buffers are added in **red** to the map. These ecologically sensitive areas protect water quality, provide wildlife travel corridors, are managed for aesthetics / scenery, and provide habitat connectivity. As such, they are not appropriate for gas development.

Maintaining the Forest's Ecological Integrity

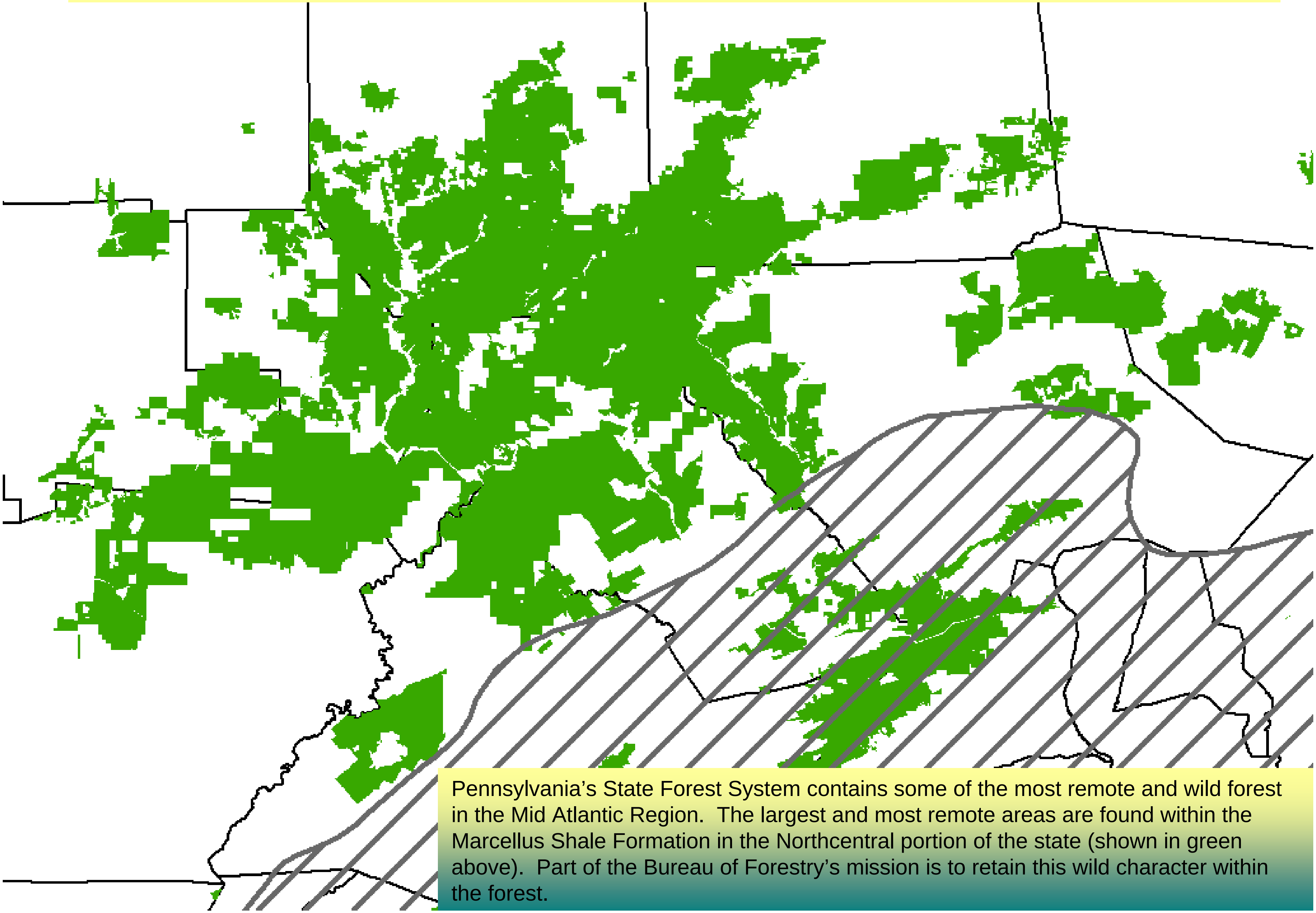


The remaining fragments of **green** areas are small in size and intertwined with ecologically sensitive areas – they cannot be developed for gas without crossing and damaging ecologically sensitive areas.

Maintaining the Forest's Wild Character

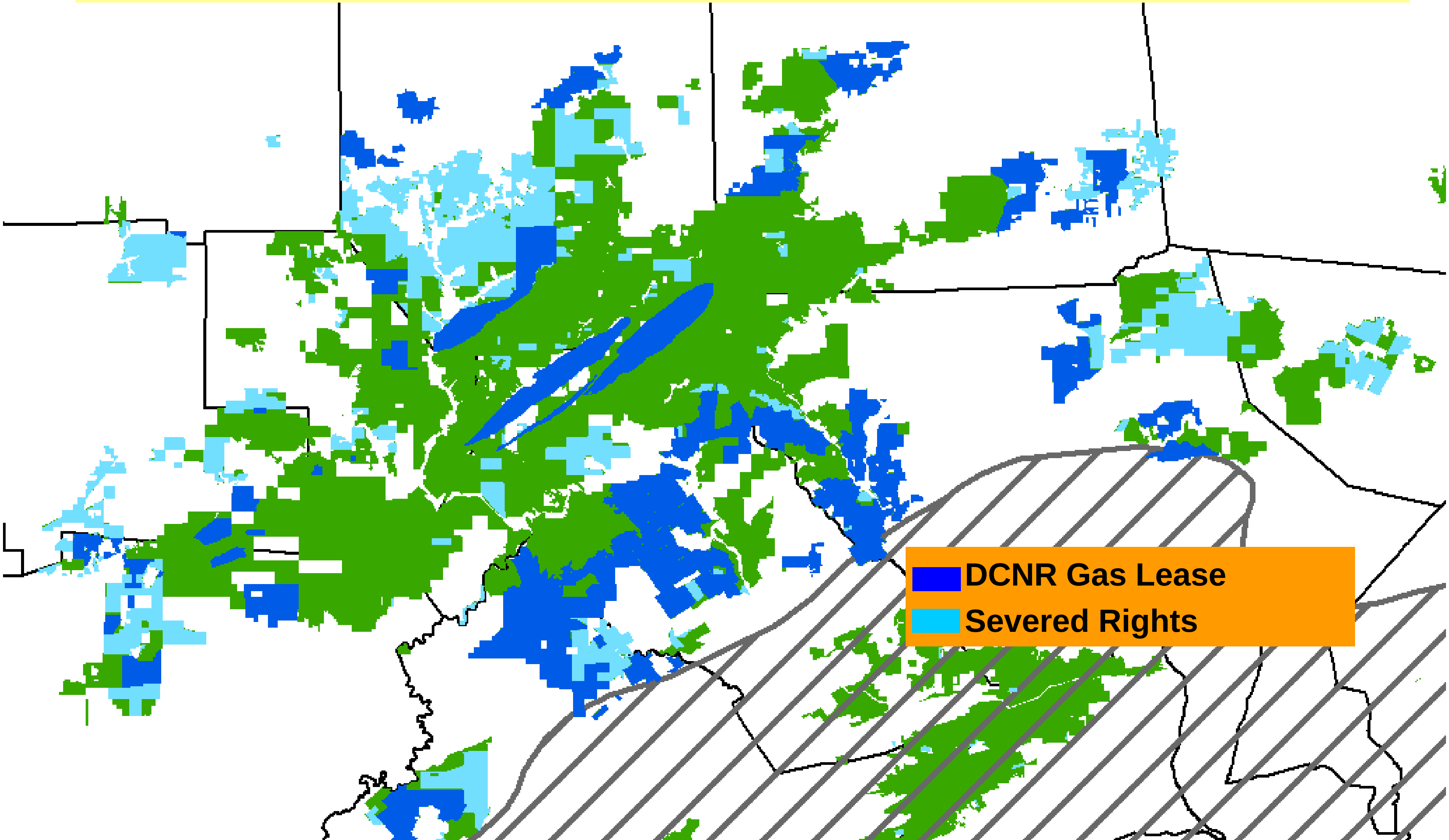


Maintaining the Forest’s Wild Character



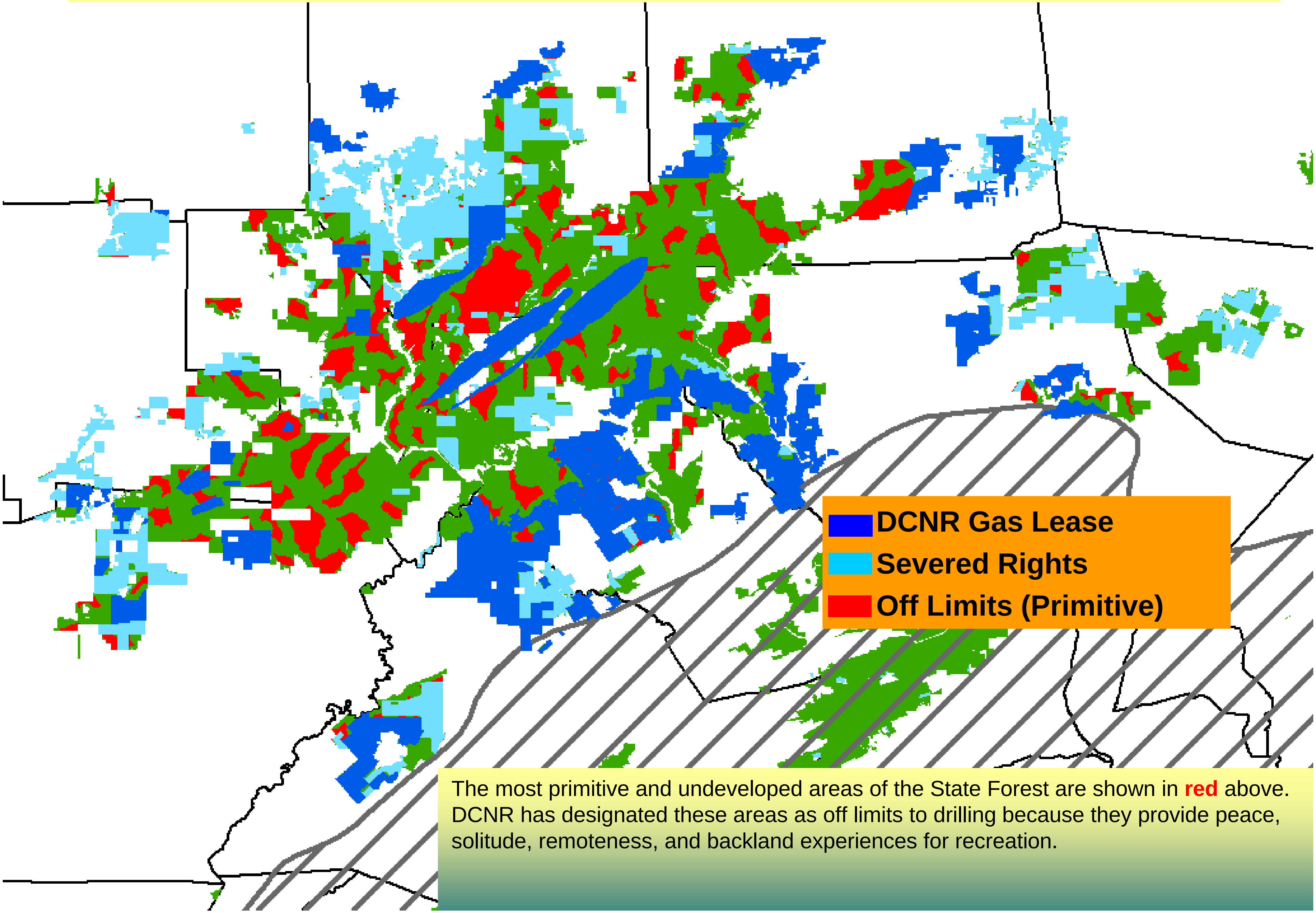
Pennsylvania’s State Forest System contains some of the most remote and wild forest in the Mid Atlantic Region. The largest and most remote areas are found within the Marcellus Shale Formation in the Northcentral portion of the state (shown in green above). Part of the Bureau of Forestry’s mission is to retain this wild character within the forest.

Maintaining the Forest's Wild Character



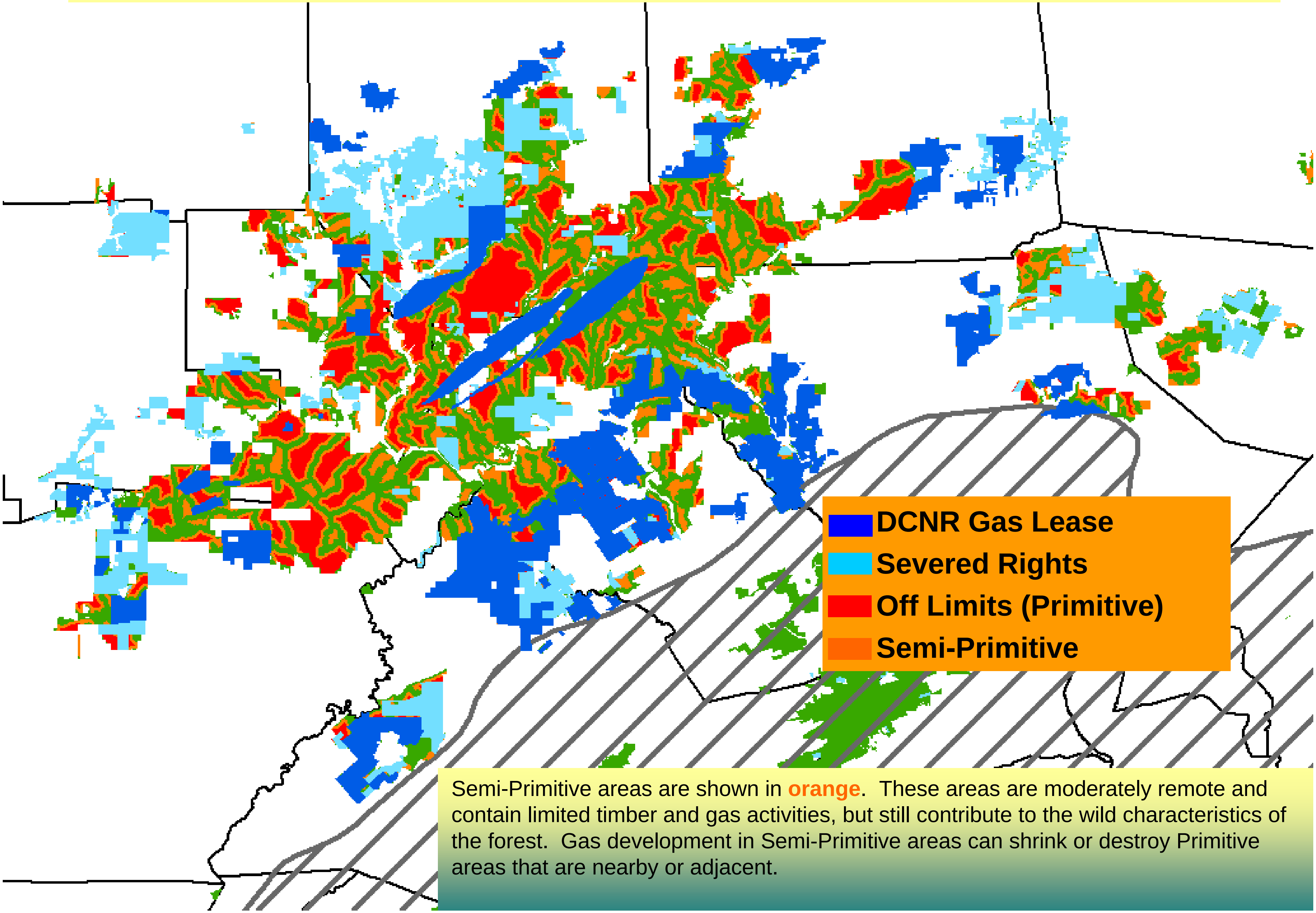
Much of the State Forest System has already been leased for Natural Gas (shown in **dark blue**). DCNR does not own mineral rights to approximately 15% of State Forest Land. These acres are unavailable for leasing and are shown in **light blue**. Although these areas are not available for leasing, they are subject to natural gas development by the private owners who own the subsurface rights.

Maintaining the Forest's Wild Character



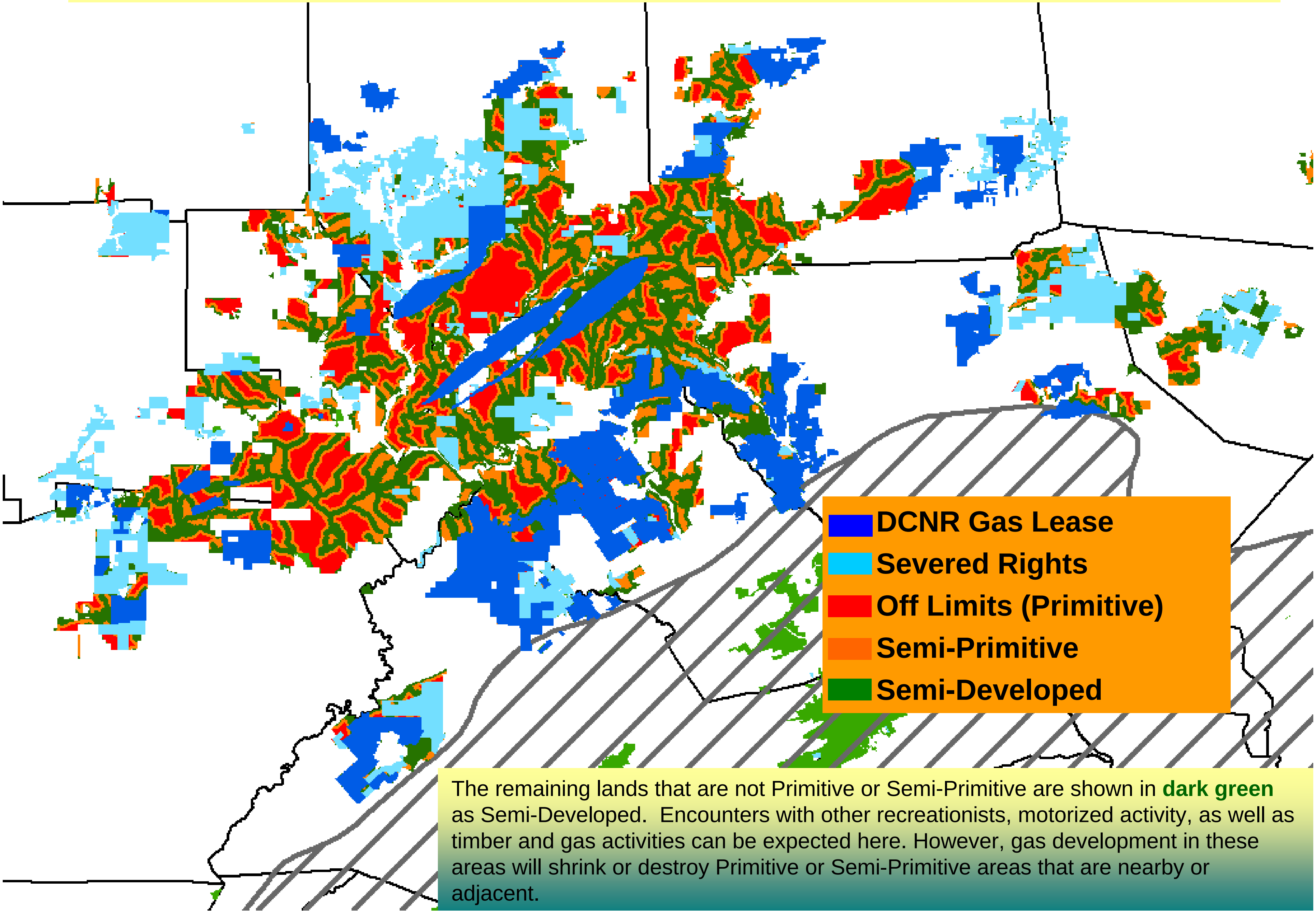
The most primitive and undeveloped areas of the State Forest are shown in **red** above. DCNR has designated these areas as off limits to drilling because they provide peace, solitude, remoteness, and backland experiences for recreation.

Maintaining the Forest's Wild Character



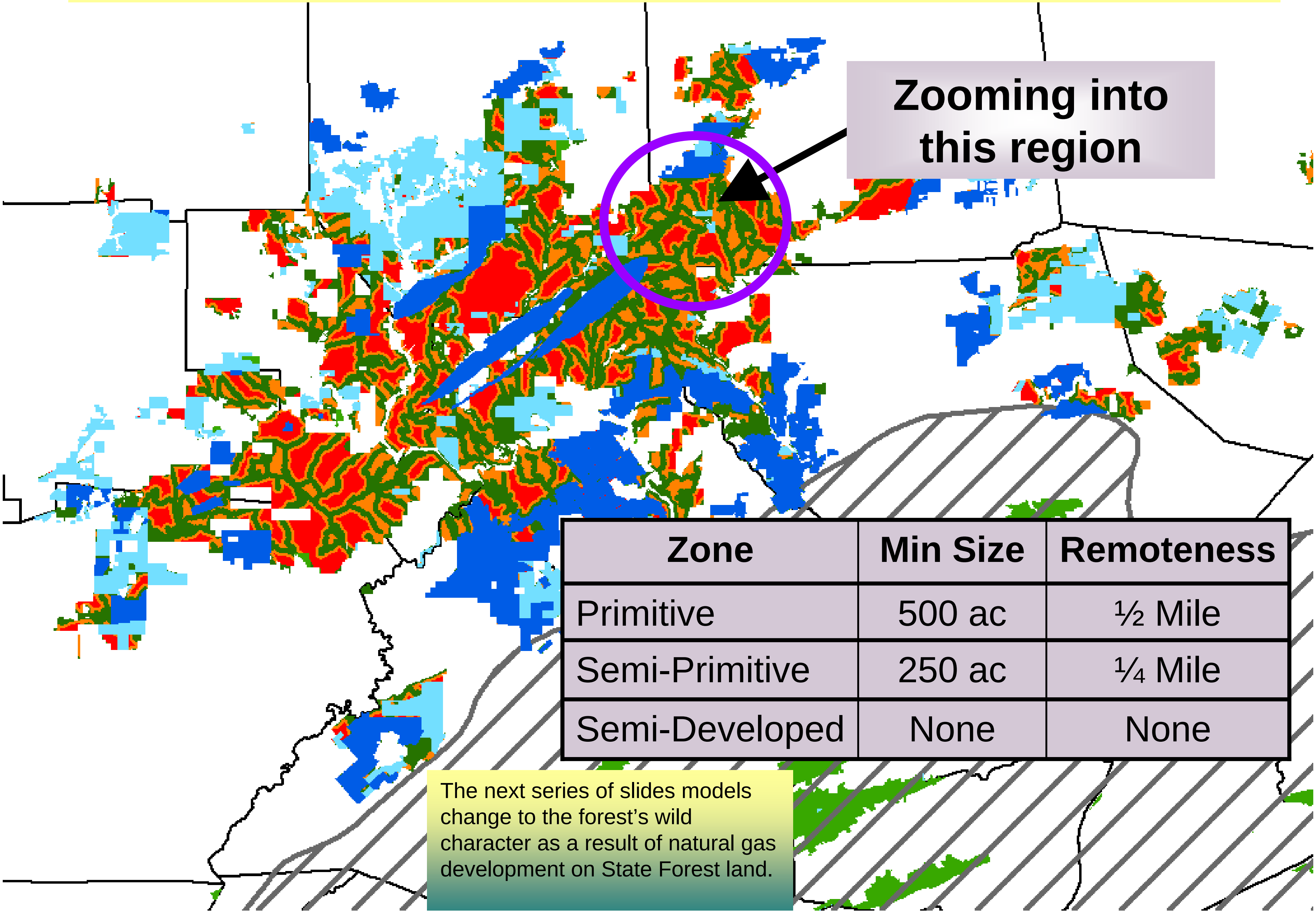
Semi-Primitive areas are shown in orange. These areas are moderately remote and contain limited timber and gas activities, but still contribute to the wild characteristics of the forest. Gas development in Semi-Primitive areas can shrink or destroy Primitive areas that are nearby or adjacent.

Maintaining the Forest's Wild Character



The remaining lands that are not Primitive or Semi-Primitive are shown in **dark green** as Semi-Developed. Encounters with other recreationists, motorized activity, as well as timber and gas activities can be expected here. However, gas development in these areas will shrink or destroy Primitive or Semi-Primitive areas that are nearby or adjacent.

Impacts on the Wild Character



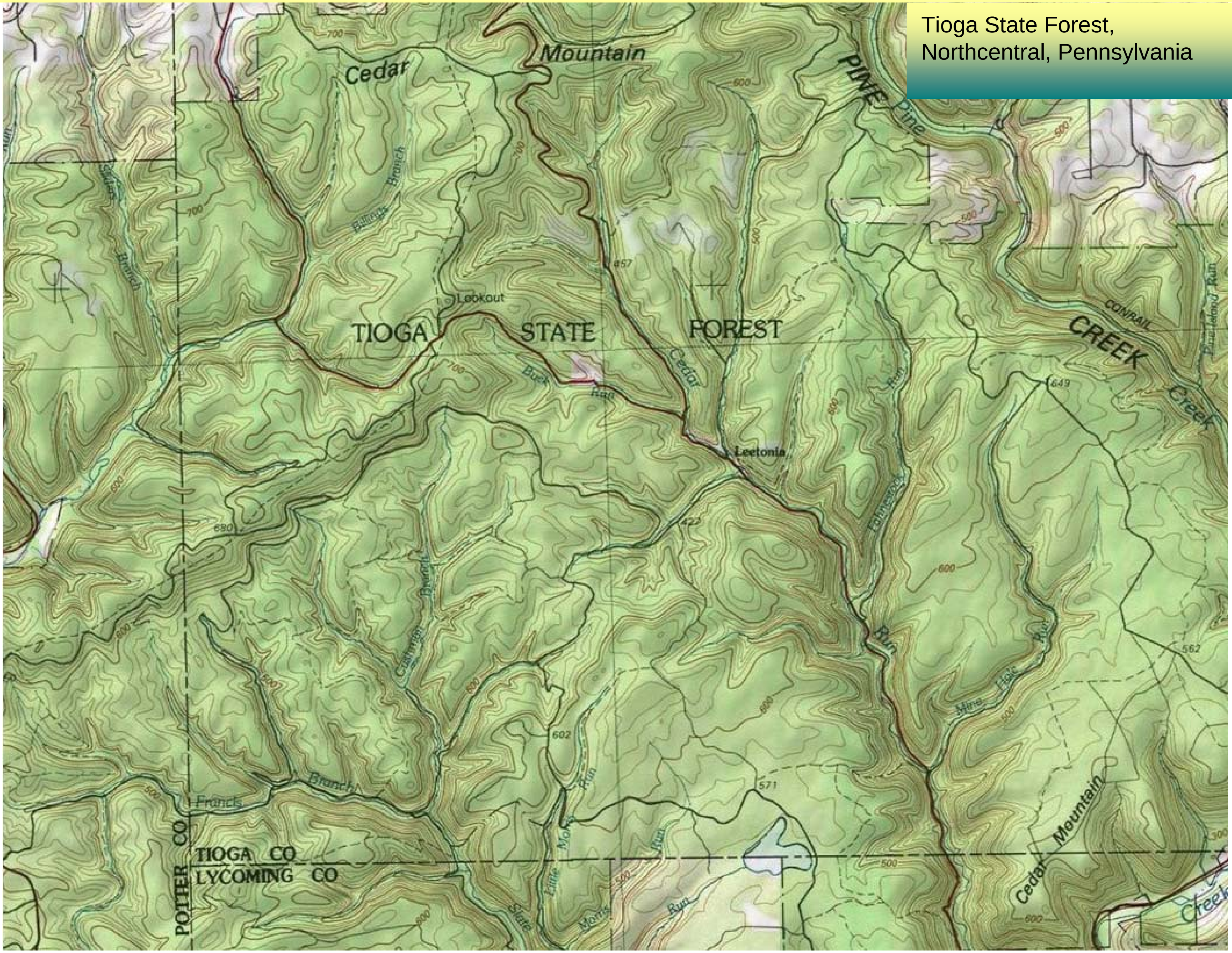
Zooming into this region

Zone	Min Size	Remoteness
Primitive	500 ac	½ Mile
Semi-Primitive	250 ac	¼ Mile
Semi-Developed	None	None

The next series of slides models change to the forest's wild character as a result of natural gas development on State Forest land.

Topography

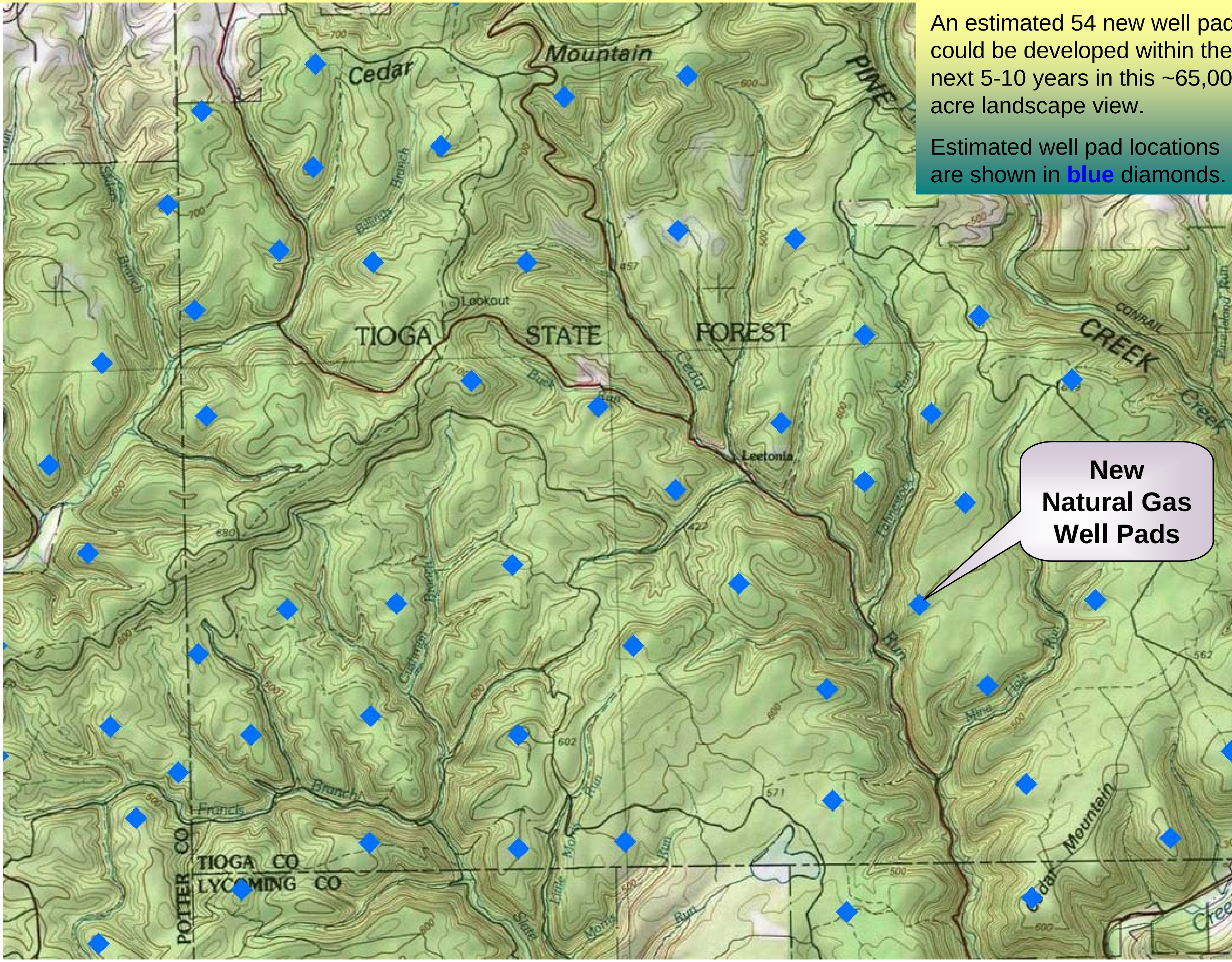
Tioga State Forest,
Northcentral, Pennsylvania



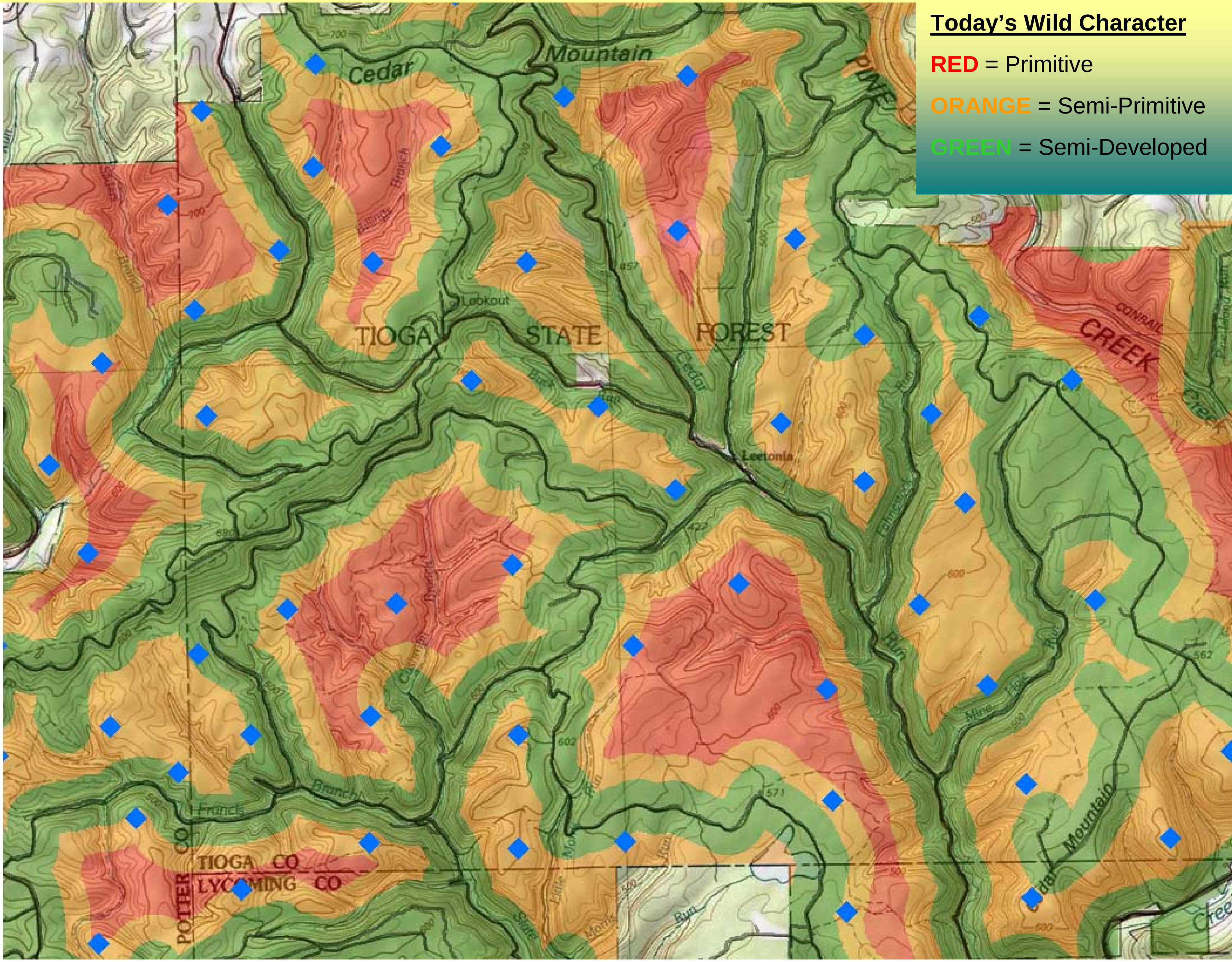
New Well Pad Locations

An estimated 54 new well pads could be developed within the next 5-10 years in this ~65,000 acre landscape view.

Estimated well pad locations are shown in **blue** diamonds.



Wild Character before Well Pads



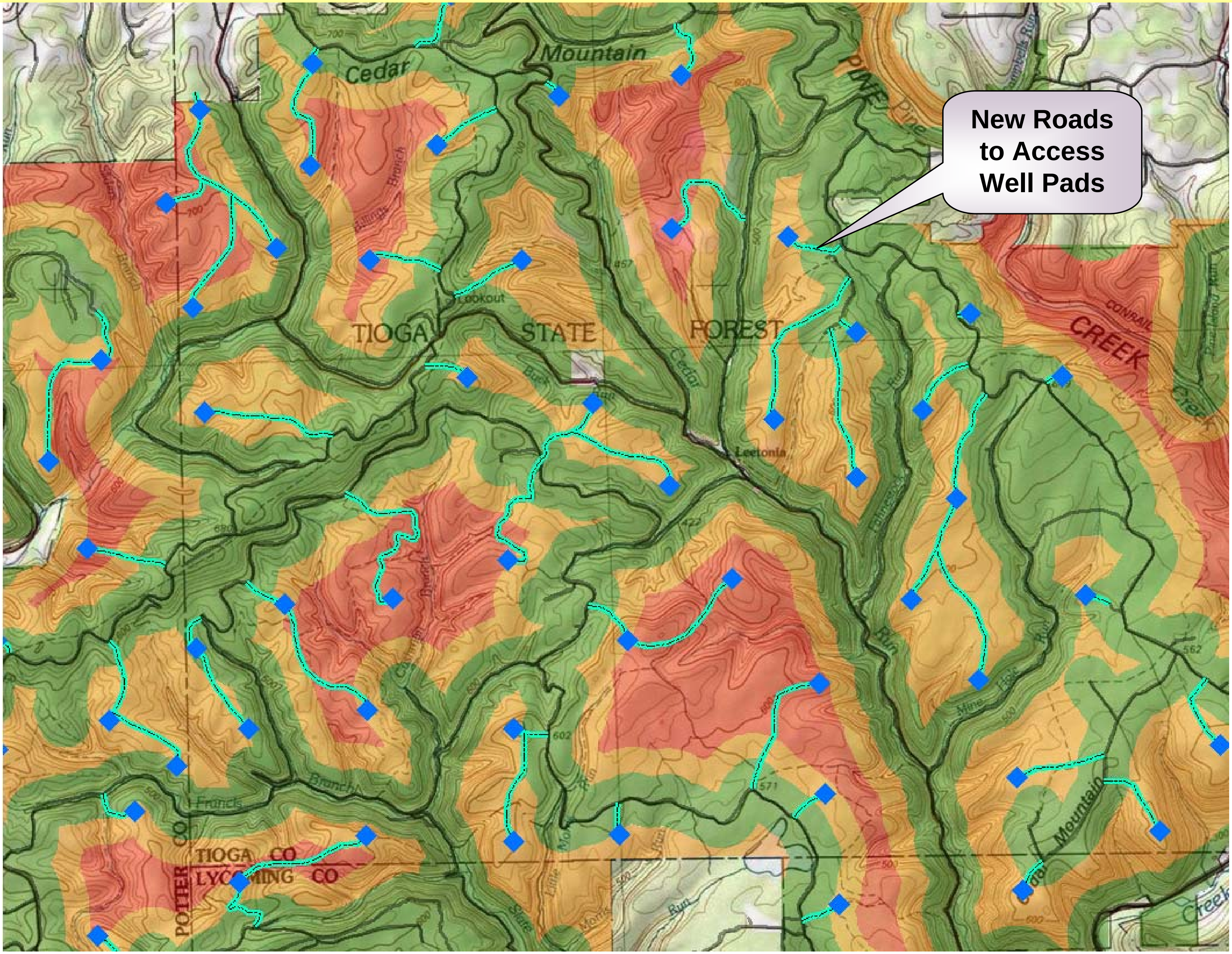
Today's Wild Character

RED = Primitive

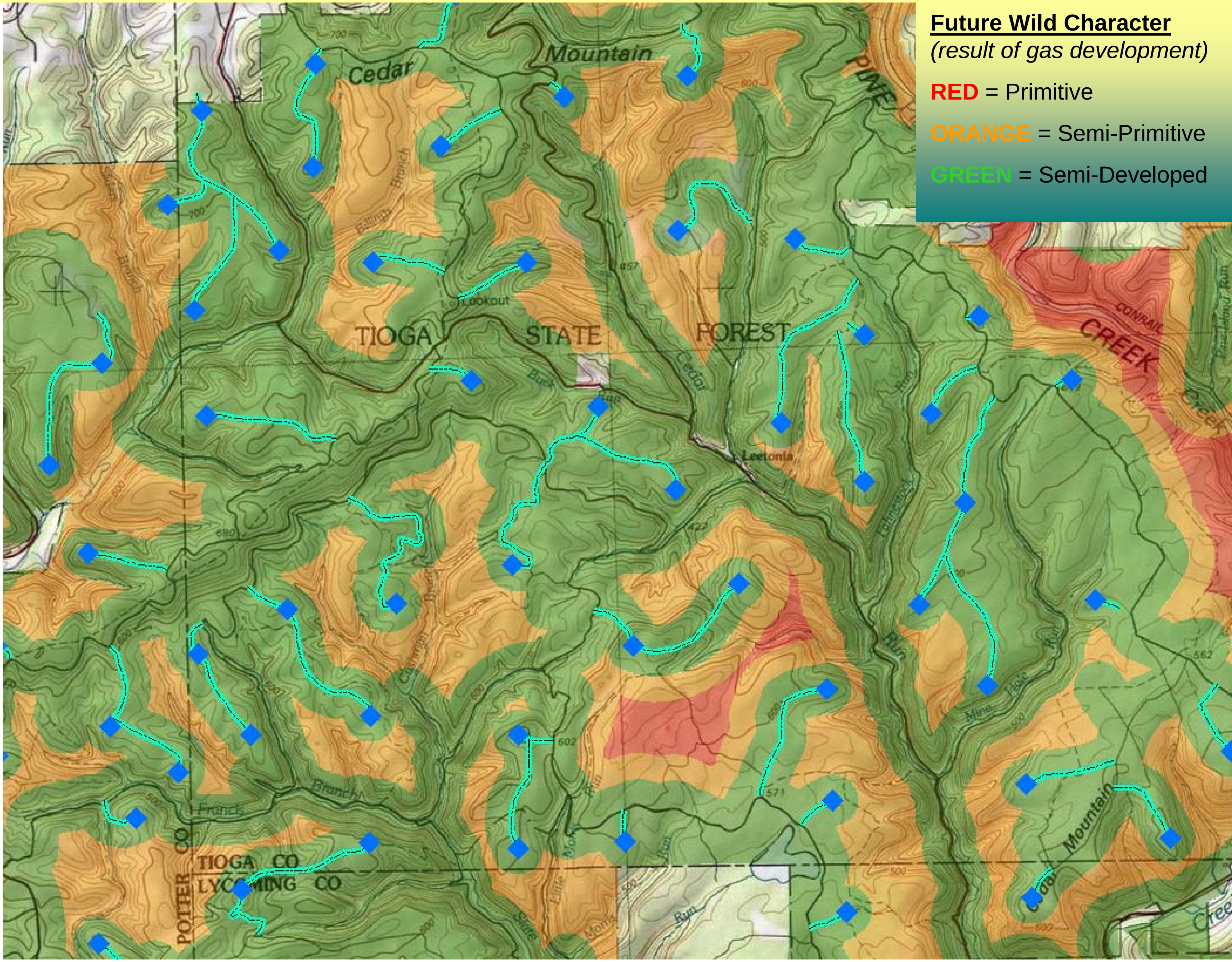
ORANGE = Semi-Primitive

GREEN = Semi-Developed

New Access Roads Required



Forest’s Wild Character with New Well Pads



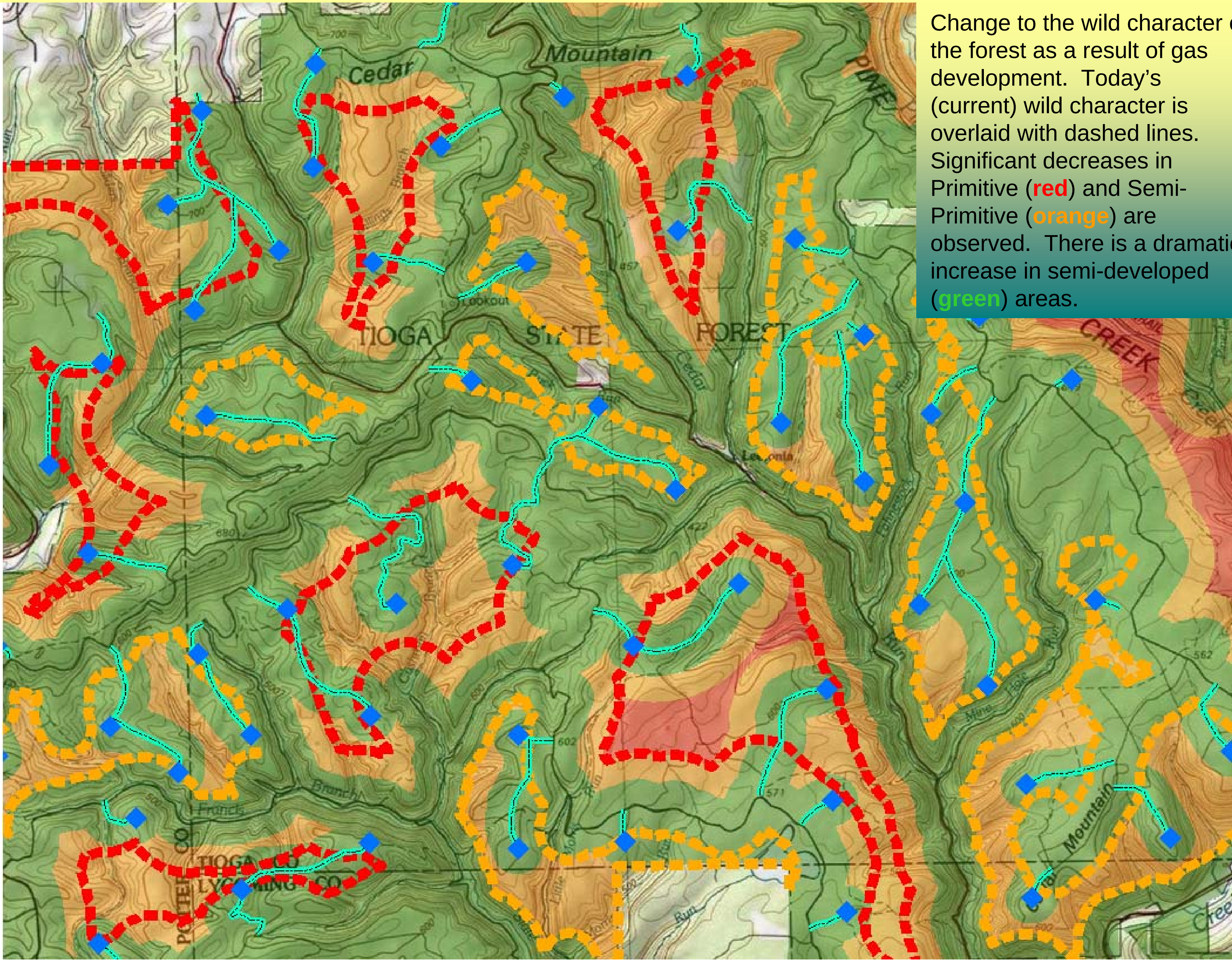
<u>**Future Wild Character**</u>
(result of gas development)

RED = Primitive

ORANGE = Semi-Primitive

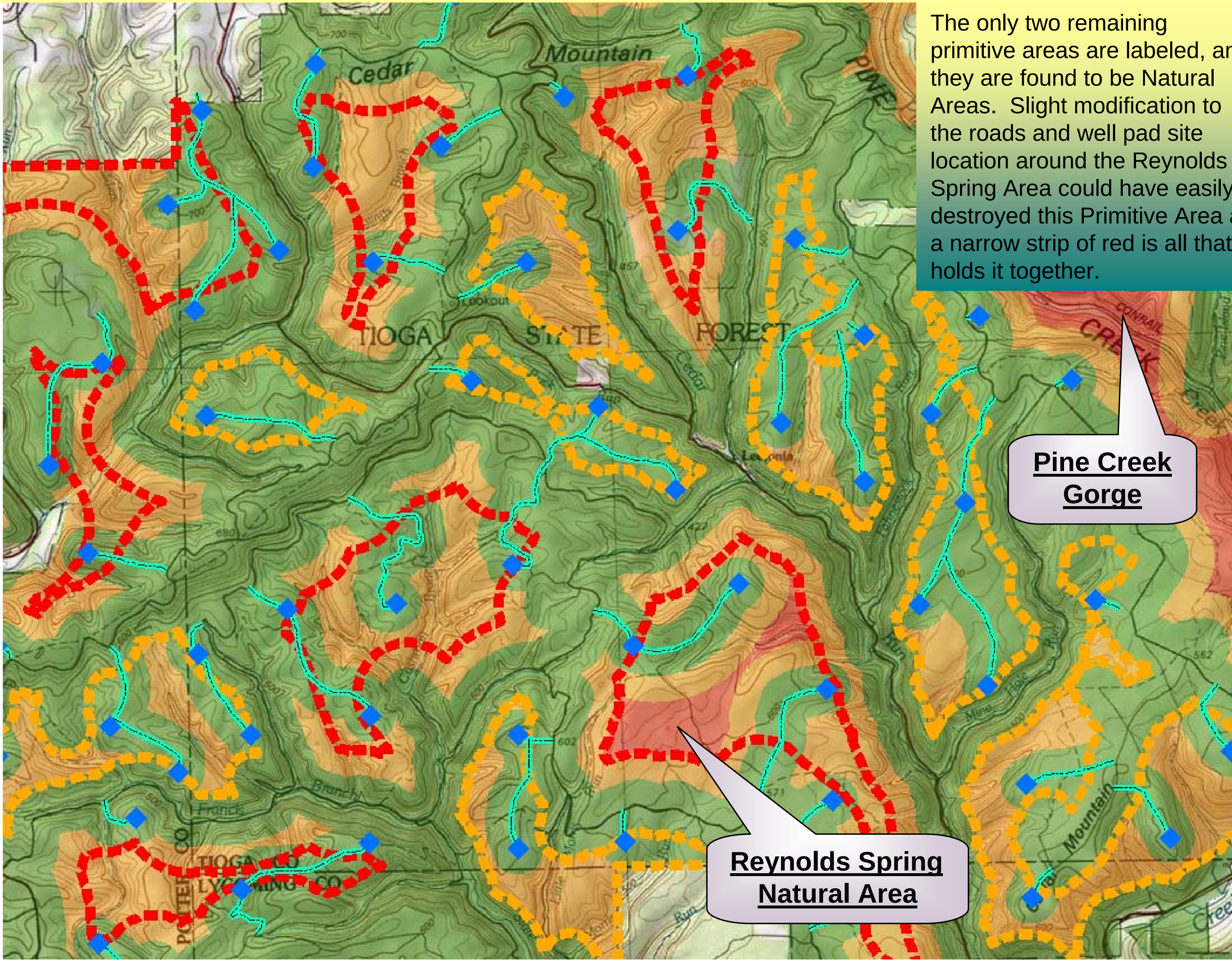
GREEN = Semi-Developed

Impact on the Forest's Wild Character



Change to the wild character of the forest as a result of gas development. Today's (current) wild character is overlaid with dashed lines. Significant decreases in Primitive (**red**) and Semi-Primitive (**orange**) are observed. There is a dramatic increase in semi-developed (**green**) areas.

Impact on the Forest's Wild Character

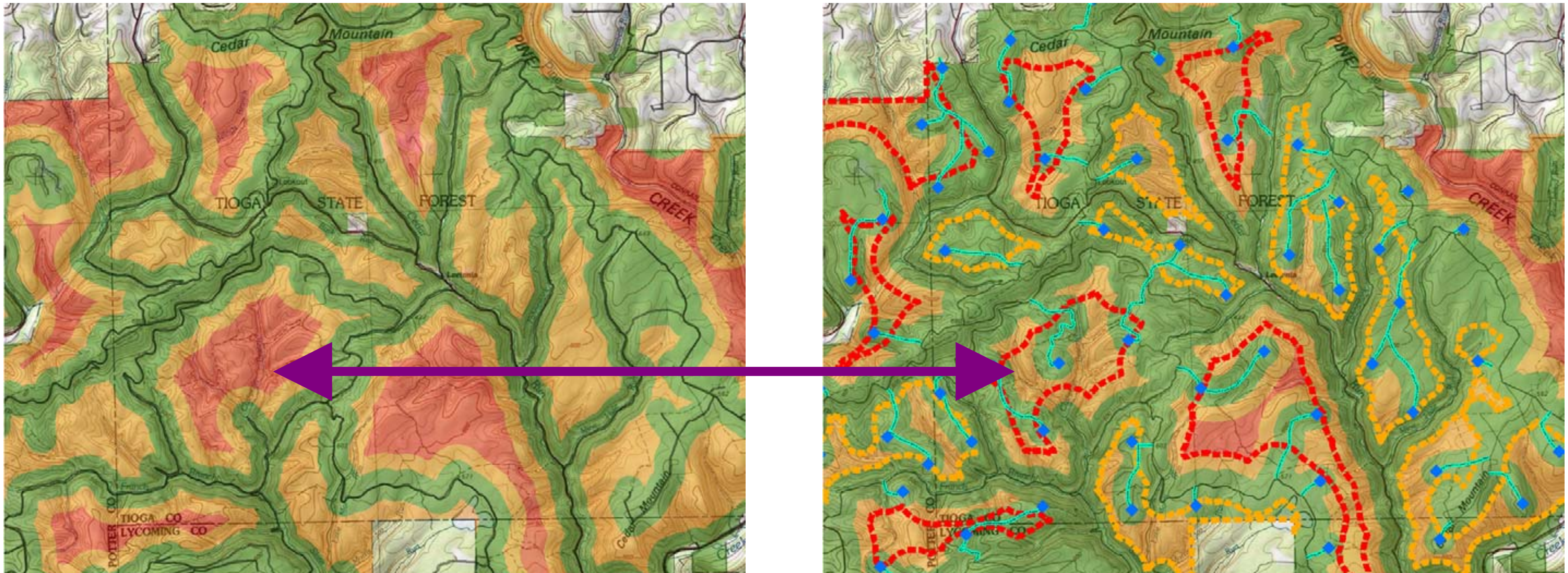


The only two remaining primitive areas are labeled, and they are found to be Natural Areas. Slight modification to the roads and well pad site location around the Reynolds Spring Area could have easily destroyed this Primitive Area as a narrow strip of red is all that holds it together.

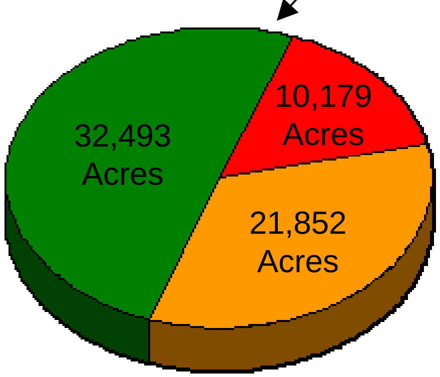
Change in the Forest's Wild Character

Before

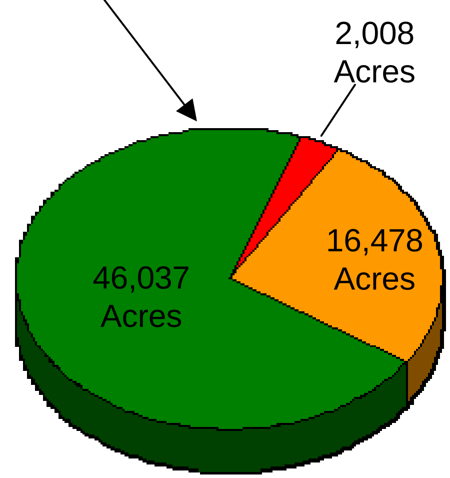
After



In this ~65,000 acre landscape view, with 54 new well pads…

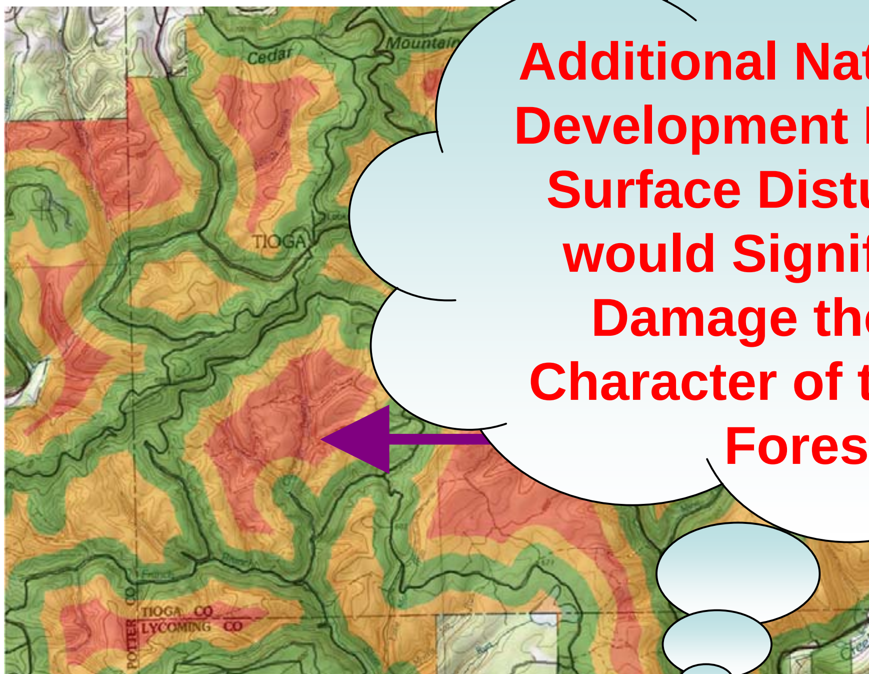


Zone	Net Gain/Loss
Primitive	-8,171
Semi-Primitive	-5,374
Semi-Developed	13,545

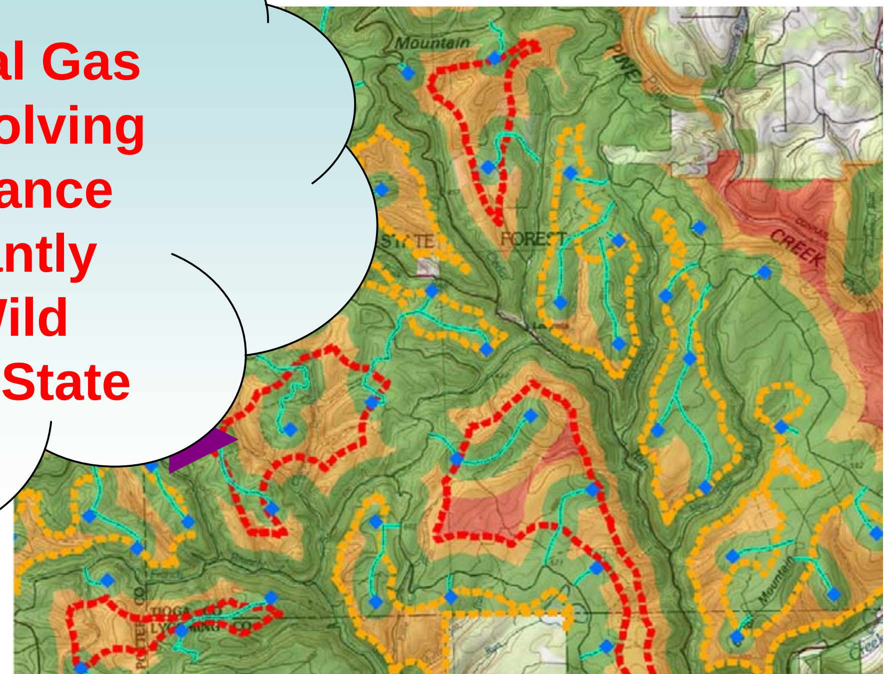


Modeling Change in the Forest's Wild Character

Before

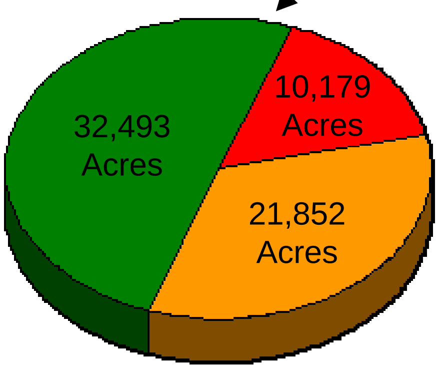


After



Additional Natural Gas Development Involving Surface Disturbance would Significantly Damage the Wild Character of the State Forest

In this ~65,000 acre landscape view, with 54 new well pads…



Zone	Net Gain/Loss
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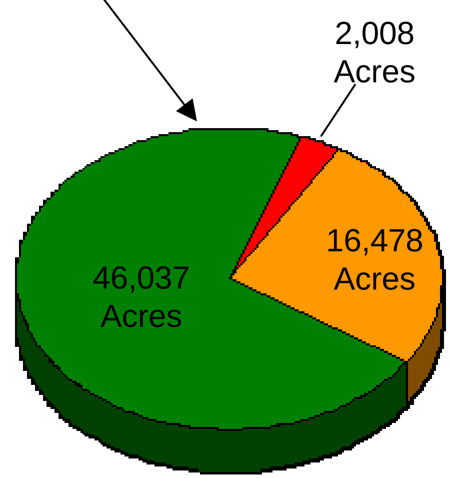
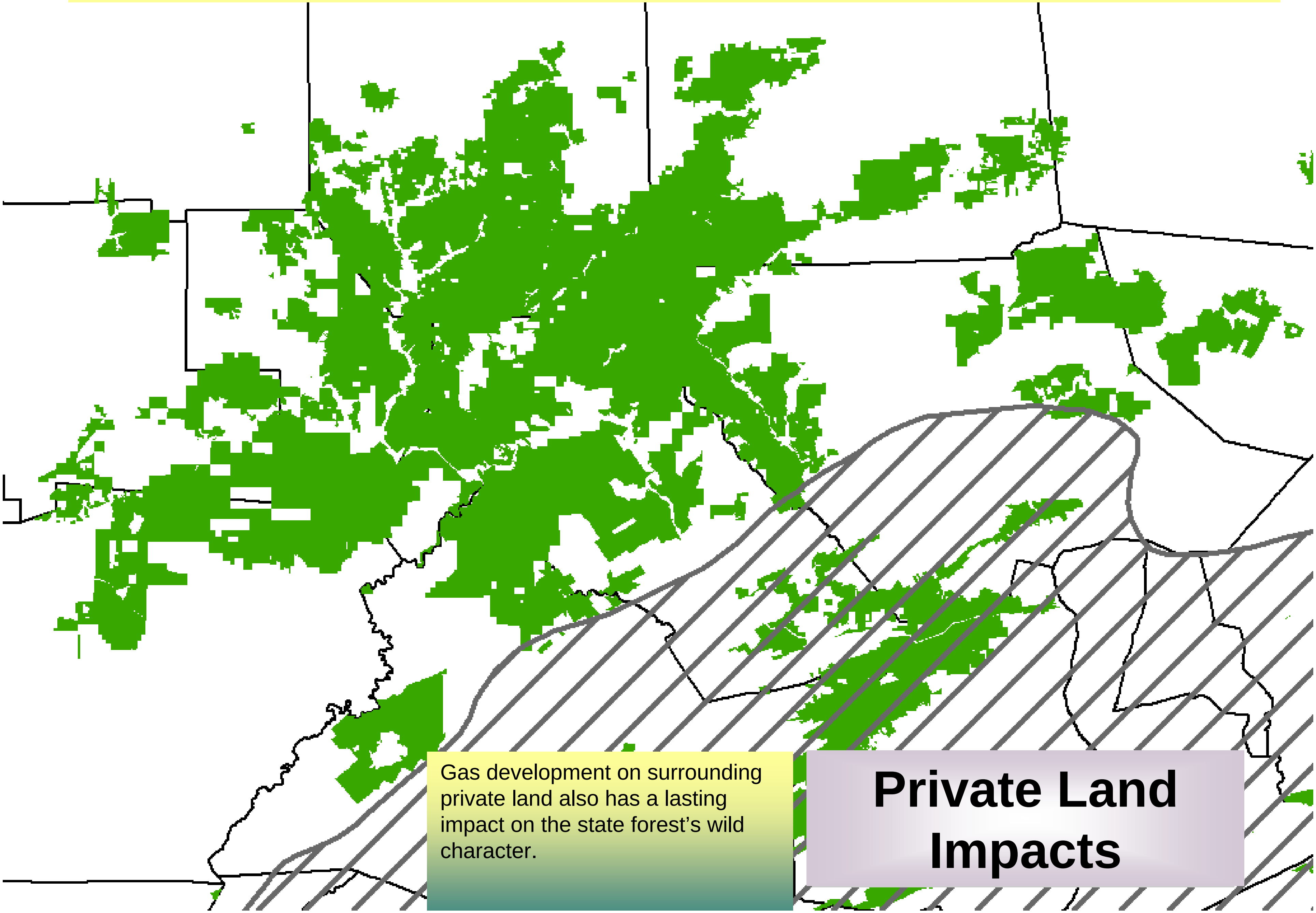


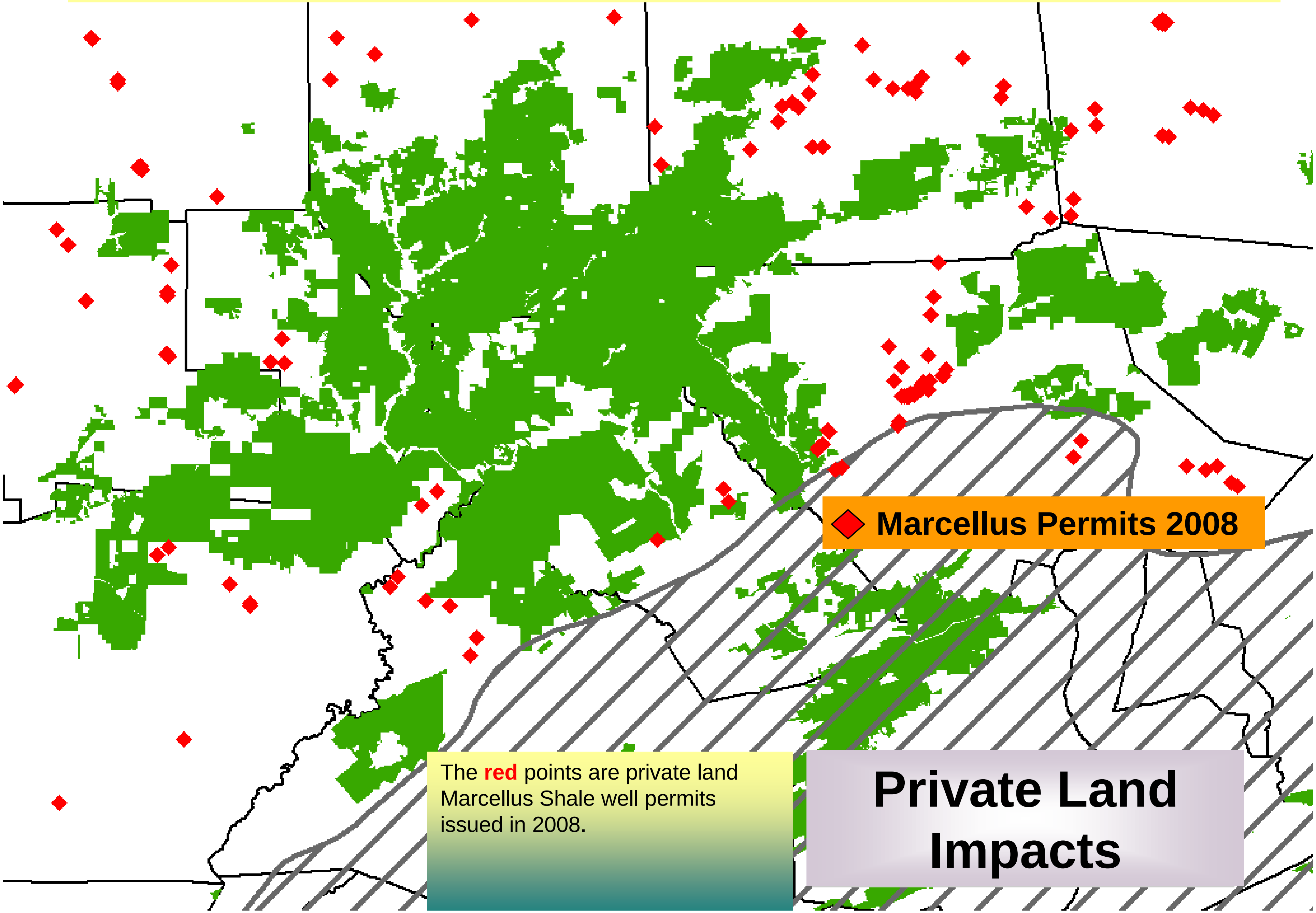
Maintaining the Forest's Wild Character



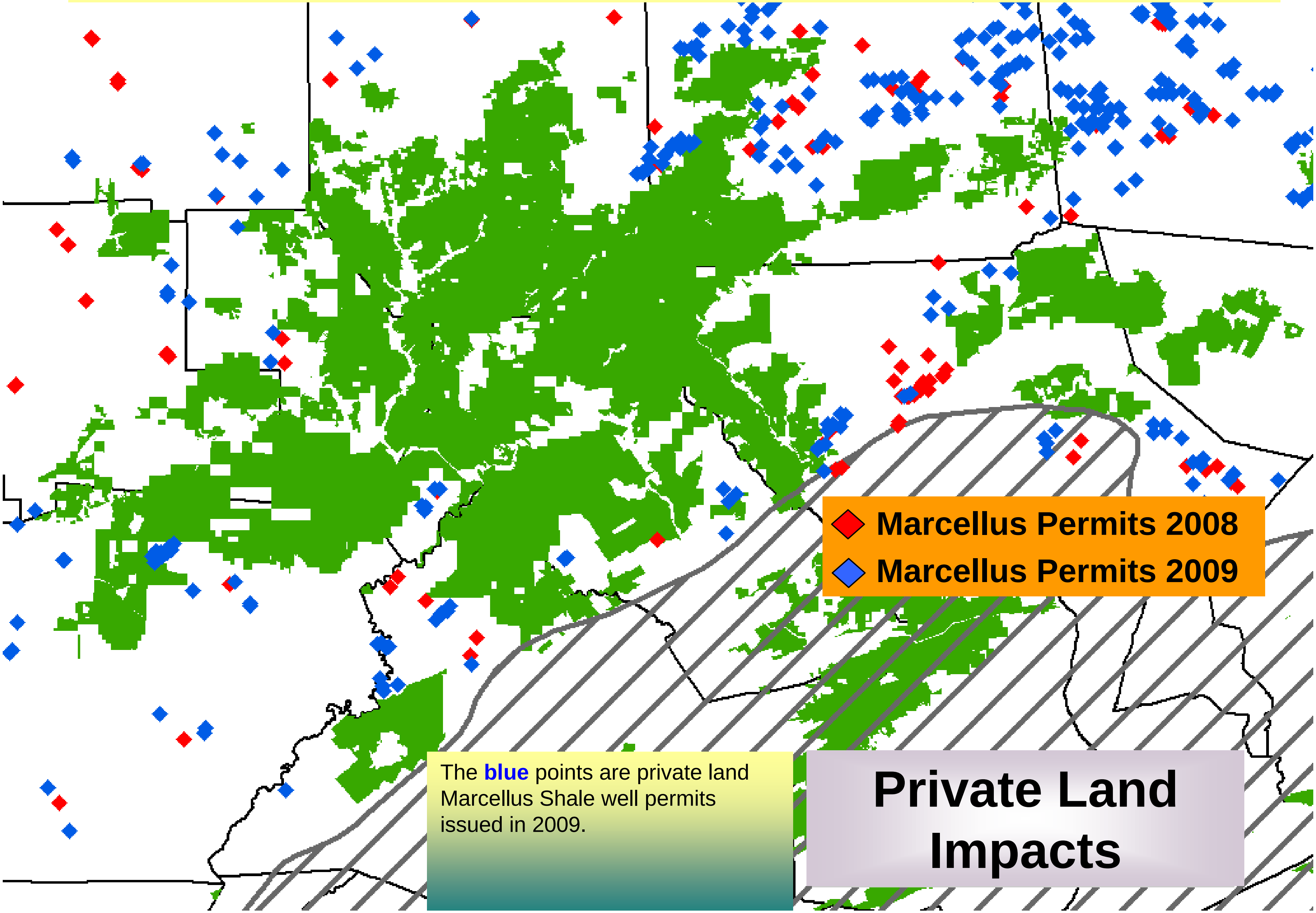
Gas development on surrounding private land also has a lasting impact on the state forest's wild character.

Private Land Impacts

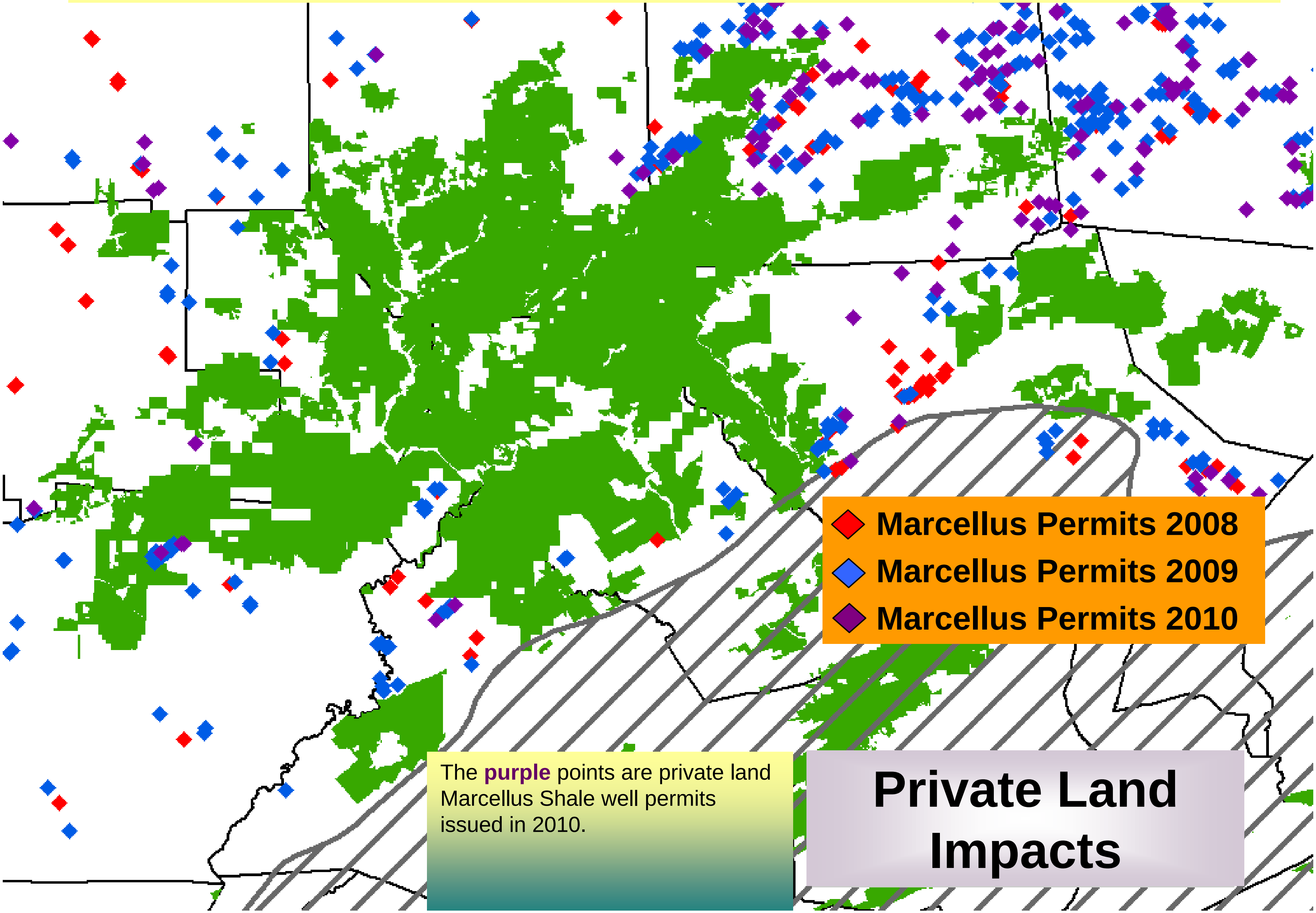
Maintaining the Forest's Wild Character



Maintaining the Forest's Wild Character



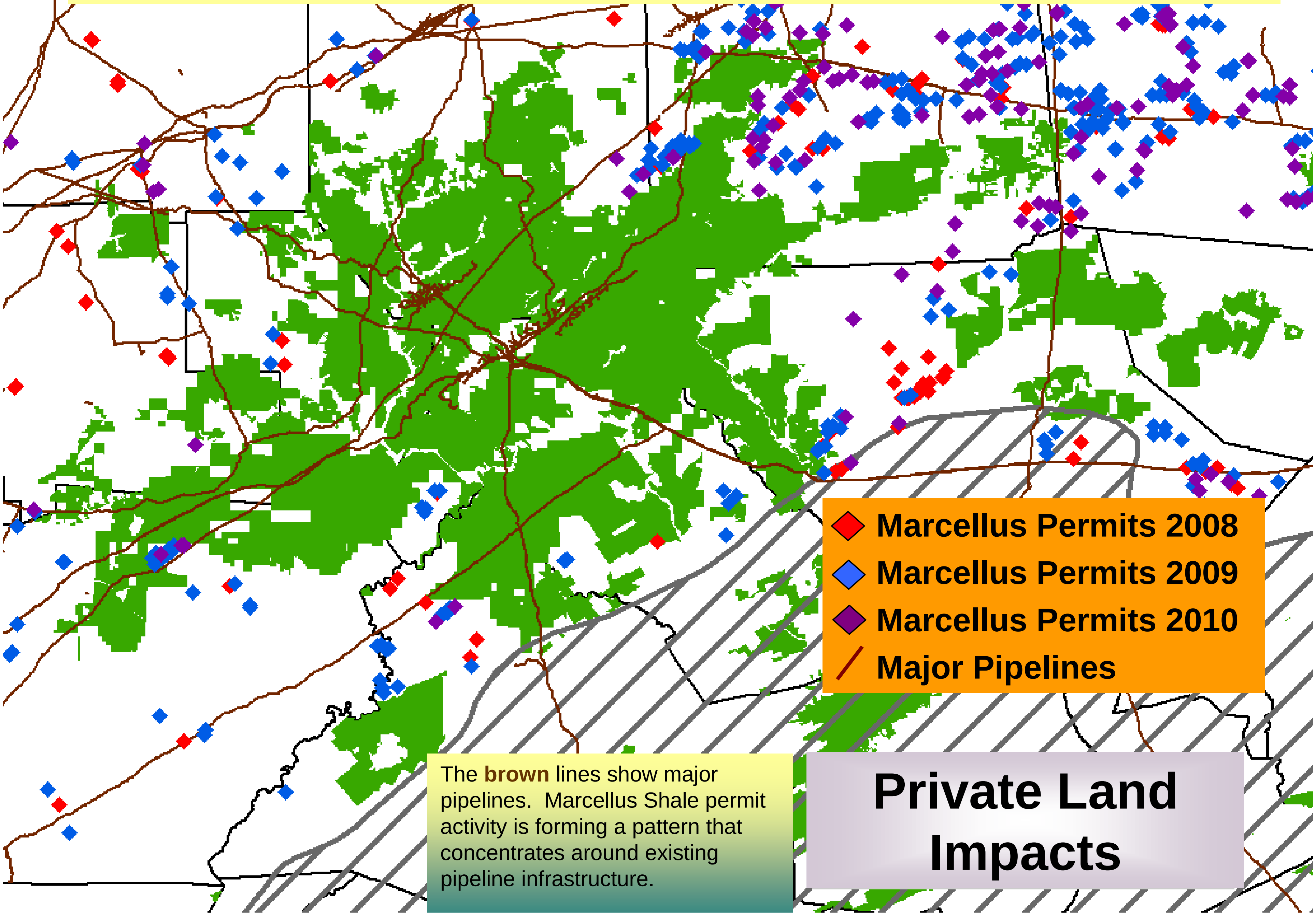
Maintaining the Forest's Wild Character



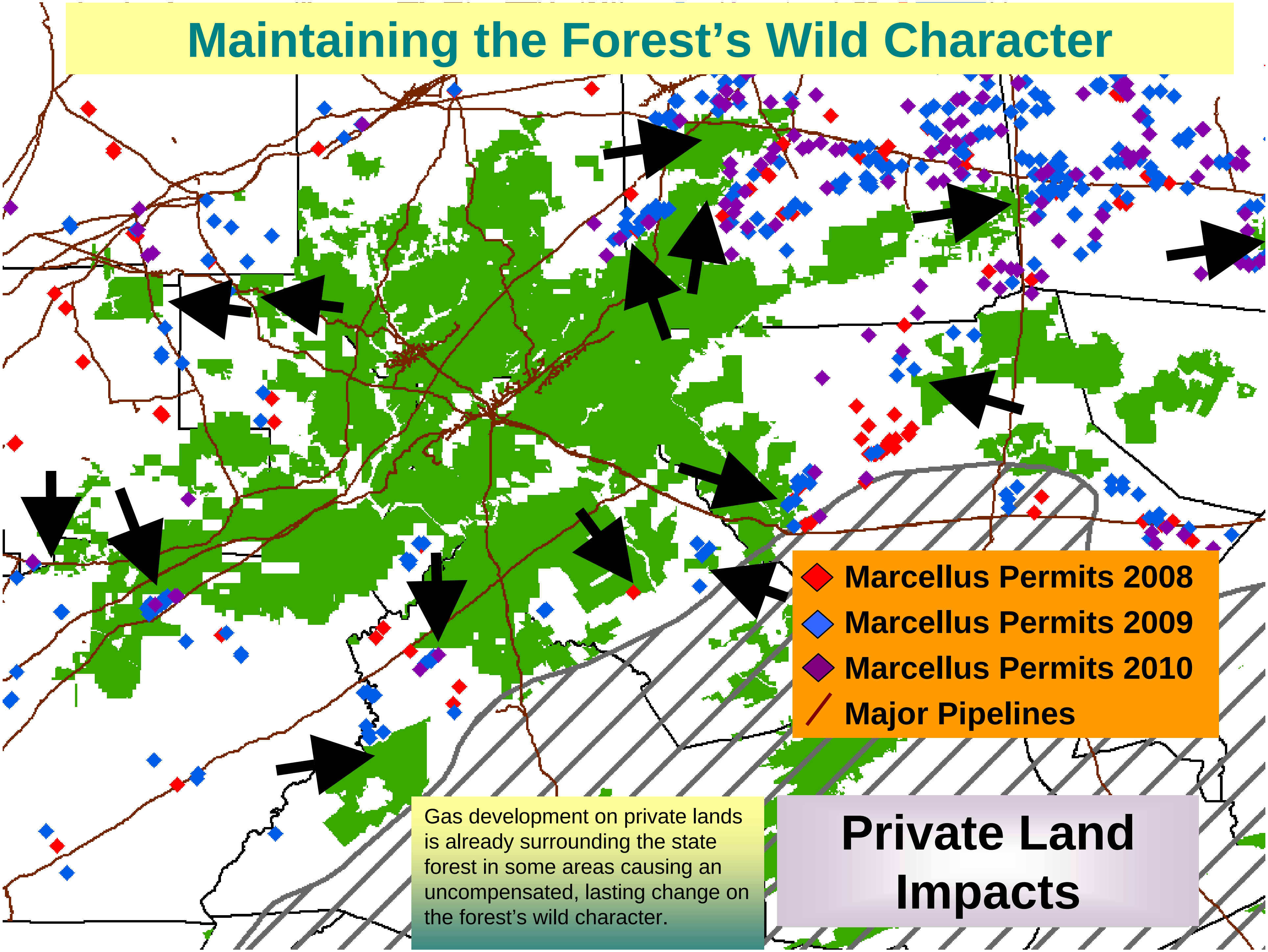
The **purple** points are private land Marcellus Shale well permits issued in 2010.

Private Land Impacts

Maintaining the Forest's Wild Character



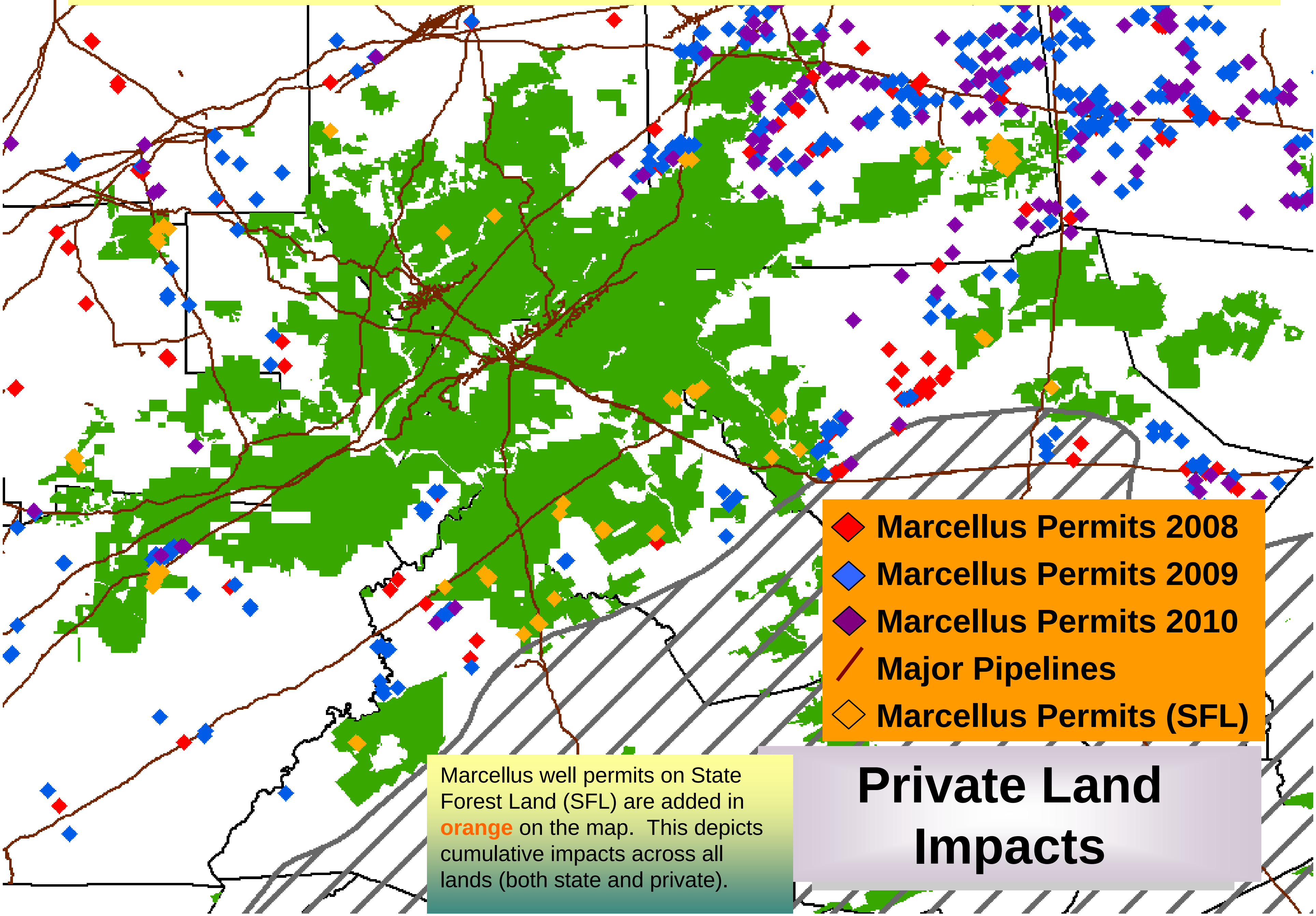
Maintaining the Forest's Wild Character



Gas development on private lands is already surrounding the state forest in some areas causing an uncompensated, lasting change on the forest's wild character.

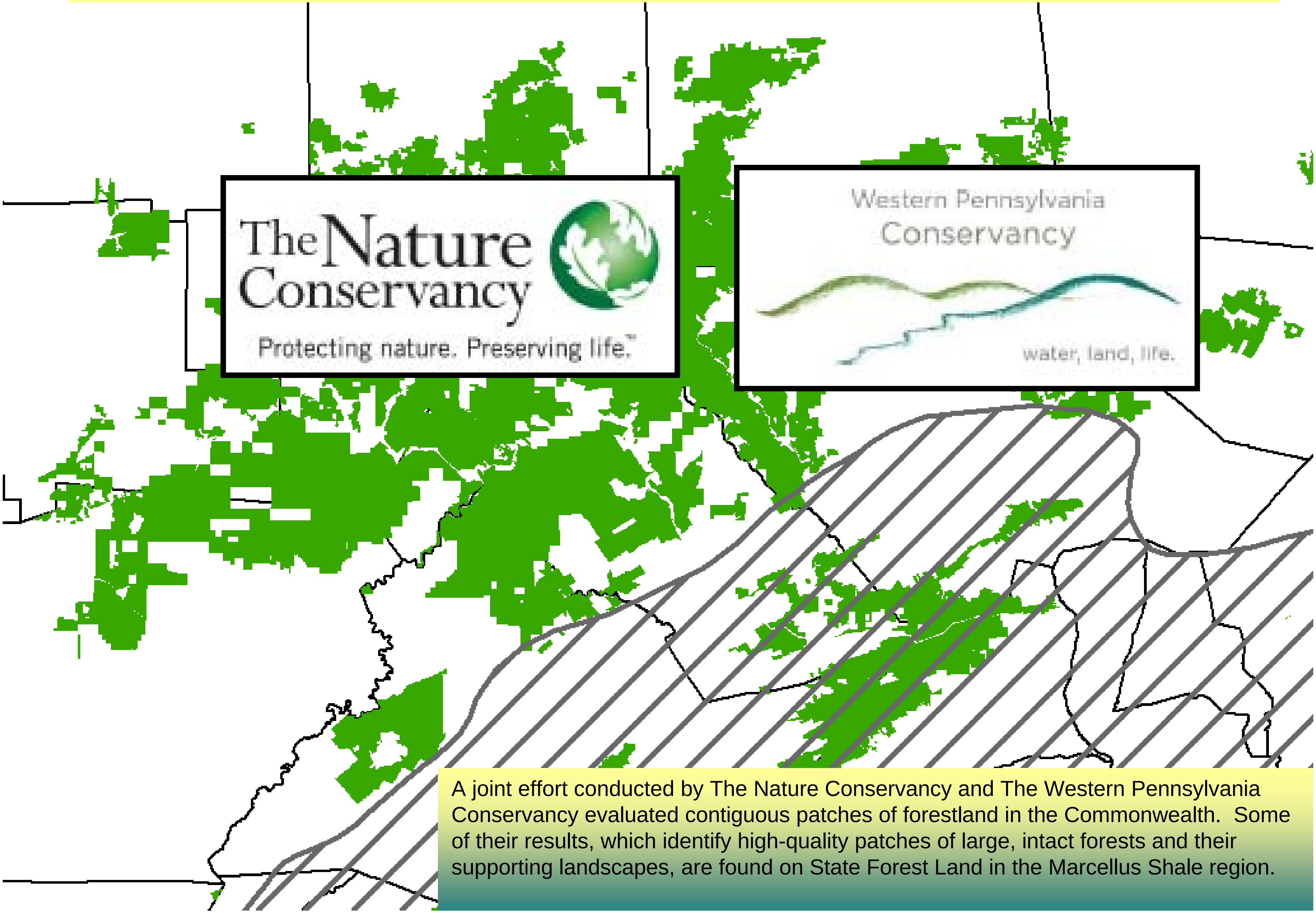
Private Land Impacts

Maintaining the Forest's Wild Character



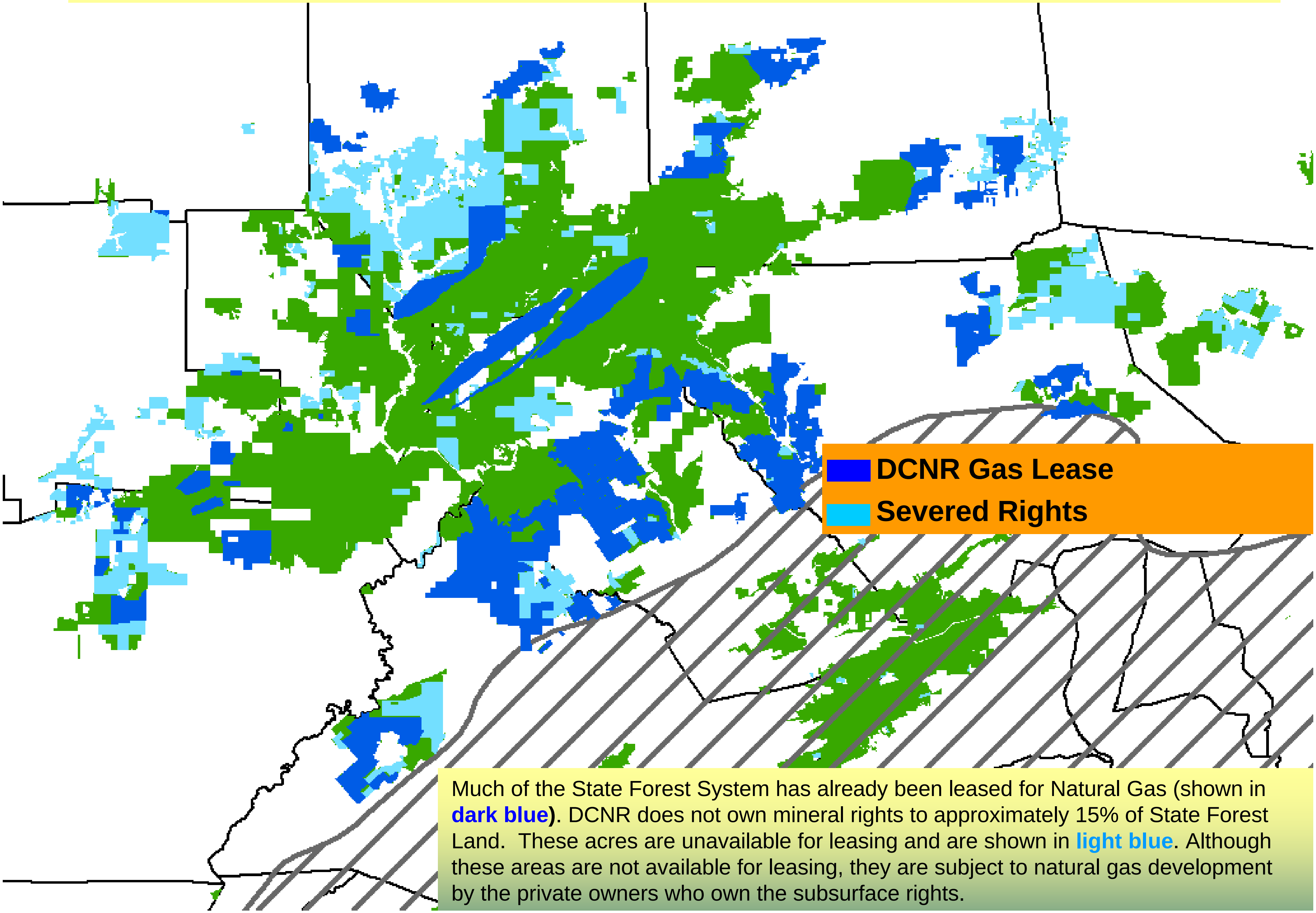
Marcellus well permits on State Forest Land (SFL) are added in **orange** on the map. This depicts cumulative impacts across all lands (both state and private).

TNC-WPC Priority Forest Patches



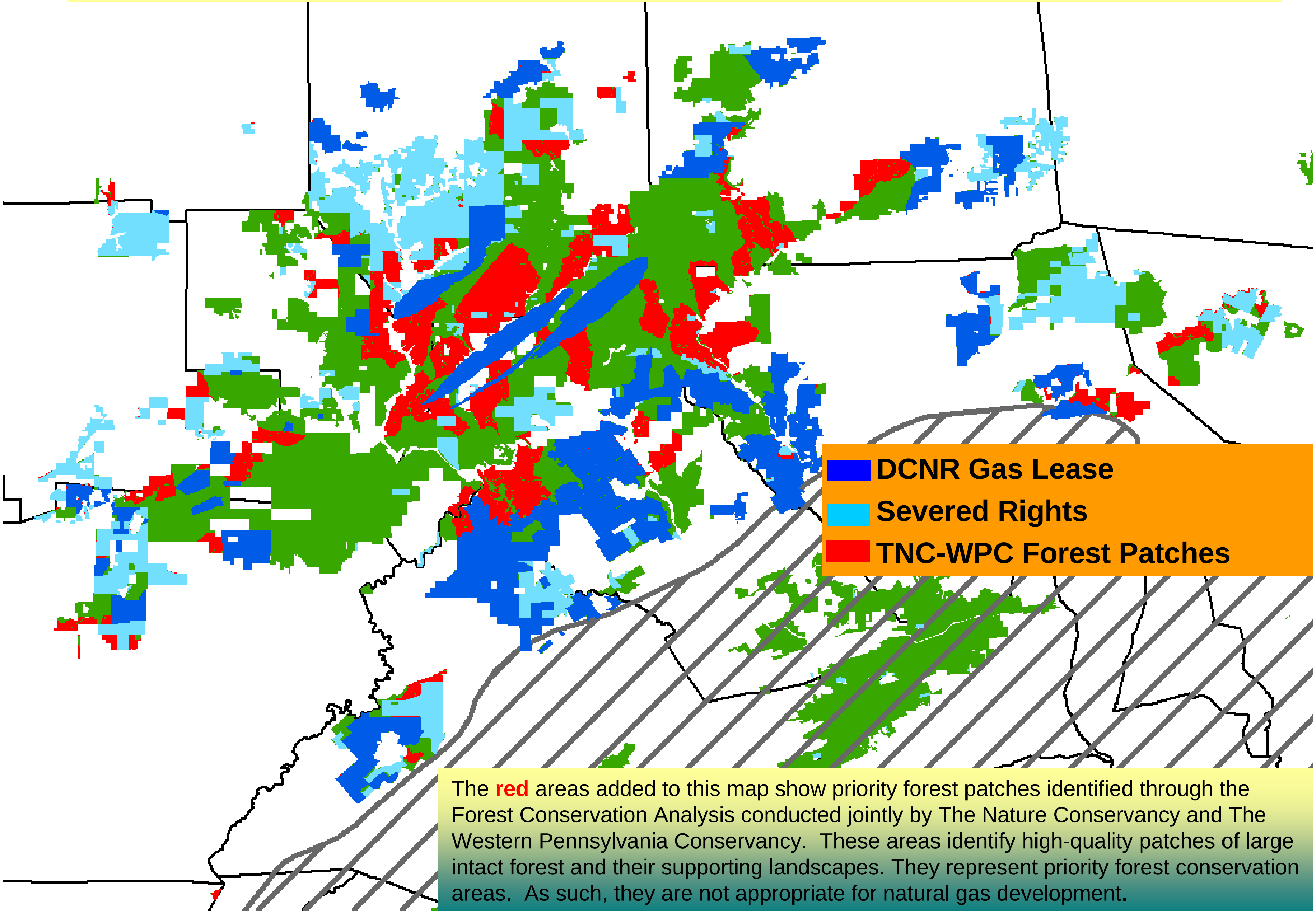
A joint effort conducted by The Nature Conservancy and The Western Pennsylvania Conservancy evaluated contiguous patches of forestland in the Commonwealth. Some of their results, which identify high-quality patches of large, intact forests and their supporting landscapes, are found on State Forest Land in the Marcellus Shale region.

TNC-WPC Priority Forest Patches



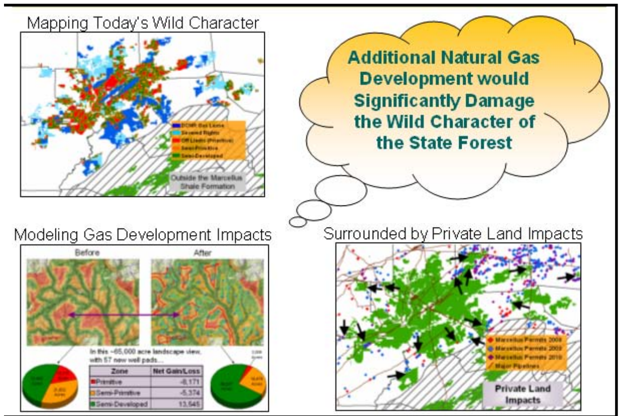
Much of the State Forest System has already been leased for Natural Gas (shown in **dark blue**). DCNR does not own mineral rights to approximately 15% of State Forest Land. These acres are unavailable for leasing and are shown in **light blue**. Although these areas are not available for leasing, they are subject to natural gas development by the private owners who own the subsurface rights.

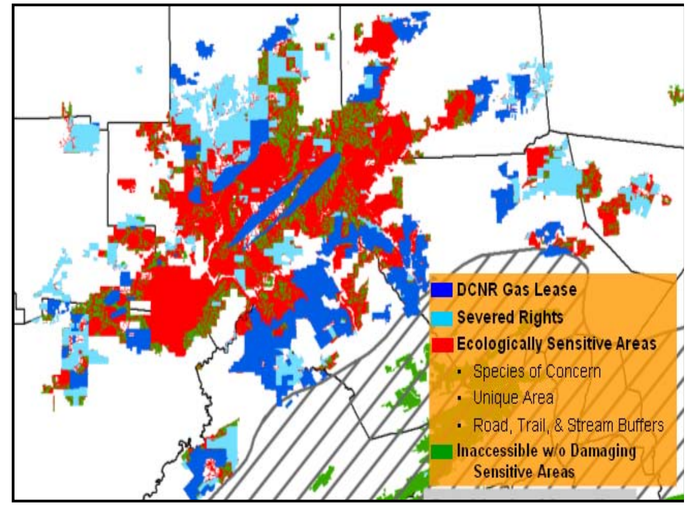
TNC-WPC Priority Forest Patches



The **red** areas added to this map show priority forest patches identified through the Forest Conservation Analysis conducted jointly by The Nature Conservancy and The Western Pennsylvania Conservancy. These areas identify high-quality patches of large intact forest and their supporting landscapes. They represent priority forest conservation areas. As such, they are not appropriate for natural gas development.

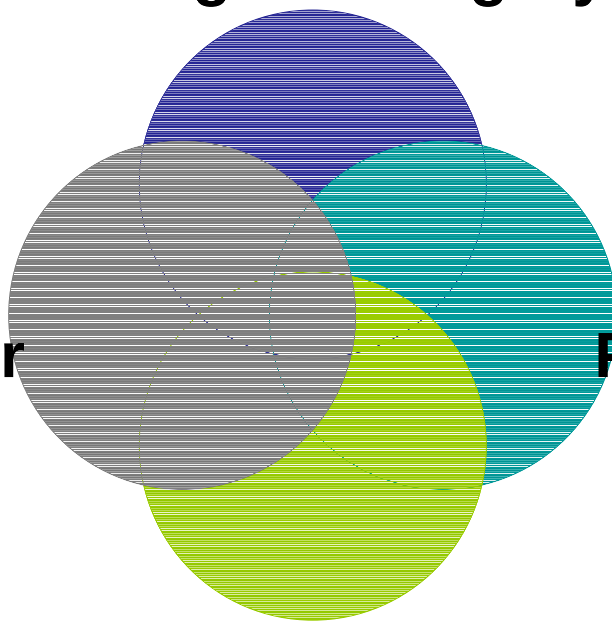
Cumulative Assessment & Impacts





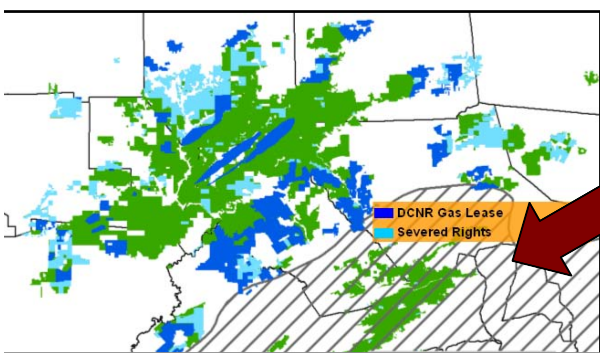
The Forest's Ecological Integrity

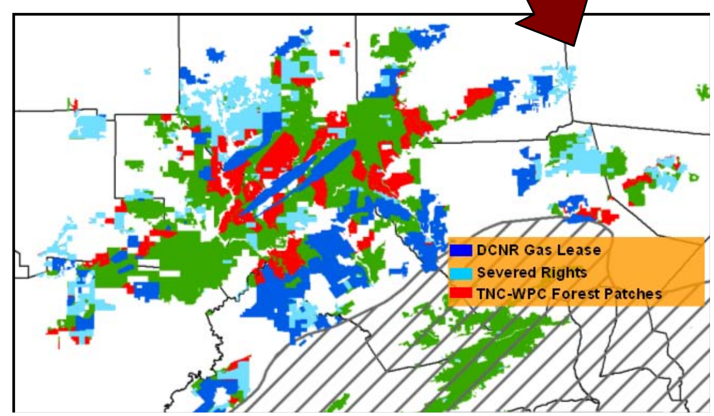
The Forest's Wild Character



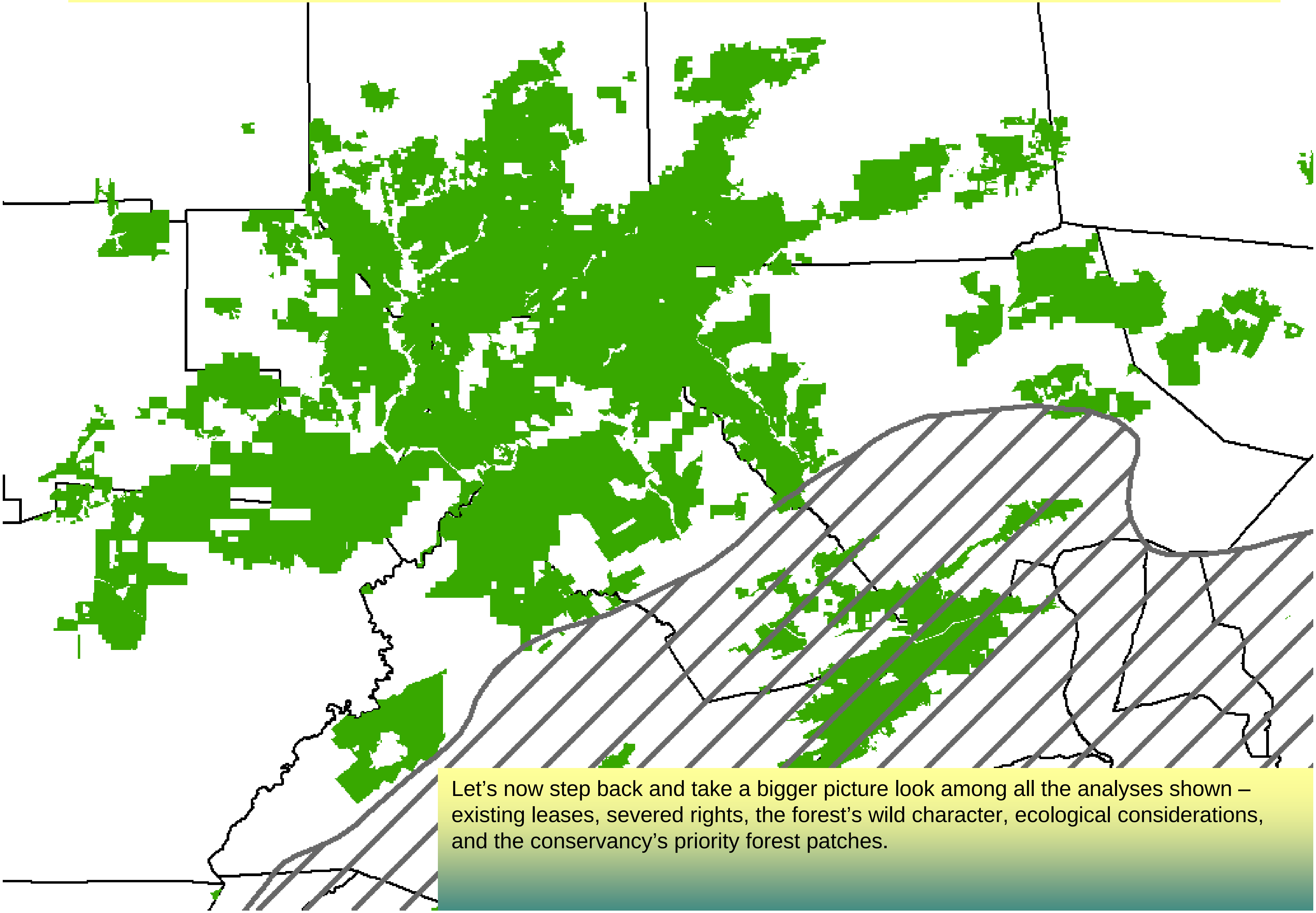
TNC-WPC Forest Patches

Existing Leases & Severed Rights



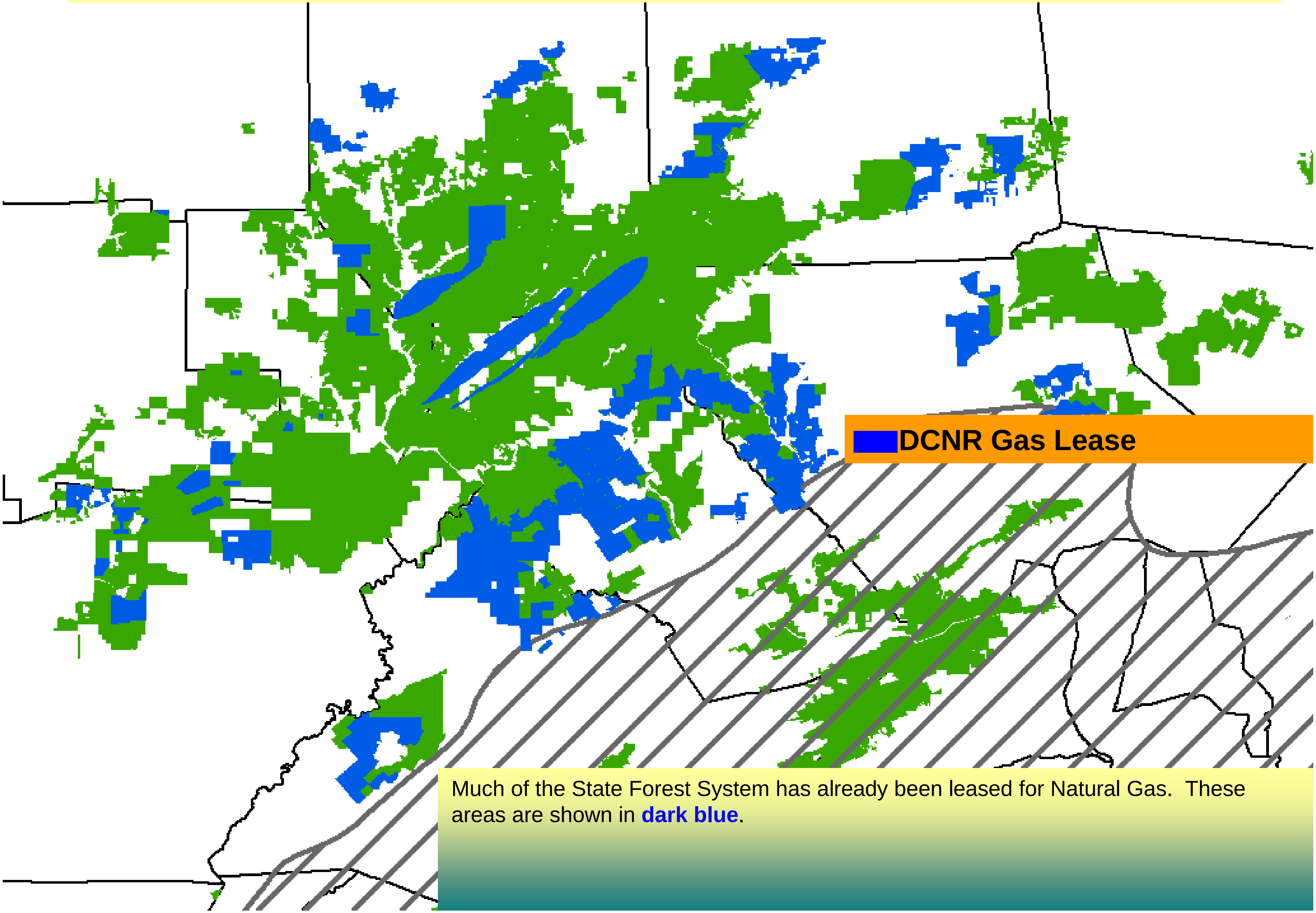


Cumulative Assessment & Impacts



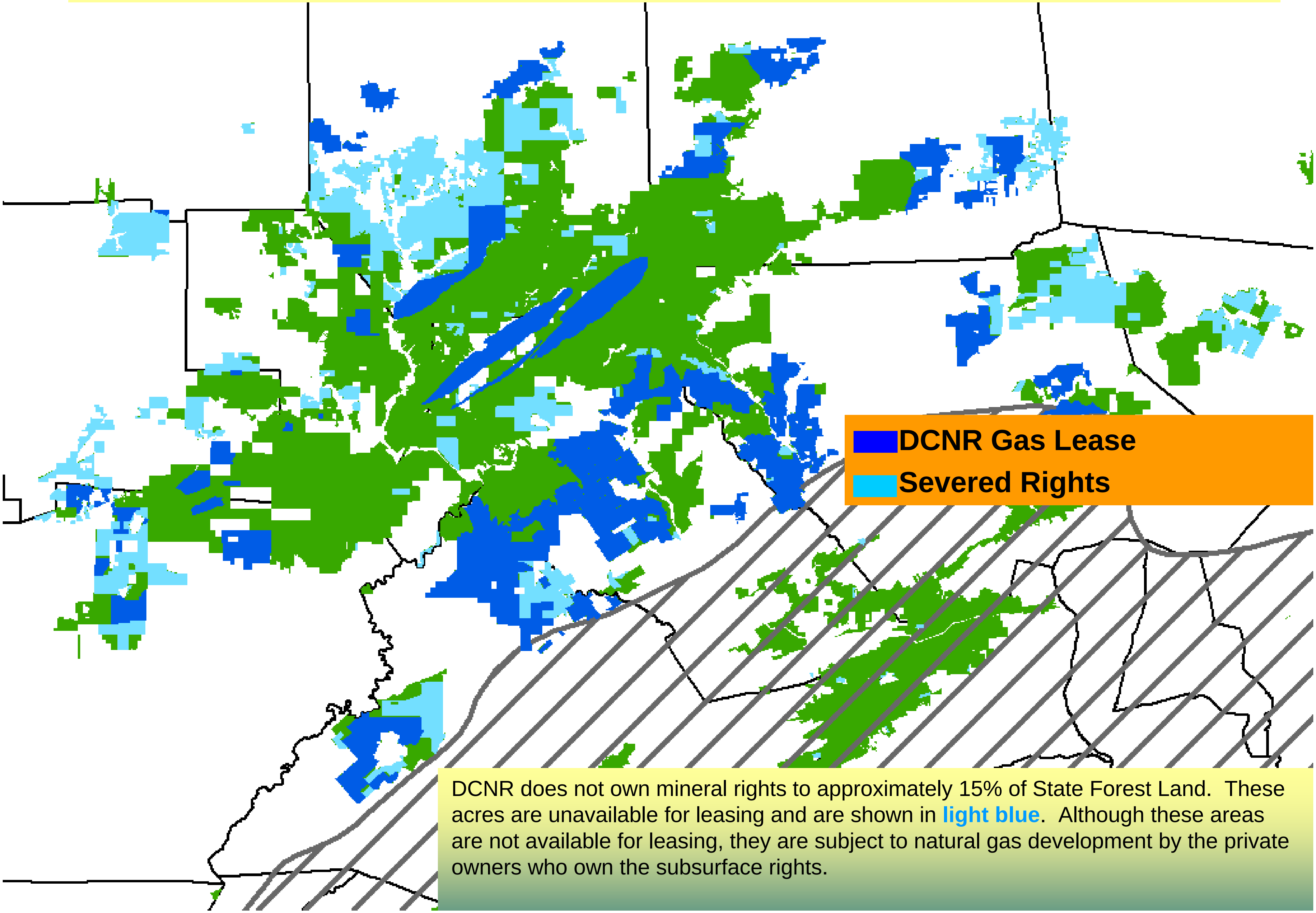
Let's now step back and take a bigger picture look among all the analyses shown – existing leases, severed rights, the forest's wild character, ecological considerations, and the conservancy's priority forest patches.

Cumulative Assessment & Impacts



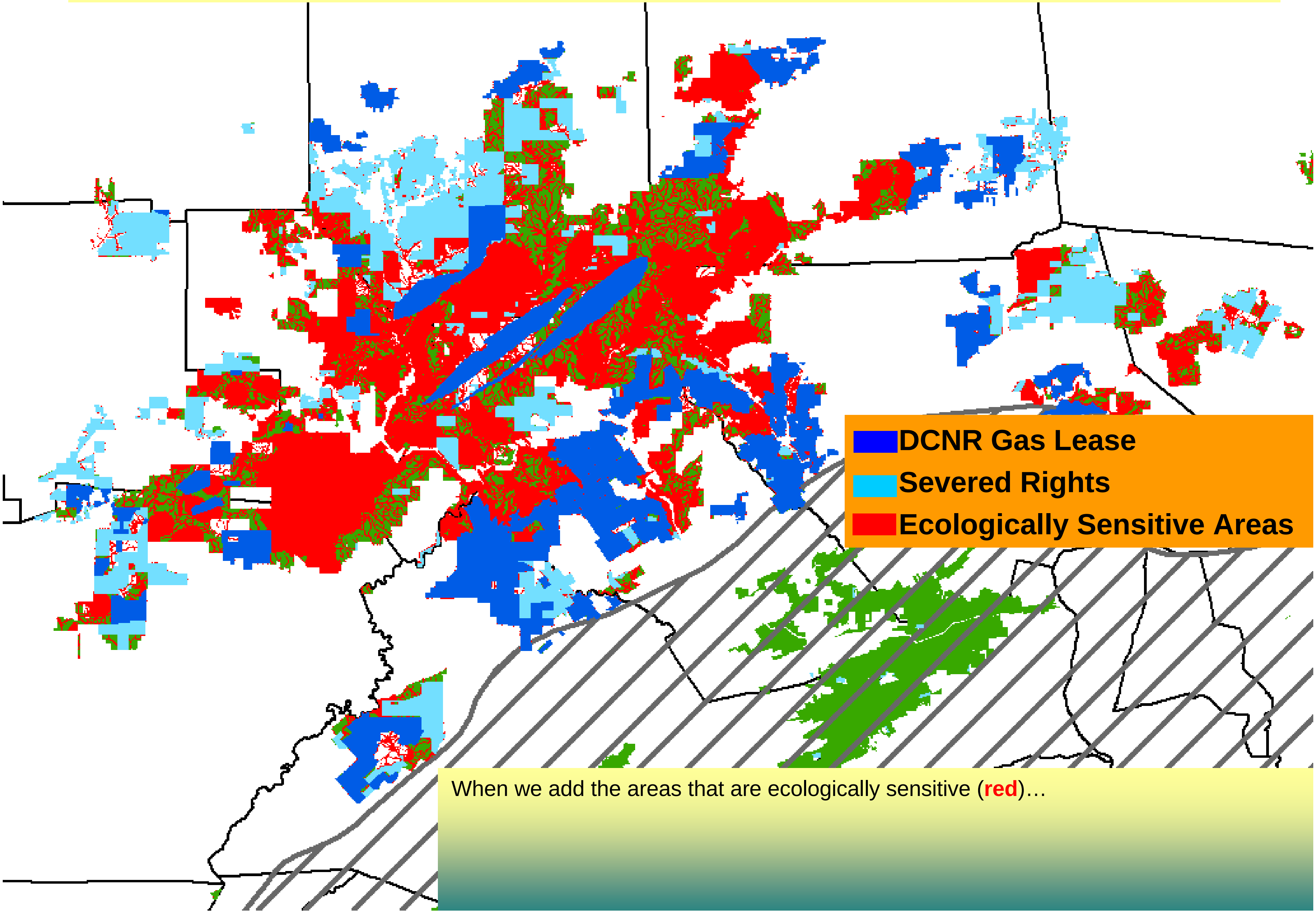
Much of the State Forest System has already been leased for Natural Gas. These areas are shown in **dark blue**.

Cumulative Assessment & Impacts



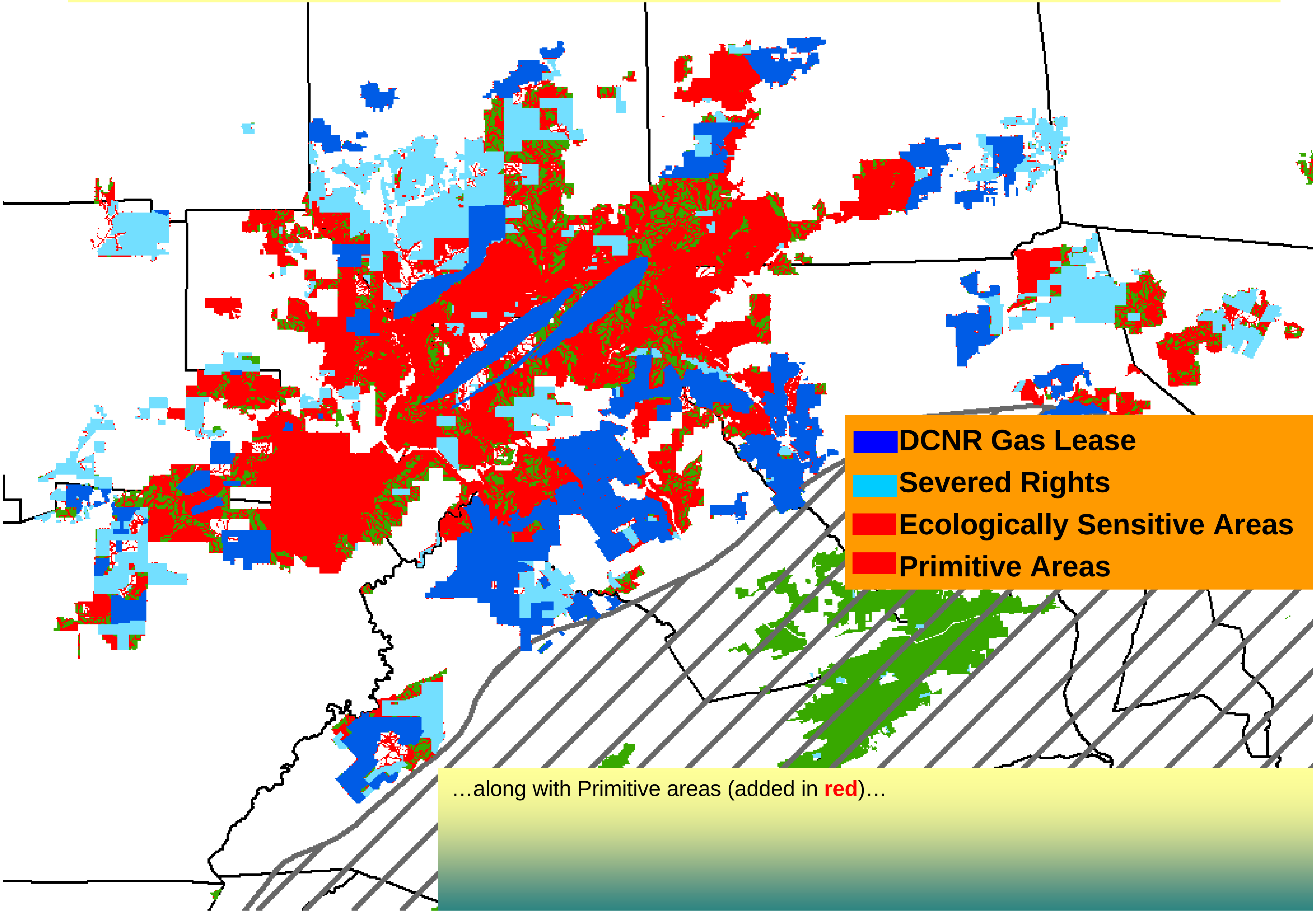
DCNR does not own mineral rights to approximately 15% of State Forest Land. These acres are unavailable for leasing and are shown in **light blue**. Although these areas are not available for leasing, they are subject to natural gas development by the private owners who own the subsurface rights.

Cumulative Assessment & Impacts



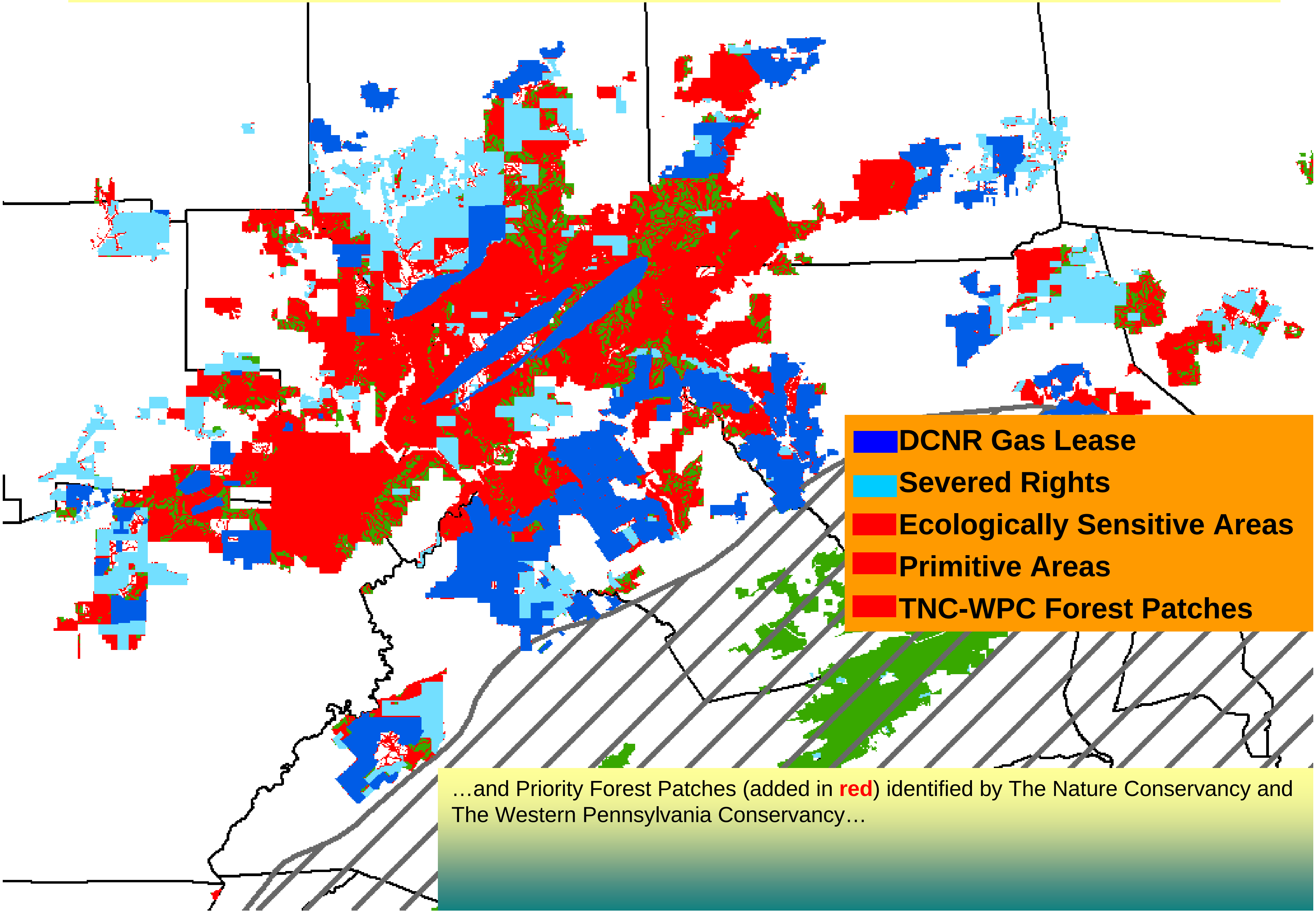
When we add the areas that are ecologically sensitive (**red**)…

Cumulative Assessment & Impacts



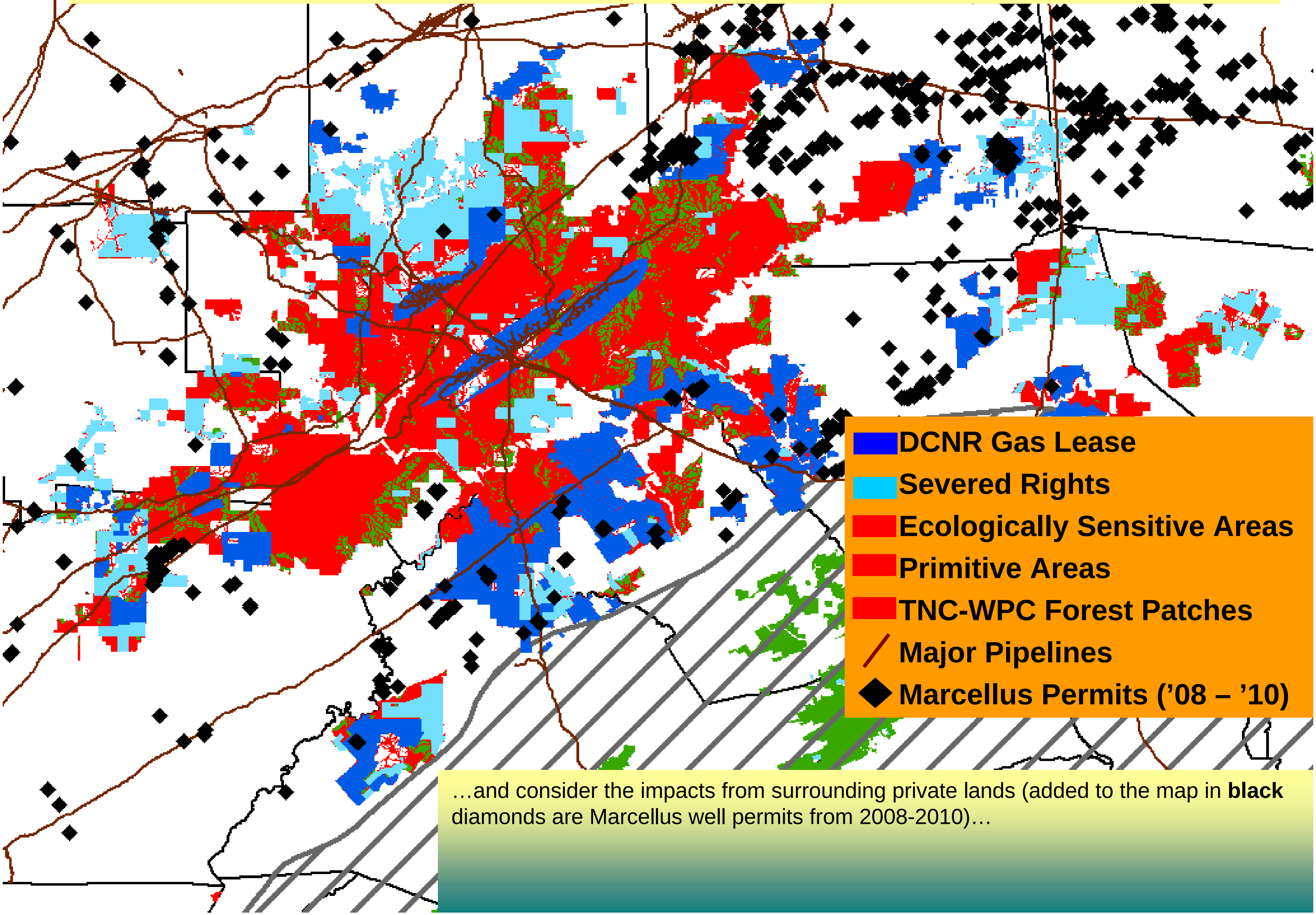
…along with Primitive areas (added in **red**)…

Cumulative Assessment & Impacts



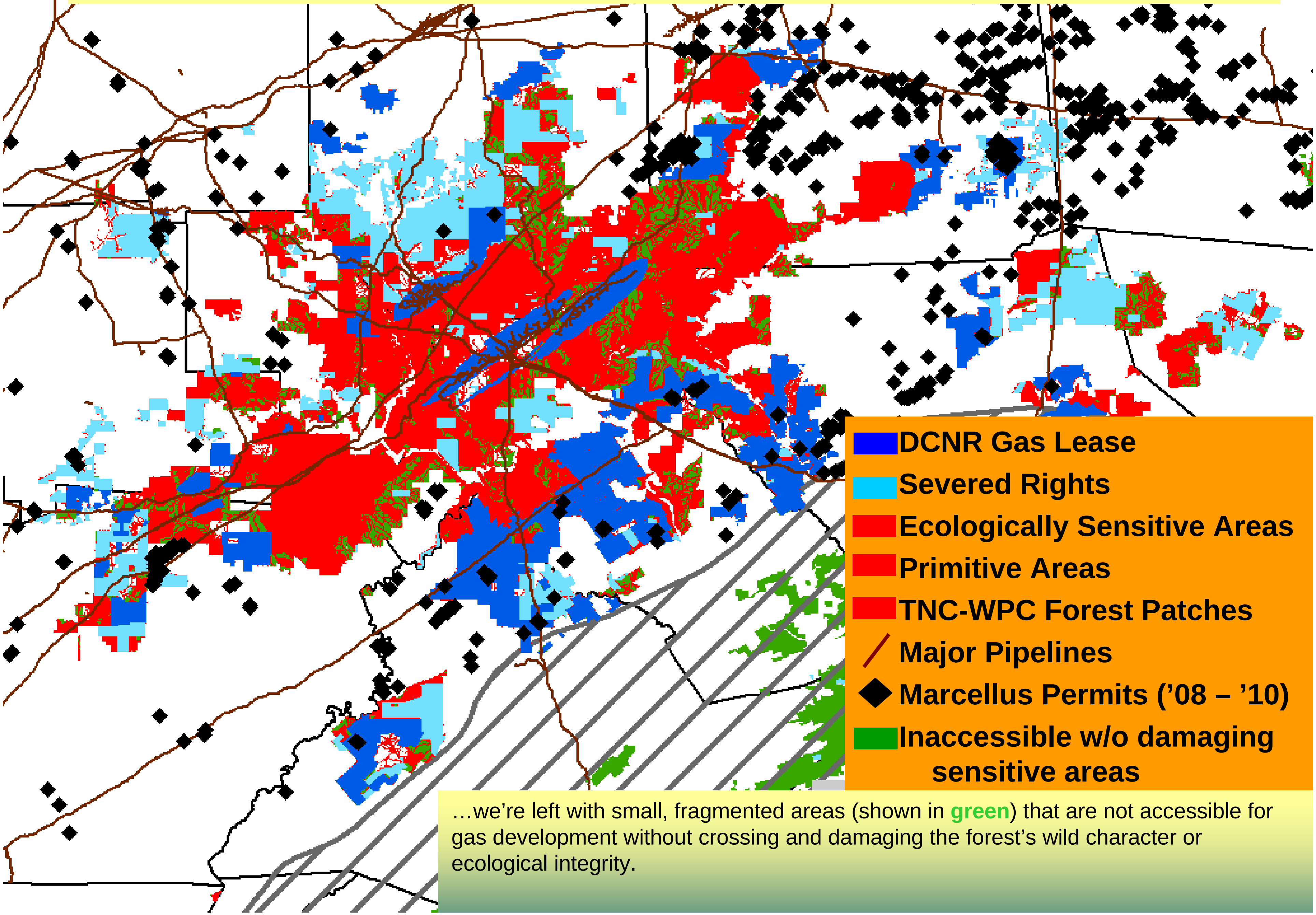
…and Priority Forest Patches (added in **red**) identified by The Nature Conservancy and The Western Pennsylvania Conservancy…

Cumulative Assessment & Impacts



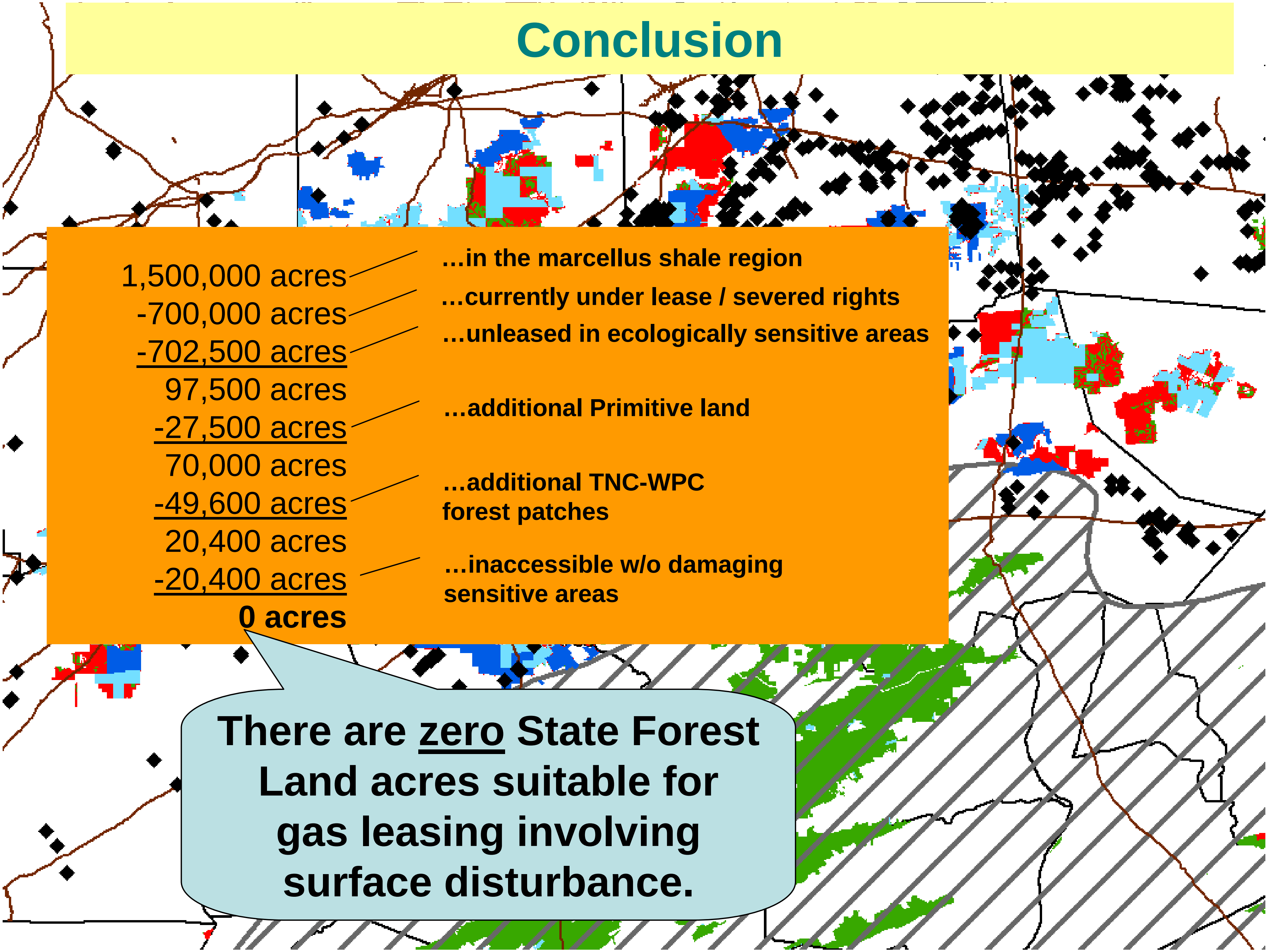
…and consider the impacts from surrounding private lands (added to the map in **black** diamonds are Marcellus well permits from 2008-2010)…

Cumulative Assessment & Impacts



…we're left with small, fragmented areas (shown in green) that are not accessible for gas development without crossing and damaging the forest's wild character or ecological integrity.

Conclusion



1,500,000 acres	…in the marcellus shale region
-700,000 acres	…currently under lease / severed rights
-702,500 acres	…unleased in ecologically sensitive areas
97,500 acres	
-27,500 acres	…additional Primitive land
70,000 acres	
-49,600 acres	…additional TNC-WPC forest patches
20,400 acres	
-20,400 acres	…inaccessible w/o damaging sensitive areas
0 acres	

There are zero State Forest Land acres suitable for gas leasing involving surface disturbance.

Clean Energy

Air Emissions

Various Energy Resources

- Air Emissions
- Water Resource Use
- Water Discharges
- Solid Waste Generation
- Land Resource Use

Electricity generation is the dominant industrial source of air emissions in the United States today. Fossil fuel-fired power plants are responsible for 67 percent of the nation's sulfur dioxide emissions, 23 percent of nitrogen oxide emissions, and 40 percent of man-made carbon dioxide emissions. These emissions can lead to smog, acid rain, and haze. In addition, these power plant emissions increase the risk of climate change. Congress is currently considering proposals to require further reductions of emissions from power plants, including the President's Clear Skies Initiative. However, renewable energy is receiving increased attention by environmental policymakers because renewable energy technologies have significantly lower emissions than traditional power generation technologies. To find out more about the air emissions generated by U.S. power plants, you can use EPA's Emissions and Generated Resource Integrated Database, or eGRID. eGRID provides emissions data on virtually every power plant and company that generates electricity in the United States.

The air emissions impacts of electricity generation vary from technology to technology, as described below.

Natural Gas

At the power plant, the burning of natural gas produces nitrogen oxides and carbon dioxide, but in lower quantities than burning coal or oil. Methane, a primary component of natural gas and a greenhouse gas, can also be emitted into the air when natural gas is not burned completely. Similarly, methane can be emitted as the result of leaks and losses during transportation. Emissions of sulfur dioxide and mercury compounds from burning natural gas are negligible.

The average emissions rates in the United States from natural gas-fired generation are: 1135 lbs/MWh of carbon dioxide, 0.1 lbs/MWh of sulfur dioxide, and 1.7 lbs/MWh of nitrogen oxides.[1] Compared to the average air emissions from coal-fired generation, natural gas produces half as much carbon dioxide, less than a third as much nitrogen oxides, and one percent as much sulfur oxides at the power plant. In addition, the process of extraction, treatment, and transport of the natural gas to the power plant generates additional emissions.[2]

Coal

When coal is burned, carbon dioxide, sulfur dioxide, nitrogen oxides, and mercury compounds are released. For that reason, coal-fired boilers are required to have control devices to reduce the amount of emissions that are released.

The average emission rates in the United States from coal-fired generation are: 2,249 lbs/MWh of carbon dioxide, 13 lbs/MWh of sulfur dioxide, and 6 lbs/MWh of nitrogen oxides.[3]

Mining, cleaning, and transporting coal to the power plant generate additional emissions. For example, methane, a potent greenhouse gas that is trapped in the coal, is often vented during these processes to increase safety.

Oil

Burning oil at power plants produces nitrogen oxides, sulfur dioxide, carbon dioxide, methane, and mercury compounds. The amount of sulfur dioxide and mercury compounds can vary greatly depending on the sulfur and mercury content of the oil that is burned.

The average emissions rates in the United States from oil-fired generation are: 1672 lbs/MWh of carbon dioxide, 12 lbs/MWh of sulfur dioxide, and 4 lbs/MWh of nitrogen oxides.[4]

In addition, oil wells and oil collection equipment are a source of emissions of methane, a potent greenhouse gas. The large engines that are used in the oil drilling, production, and transportation processes burn natural gas or diesel that also produce emissions.

Nuclear Energy

Nuclear power plants do not emit carbon dioxide, sulfur dioxide, or nitrogen oxides. However, fossil fuel emissions are associated with the uranium mining and uranium enrichment process as well as the transport of the uranium fuel to the nuclear plant.

Municipal Solid Waste

Although municipal solid waste (MSW) includes renewable resources, its use as a source of energy has been met with controversy. Despite recent toughening of emission standards for MSW combustion, the process creates significant emissions, including trace amounts of hazardous air pollutants.

Burning MSW produces nitrogen oxides and sulfur dioxide as well as trace amounts of toxic pollutants, such as mercury compounds and dioxins. Although MSW power plants do emit carbon dioxide, the primary greenhouse gas, the biomass-derived portion is considered to be part of the Earth's natural carbon cycle. The plants and trees that make up the paper, food, and other biogenic waste remove carbon dioxide from the air while they are growing, which is returned to the air when this material is burned. In contrast, when fossil fuels are burned, they release carbon dioxide that has not been part of the Earth's atmosphere for a very long time (i.e., within a human time scale).

The average air emission rates in the United States from municipal solid waste-fired generation are: 2988 lbs/MWh of carbon dioxide, (it is estimated that the fossil fuel-derived portion of carbon dioxide emissions represent approximately one-third of the total carbon dioxide emissions) 0.8 lbs/MWh of sulfur dioxide, and 5.4 lbs/MWh of nitrogen oxides.[5]

The variation in the composition of MSW raises concerns. For example, if MSW containing batteries and tires are burned, toxic materials are released into the air. A variety of air pollution control technologies are used to reduce most toxic air pollutants from MSW power plants.

If MSW were to be incinerated anyway, little or no environmental impact would be attributable to using the resulting heat to generate electricity. However, there are alternatives to incineration, such as recycling waste, storing waste in landfills, and source reduction.

Hydroelectricity

Hydropower's air emissions are negligible because no fuels are burned. However, if a large amount of vegetation is growing along the riverbed when a dam is built, it can decay in the lake that is created, causing the buildup and release of methane, a potent greenhouse gas.

Non-Hydroelectric Renewable Energy

Solar

Emissions associated with generating electricity from solar technologies are negligible because no fuels are combusted.

Geothermal

Emissions associated with generating electricity from geothermal technologies are negligible because no fuels are combusted.

Biomass

Biomass power plants emit nitrogen oxides and a small amount of sulfur dioxide. The amounts emitted depend on the type of biomass that is burned and the type of generator used. Although the burning of biomass also produces carbon dioxide, the primary greenhouse gas, it is considered to be part of the natural carbon cycle of the earth. The plants take up carbon dioxide from the air while they are growing and then return it to the air when they are burned, thereby causing no net increase. Biomass contains much less sulfur and nitrogen than coal;[6] therefore, when biomass is co-fired with coal, sulfur dioxide and nitrogen oxides emissions are lower than when coal is burned alone.[7] When the role of renewable biomass in the carbon cycle is considered, the carbon dioxide emissions that result from co-firing biomass with coal are lower than those from burning coal alone.[8]

Landfill Gas

Burning landfill gas produces nitrogen oxides emissions as well as trace amounts of toxic materials. The amount of these emissions can vary widely, depending on the waste from which the landfill gas was created. The carbon dioxide released from burning landfill gas is considered to be a part of the natural carbon cycle of the earth. Producing electricity from landfill gas avoids the need to use non-renewable resources to produce the same amount of electricity. In addition, burning landfill gas prevents the release of methane, a potent greenhouse gas, into the atmosphere.

Wind

Emissions associated with generating electricity from wind technology are negligible because no fuels are combusted.

1. U.S. EPA, eGRID 2000.
2. Ibid.
3. Ibid.
4. Ibid.
5. U.S. EPA, Compilation of Air Pollutant Emission Factors (AP-42).
6. U.S. Department of Energy, Energy Efficiency and Renewable Energy Clearinghouse, Biomass Cofiring: A Renewable Alternative for Utilities. June 2000. DOE/GO-102000-1055.
7. Ibid.
8. Ibid.

International Energy Agency

Golden Rules for a Golden Age of Gas

World Energy Outlook Special Report on Unconventional Gas

Golden Rules *for a* Golden Age *of* Gas

World Energy Outlook
Special Report on Unconventional Gas

Natural gas is poised to enter a golden age, but this future hinges critically on the successful development of the world's vast unconventional gas resources. North American experience shows unconventional gas – notably shale gas – can be exploited economically. Many countries are lining up to emulate this success.

But some governments are hesitant, or even actively opposed. They are responding to public concerns that production might involve unacceptable environmental and social damage.

This report, in the *World Energy Outlook* series, treats these aspirations and anxieties with equal seriousness. It features two new cases: a Golden Rules Case, in which the highest practicable standards are adopted, gaining industry a "social licence to operate"; and its counterpart, in which the tide turns against unconventional gas as constraints prove too difficult to overcome.

The report:

- Describes the unconventional gas resource and what is involved in exploiting it.
- Identifies the key environmental and social risks and how they can be addressed.
- Suggests the Golden Rules necessary to realise the economic and energy security benefits while meeting public concerns.
- Spells out the implications of compliance with these rules for governments and industry, including on development costs.
- Assesses the impact of the two cases on global gas trade patterns and pricing, energy security and climate change.

For more information, and the free download of this report, please visit: ***www.worldenergyoutlook.org***

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International Energy Agency

Golden Rules *for a* Golden Age *of* Gas

World Energy Outlook
Special Report on Unconventional Gas

INTERNATIONAL ENERGY AGENCY

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 28 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
- Find solutions to global energy challenges through engagement and dialogue with non-member countries, industry, international organisations and other stakeholders.

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The European Commission also participates in the work of the IEA.

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Natural gas is poised to enter a golden age, but will do so only if a significant proportion of the world's vast resources of unconventional gas – shale gas, tight gas and coalbed methane – can be developed profitably and in an environmentally acceptable manner. Advances in upstream technology have led to a surge in the production of unconventional gas in North America in recent years, holding out the prospect of further increases in production there and the emergence of a large-scale unconventional gas industry in other parts of the world, where sizeable resources are known to exist. The boost that this would give to gas supply would bring a number of benefits in the form of greater energy diversity and more secure supply in those countries that rely on imports to meet their gas needs, as well as global benefits in the form of reduced energy costs.

Yet a bright future for unconventional gas is far from assured: numerous hurdles need to be overcome, not least the social and environmental concerns associated with its extraction. Producing unconventional gas is an intensive industrial process, generally imposing a larger environmental footprint than conventional gas development. More wells are often needed and techniques such as hydraulic fracturing are usually required to boost the flow of gas from the well. The scale of development can have major implications for local communities, land use and water resources. Serious hazards, including the potential for air pollution and for contamination of surface and groundwater, must be successfully addressed. Greenhouse-gas emissions must be minimised both at the point of production and throughout the entire natural gas supply chain. Improperly addressed, these concerns threaten to curb, if not halt, the development of unconventional resources.

The technologies and know-how exist for unconventional gas to be produced in a way that satisfactorily meets these challenges, but a continuous drive from governments and industry to improve performance is required if public confidence is to be maintained or earned. The industry needs to commit to apply the highest practicable environmental and social standards at all stages of the development process. Governments need to devise appropriate regulatory regimes, based on sound science and high-quality data, with sufficient compliance staff and guaranteed public access to information. Although there is a range of other factors that will affect the development of unconventional gas resources, varying between different countries, our judgement is that there is a critical link between the way that governments and industry respond to these social and environmental challenges and the prospects for unconventional gas production.

We have developed a set of "Golden Rules", suggesting principles that can allow policy-makers, regulators, operators and others to address these environmental and social impacts.[1] We have called them Golden Rules because their application can bring a level of environmental performance and public acceptance that can maintain or earn the industry a "social licence to operate" within a given jurisdiction, paving the way for the widespread development of unconventional gas resources on a large scale, boosting overall gas supply and making the golden age of gas a reality.

The Golden Rules underline that full transparency, measuring and monitoring of environmental impacts and engagement with local communities are critical to addressing public concerns. Careful choice of drilling sites can reduce the above-ground impacts and most effectively target the productive areas, while minimising any risk of earthquakes or of fluids passing between geological strata. Leaks from wells into aquifers can be prevented by high standards of well design, construction and integrity testing. Rigorous assessment and monitoring of water requirements (for shale and tight gas), of the quality of produced water (for coalbed methane) and of waste water for all types of unconventional gas can ensure informed and stringent decisions about water handling and disposal. Production-related emissions of local pollutants and greenhouse-gas emissions can be reduced by investments to eliminate venting and flaring during the well-completion phase.

We estimate that applying the Golden Rules could increase the overall financial cost of development a typical shale-gas well by an estimated 7%. However, for a larger development project with multiple wells, additional investment in measures to mitigate environmental impacts may be offset by lower operating costs.

In our Golden Rules Case, we assume that the conditions are in place, including approaches to unconventional gas development consistent with the Golden Rules, to allow for a continued global expansion of gas supply from unconventional resources, with far-reaching consequences for global energy markets. Greater availability of gas has a strong moderating impact on gas prices and, as a result, global gas demand rises by more than 50% between 2010 and 2035. The increase in demand for gas is equal to the growth coming from coal, oil and nuclear combined, and ahead of the growth in renewables. The share of gas in the global energy mix reaches 25% in 2035, overtaking coal to become the second-largest primary energy source after oil.

1. Consultations with a range of stakeholders when developing these Golden Rules included a high-level workshop held in Warsaw on 7 March 2012, which was organised by the IEA, hosted by the Polish Ministry of Economy and co-hosted by the Mexican Ministry of Energy. In addition to the input received during this workshop, we have drawn upon the extensive work in this area undertaken by many governments, non-governmental and academic organisations, and industry associations.

Production of unconventional gas, primarily shale gas, more than triples in the Golden Rules Case to 1.6 trillion cubic metres in 2035. This accounts for nearly two-thirds of incremental gas supply over the period to 2035, and the share of unconventional gas in total gas output rises from 14% today to 32% in 2035. Most of the increase comes after 2020, reflecting the time needed for new producing countries to establish a commercial industry. The largest producers of unconventional gas over the projection period are the United States, which moves ahead of Russia as the largest global natural gas producer, and China, whose large unconventional resource base allows for very rapid growth in unconventional production starting towards 2020. There are also large increases in Australia, India, Canada and Indonesia. Unconventional gas production in the European Union, led by Poland, is sufficient after 2020 to offset continued decline in conventional output.

Global investment in unconventional production constitutes 40% of the $6.9 trillion (in year-2010 dollars) required for cumulative upstream gas investment in the Golden Rules Case. Countries that were net importers of gas in 2010 (including the United States) account for more than three-quarters of total unconventional upstream investment, gaining the wider economic benefits associated with improved energy trade balances and lower energy prices. The investment reflects the high number of wells required: output at the levels anticipated in the Golden Rules Case would require more than one million new unconventional gas wells worldwide between now and 2035, twice the total number of gas wells currently producing in the United States.

The Golden Rules Case sees gas supply from a more diverse mix of sources of gas in most markets, suggesting growing confidence in the adequacy, reliability and affordability of natural gas. The developments having most impact on global gas markets and security are the increasing levels of unconventional gas production in China and the United States, the former because of the way that it slows the growth in Chinese import needs and the latter because it allows for gas exports from North America. These developments in tandem increase the volume of gas, particularly liquefied natural gas (LNG), looking for markets in the period after 2020, which stimulates the development of more liquid and competitive international markets. The share of Russia and countries in the Middle East in international gas trade declines in the Golden Rules Case from around 45% in 2010 to 35% in 2035, although their gas exports increase by 20% over the same period.

In a Low Unconventional Case, we assume that – primarily because of a lack of public acceptance – only a small share of the unconventional gas resource base is accessible for development. As a result, unconventional gas production in aggregate rises only slightly above current levels by 2035. The competitive position of gas in the global fuel mix deteriorates as a result of lower availability and higher prices, and the share of gas in global energy use increases only slightly, from 21% in 2010 to 22% in 2035, remaining well behind that of coal. The volume of inter-regional trade is higher than in the Golden Rules Case and some patterns of trade are reversed, with North America requiring significant quantities of imported LNG. The Low Unconventional Case reinforces the preeminent position in global supply of the main conventional gas resource-holders.

Energy-related CO_2 emissions are 1.3% higher in the Low Unconventional Case than in the Golden Rules Case. Although the forces driving the Low Unconventional Case are led by environmental concerns, this offsets any claim that a reduction in unconventional gas output brings net environmental gains. Nonetheless, greater reliance on natural gas alone cannot realise the international goal of limiting the long-term increase in the global mean temperature to two degrees Celsius above pre-industrial levels. Achieving this climate target will require a much more substantial shift in global energy use. Anchoring unconventional gas development in a broader energy policy framework that embraces greater improvements in energy efficiency, more concerted efforts to deploy low-carbon energy sources and broad application of new low-carbon technologies, including carbon capture and storage, would help to allay the fear that investment in unconventional gas comes at their expense.

Measure, disclose and engage

- Integrate engagement with local communities, residents and other stakeholders into each phase of a development starting prior to exploration; provide sufficient opportunity for comment on plans, operations and performance; listen to concerns and respond appropriately and promptly.
- Establish baselines for key environmental indicators, such as groundwater quality, prior to commencing activity, with continued monitoring during operations.
- Measure and disclose operational data on water use, on the volumes and characteristics of waste water and on methane and other air emissions, alongside full, mandatory disclosure of fracturing fluid additives and volumes.
- Minimise disruption during operations, taking a broad view of social and environmental responsibilities, and ensure that economic benefits are also felt by local communities.

Watch where you drill

- Choose well sites so as to minimise impacts on the local community, heritage, existing land use, individual livelihoods and ecology.
- Properly survey the geology of the area to make smart decisions about where to drill and where to hydraulically fracture: assess the risk that deep faults or other geological features could generate earthquakes or permit fluids to pass between geological strata.
- Monitor to ensure that hydraulic fractures do not extend beyond the gas-producing formations.

Isolate wells and prevent leaks

- Put in place robust rules on well design, construction, cementing and integrity testing as part of a general performance standard that gas bearing formations must be completely isolated from other strata penetrated by the well, in particular freshwater aquifers.
- Consider appropriate minimum-depth limitations on hydraulic fracturing to underpin public confidence that this operation takes place only well away from the water table.
- Take action to prevent and contain surface spills and leaks from wells, and to ensure that any waste fluids and solids are disposed of properly.

Treat water responsibly

- Reduce freshwater use by improving operational efficiency; reuse or recycle, wherever practicable, to reduce the burden on local water resources.
- Store and dispose of produced and waste water safely.
- Minimise use of chemical additives and promote the development and use of more environmentally benign alternatives.

Eliminate venting, minimise flaring and other emissions

- Target zero venting and minimal flaring of natural gas during well completion and seek to reduce fugitive and vented greenhouse-gas emissions during the entire productive life of a well.
- Minimise air pollution from vehicles, drilling rig engines, pump engines and compressors.

Be ready to think big

- Seek opportunities for realising the economies of scale and co-ordinated development of local infrastructure that can reduce environmental impacts.
- Take into account the cumulative and regional effects of multiple drilling, production and delivery activities on the environment, notably on water use and disposal, land use, air quality, traffic and noise.

Ensure a consistently high level of environmental performance

- Ensure that anticipated levels of unconventional gas output are matched by commensurate resources and political backing for robust regulatory regimes at the appropriate levels, sufficient permitting and compliance staff, and reliable public information.
- Find an appropriate balance in policy-making between prescriptive regulation and performance-based regulation in order to guarantee high operational standards while also promoting innovation and technological improvement.
- Ensure that emergency response plans are robust and match the scale of risk.
- Pursue continuous improvement of regulations and operating practices.
- Recognise the case for independent evaluation and verification of environmental performance.

Technology is opening up possibilities for unconventional gas to play a major role in the future global energy mix, a development that would ease concerns about the reliability, affordability and security of energy supply. In North America, production of unconventional gas – notably shale gas – has risen rapidly in recent years and is expected to dominate growth in overall US natural gas production in the coming years and decades. Naturally, there is keen interest in replicating this success in other parts of the world, where sizeable resources of unconventional gas are known to exist. This could give a major boost to gas supply worldwide and help take us into a "Golden Age of Gas" – the subject of a special *WEO* report released last year (IEA, 2011) (Box).

Box ▻ Linking the Golden Rules to a "Golden Age of Gas"

The IEA released an analysis in June 2011 whose title asked the question "Are We Entering a Golden Age of Gas?" (IEA, 2011). How does this report link back to that analysis?

The Golden Age of Gas Scenario (GAS Scenario) in 2011 built a positive outlook for the future role of natural gas on four main pillars: more ambitious assumptions about gas use in China; greater use of natural gas in transportation; an assumption of slower growth in global nuclear power capacity; and a more optimistic outlook for gas supply – primarily though the availability of additional unconventional gas supplies at relatively low cost. In the GAS Scenario, as a result, natural gas increased its role in the future global energy mix from 21% to 25% over the period to 2035.

However, the question mark in the title of this publication was not accidental. It reflected continued uncertainties over the future of natural gas, in particular those connected with the potential for growth in unconventional gas supply. The present analysis zooms in on the environmental impacts of unconventional gas supply, how they are being, and might be, addressed and what the consequences might be. It should therefore be understood as a more detailed examination of a key pre-condition for a golden age of gas.

A range of factors will affect the pace of development of this relatively new industry over the coming decades. In our judgement, a key constraint is that unconventional gas does not yet enjoy, in most places, the degree of societal acceptance that it will require in order to flourish. Without a general, sustained and successful effort from both governments and operators to address the environmental and social concerns that have arisen, it may be impossible to convince the public that, despite the undoubted potential benefits, the impact and risks of unconventional gas development are acceptably small. The IEA offers this special report as a contribution to the solution of this dilemma. The objective is to suggest what might be required to enable the industry to maintain or earn a "social licence to operate".

In Chapter 1 of this special report, we analyse the specific characteristics of each type of unconventional gas development and their environmental and social impacts, examining the technologies and their associated risks, why they have raised public anxiety and why and how they require special attention from policy-makers, regulators and industry. This chapter develops a set of "Golden Rules", the application of which would reduce the impact of unconventional gas developments on land and water use, on the risk of water contamination, and on methane and other air emissions. It also analyses the implications of compliance with the Golden Rules for governments and for industry.

In Chapter 2, we set out the results of two sets of projections of future energy demand, supply and energy-related CO_2 emissions, which explore the potential impact of unconventional gas resources on energy markets. The first of these, to which the main part of this chapter is devoted, is a *Golden Rules Case*, which assumes that the conditions are put in place to allow for a continued expansion of gas supply from unconventional gas resources, including the effective application of the Golden Rules. This situation allows unconventional output to expand not only in North America but also in other countries around the world with major resources. A *Low Unconventional Case*, examined at the end of this chapter, considers the opposite turn of events, in which Golden Rules are not observed, opposition to unconventional gas hardens and the constraints prove too difficult to overcome.

Chapter 3 takes a closer look at unconventional gas in four key regions and countries: North America (United States, Canada and Mexico), China, Europe and Australia. The prospect of increased unconventional gas production is prompting many countries to review their regulatory frameworks to accommodate (or, in some cases, to restrict) the development of these resources. This chapter provides an overview of the main debates and challenges around unconventional production in the selected countries and regions, presented together with our projections for future output.

Addressing environmental risks

Why do we need "Golden Rules"?

Highlights

- Unconventional gas resources are trapped in very tight or low permeability rock and the effort required to extract them is greater than for conventional resources. This means higher intensity of drilling, entailing more industrial activity and disruption above ground. Producing gas from unconventional formations in many cases involves the use of hydraulic fracturing to boost the flow of gas from the well.
- The environmental and social hazards related to these and other features of unconventional gas development have generated keen public anxiety in many places. Means are available to address these concerns. "Golden Rules", as developed here, provide principles that can guide policy-makers, regulators, operators and other stakeholders on how best to reconcile their interests.
- Critical elements are: full transparency, measuring, monitoring and controlling environmental impacts; and early and sustained engagement. Careful choice of drilling sites can reduce the above-ground impacts and most effectively target the productive areas, while minimising any risk of earthquakes or of fluids passing between geological strata.
- Sound management of water resources is at the heart of the Golden Rules. Alongside robust rules on well design, construction, cementing and integrity testing to prevent leaks from the well into aquifers, this requires rigorous assessment, monitoring and handling of water requirements (for shale and tight gas), of the quality of produced water (for coalbed methane) and of waste water (in all cases).
- Unconventional gas has higher production-related greenhouse-gas emissions than conventional gas, but the difference can be reduced and emissions of other pollutants lowered by eliminating venting and minimising flaring during the well completion phase. Releases of methane, wherever they occur in the gas supply chain, are particularly damaging, given its potency as a greenhouse gas.
- The potential environmental impacts and the scale of unconventional gas development make it essential for policy-makers to ensure that effective and balanced regulation is in place, based on sound science and high-quality data, and that adequate resources are available for enforcement.
- Operators have to perform to the highest standards in order to win and retain the "social licence to operate". Application of the Golden Rules does affect costs, with an estimated 7% increase for a typical individual shale gas well. However, when considered across a complete licensing area, additional investment in measures to mitigate environmental impact can be offset in many cases by lower operating costs.

The environmental impact of unconventional gas production

Although known about for decades, the importance of global unconventional gas resources and their full extent has only recently been appreciated. Allowing for the uncertainties in the data, stemming, in part, from difficulties in distinguishing and categorising different types of gas (Box 1.1), we estimate that the remaining technically recoverable resources of unconventional gas worldwide approach the size of remaining conventional resources (which are 420 trillion cubic metres [tcm]). Remaining technically recoverable resources of shale gas are estimated to amount to 208 tcm, tight gas to 76 tcm and coalbed methane to 47 tcm. The economic and political significance of these unconventional resources lies not just in their size but also in their wide geographical distribution, which is in marked contrast to the concentration of conventional resources.[1] Availability of gas from a diverse range of sources would underpin confidence in gas as a secure and reliable source of energy.

Box 1.1 ▷ Unconventional gas resources

Unconventional gas refers to a part of the gas resource base that has traditionally been considered difficult or costly to produce. In this report, we focus on the three main categories of unconventional gas:

- **Shale gas** is natural gas contained within a commonly occurring rock classified as shale. Shale formations are characterised by low permeability, with more limited ability of gas to flow through the rock than is the case with a conventional reservoir. These formations are often rich in organic matter and, unlike most hydrocarbon reservoirs, are typically the original source of the gas, *i.e.* shale gas is gas that has remained trapped in, or close to, its source rock.
- **Coalbed methane**, also known as coal seam gas in Australia, is natural gas contained in coalbeds. Although extraction of coalbed methane was initially undertaken to make mines safer, it is now typically produced from non-mineable coal seams.
- **Tight gas**[2] is a general term for natural gas found in low permeability formations. Generally, we classify as tight gas those low permeability gas reservoirs that cannot produce economically without the use of technologies to stimulate flow of the gas towards the well, such as hydraulic fracturing.

Although the development cycle for unconventional gas and the technologies used in its production have much in common with those used in other parts of the upstream industry, unconventional gas developments do have some distinctive features and requirements, particularly in relation to the perceived higher risk of environmental damage and adverse

1. The extent and distribution of recoverable resources of unconventional gas is discussed in more detail in Chapter 2.

2. Tight gas is often a poorly defined category with no clear boundary between tight and conventional, nor between tight gas and shale gas.

social impacts. This helps to explain why the issue of unconventional gas exploitation has generated so much controversy.

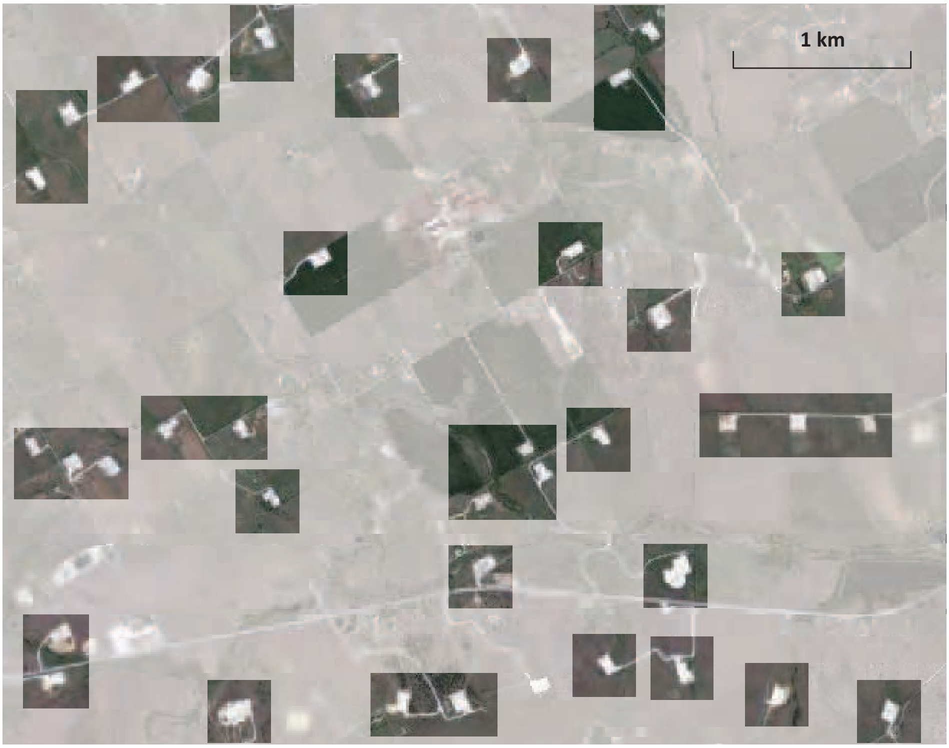
This chapter addresses these issues by examining in some depth what is involved in exploiting each category of unconventional gas and the associated hazards. It then proposes a set of principles, the "Golden Rules", applicable to future operations in this sector. The objective is to define the conditions which might enable the industry to gain or retain a "social licence to operate". The consequences for the energy sector of securing such an outcome are discussed in Chapters 2 and 3, together with the possible consequences of failing to do so.

The main reason for the potentially larger environmental impact of unconventional gas operations is the nature of the resources themselves: unconventional resources are less concentrated than conventional deposits and do not give themselves up easily. They are difficult to extract because they are trapped in very tight or low permeability rock that impedes their flow. Since the resources are more diffuse and difficult to produce, the scale of the industrial operation required for a given volume of unconventional output is much larger than for conventional production. This means that drilling and production activities can be considerably more invasive, involving a generally larger environmental footprint.

One feature of the greater scale of operations required to extract unconventional gas is the need for more wells. Whereas onshore conventional fields might require less than one well per ten square kilometres, unconventional fields might need more than one well per square kilometre (km^2), significantly intensifying the impact of drilling and completion activities on the environment and local residents.[3] A satellite image from Johnson County in Texas, United States illustrates this point, showing the density of well sites producing from the Barnett shale (Figure 1.1). This image highlights 37 well sites in an area of around 20 km^2, with each well site potentially having more than one well. Another important factor is the need for more complex and intensive preparation for production. While hydraulic fracturing is already used on occasions to stimulate conventional reservoirs, tight gas and shale gas developments almost always require the use of this technique in order to generate adequate flow rates into the well. The same technique is also often used, albeit less frequently, to produce coalbed methane. The associated use and release of water gives rise to a number of environmental concerns, including depletion of freshwater resources and possible contamination of surface water and aquifers.

3. It should be noted that conventional gas fields in mature areas, such as onshore United States or Canada, often have well densities (number of wells per unit area) comparable to those of unconventional gas. However, burgeoning unconventional gas production today tends to replace production that would have come from offshore locations or countries rich in conventional gas, such as Russia or Qatar, in which the well densities are much smaller.

Figure 1.1 ▷ **Drilling intensity in Johnson County, Texas**



Source: © 2012 Google, DigitalGlobe, GeoEye, Texas Orthoimagery Program, USDA Farm, Farm Service Agency source. Google Maps, http://g.co/maps/j9xws, with well sites highlighted.

The production of unconventional gas also contributes to the atmospheric concentration of greenhouse gases and affects local air quality. In some circumstances, unconventional gas production can result in higher airborne emissions of methane, a potent greenhouse gas, of volatile organic compounds (VOCs) that contribute to smog formation, and of carbon dioxide (CO_2) (from greater use of energy in the production process, compared with conventional production). Just how much greater these risks may be is uncertain: it depends critically on the way operations are carried out. On the other hand, there are potential net benefits from unconventional gas production, to the extent that, having been produced and transported to exacting environmental standards, it leads to greater use of gas instead of more carbon-intensive coal and oil.

In addition to the smaller recoverable hydrocarbon content per unit of land, unconventional developments tend to extend across much larger geographic areas. The Marcellus Shale in the United States covers more than 250 000 km^2, which is about ten times larger than the Hugoton Natural Gas Area in Kansas – the country's largest conventional gas producing zone. Moreover, areas with high unconventional potential are not always those with a strong or recent tradition of oil and gas industry activity; they are not necessarily rich in conventional hydrocarbons and in some cases there may have been little or no recent hydrocarbon production (and none expected). This tends to exacerbate the problem of public acceptance.

Shale and tight gas developments

Characteristics of the resource

By contrast to conventional gas reservoirs, shale gas reservoirs (Box 1.2) have very low permeability due to the fine-grained nature of the original sediments (gas does not flow easily out of the rock), fairly low porosities (relatively few spaces for the gas to be stored, generally less than 10% of the total volume), and low recovery rates (because the gas can be trapped in disconnected spaces within the rock or stuck to its surface). The last two factors (low porosity and low recovery) are responsible for the fact that the volume of recoverable hydrocarbons per square kilometre of area at the surface is usually an order of magnitude smaller than for conventional gas. Low permeability is responsible for shale gas requiring specific technologies, such as hydraulic fracturing, to achieve commercial flow rates.

Tight gas reservoirs originate in the same way as conventional gas reservoirs: the rock into which the gas migrates after being expelled from the source rock just happens to be of very low permeability. As a result, tight gas reservoirs also require special techniques to achieve commercial flow rates. On the other hand, they tend to have better recovery factors than shale gas deposits and, therefore, higher density of recoverable hydrocarbons per unit of surface area.

Box 1.2 ▷ What are shales and shale gas?

Shales are geological rock formations rich in clays, typically derived from fine sediments, deposited in fairly quiet environments at the bottom of seas or lakes, having then been buried over the course of millions of years. When a significant amount of organic matter has been deposited with the sediments, the shale rock can contain organic solid material called kerogen. If the rock has been heated up to sufficient temperatures during its burial history, part of the kerogen will have been transformed into oil or gas (or a mixture of both), depending on the temperature conditions in the rock. This transformation typically increases pressure within the rock, resulting in part of the oil and gas being expelled from the shale and migrating upwards into other rock formations, where it forms conventional oil and gas reservoirs. The shales are the source rock for the oil and gas found in such conventional reservoirs. Some, or occasionally all, of the oil and gas formed in the shale can remain trapped there, thus forming shale gas or light tight oil reservoirs.[4]

4. Terminology in this area remains to be standardised (see Box 1.1). Previous WEOs have classified light tight oil from shales as conventional oil. Note that the term light tight oil is preferred to that of shale oil, as the latter can bring confusion with oil shales, which are kerogen-rich shales that can be mined and heated to produce oil (IEA, 2010; IEA, 2011a).

Shales are ubiquitous in sedimentary basins: they typically form about 80% of what a well will drill through. As a result, the main organic-rich shales have already been identified in most regions of the world. Their depths vary from near surface to several thousand metres underground, while their thickness varies from just a few metres to several hundred.[5] Often, enough is known about the geological history to infer which shales are likely to contain gas (or oil, or a mixture of both). In that sense there is no real "exploration" required for shale gas. However, the amount of gas present and particularly the amount of gas that can be recovered technically and economically cannot be known until a number of wells have been drilled and tested. Each shale formation has different geological characteristics that affect the way gas can be produced, the technologies needed and the economics of production.[6] Different parts of the (generally large) shale deposits will also have different characteristics: small "sweet spots" or "core areas" may provide much better production than the rest of the play, often because of the presence of natural fractures that enhance permeability. The amount of natural gas liquids (NGLs) present in the gas can also vary considerably, with important implications for the economics of production. While most dry gas plays in the United States are probably uneconomic at the current low natural gas prices, plays with significant liquid content can be produced for the value of the liquids only (the market value of NGLs is correlated with oil prices, rather than gas prices), making gas an essentially free by-product.

Well construction[7]

The drilling phase is the most visible and disruptive in any oil and gas development – particularly so in the case of shale gas or tight gas because of the larger number of wells required. On land, a drilling rig, associated equipment and pits to store drilling fluids and waste typically occupy an area of 100 metres by 100 metres (the well site). Setting up drilling in a new location might involve between 100 and 200 truck movements to deliver all the equipment, while further truck movements will be required to deliver supplies during drilling and completion of the well.

Each well site needs to be chosen taking account not only of the subsurface geology, but also of a range of other concerns, including proximity to populated areas and existing infrastructure, the local ecology, water availability and disposal options, and seasonal restrictions related to climate or wildlife concerns. In North America, there has recently

5. Thin shales are generally considered as not exploitable. Depth can cut both ways: shallower shales require shallower, *i.e.* cheaper, wells, but deeper shales have higher pressures, which increases the areal density of recoverable gas (which is measured at surface conditions, while the gas in the shale is compressed by the formation pressure).

6. For example, horizontal wells with multi-stage hydraulic fracturing have been pivotal to the economic success of shale gas in the United States, while in Argentina, YPF has recently reported successful tests with vertical wells with only three or four hydraulic fractures (YPF, 2012).

7. The construction of a well to access unconventional gas deposits is divided into two phases: the drilling phase, where the hole is drilled to its target depth in sections that are secured with metal casing and cement; and the completion phase, where the cemented casing across the reservoir is perforated and the reservoir stimulated (generally by hydraulic fracturing) in order to start the production of hydrocarbons.

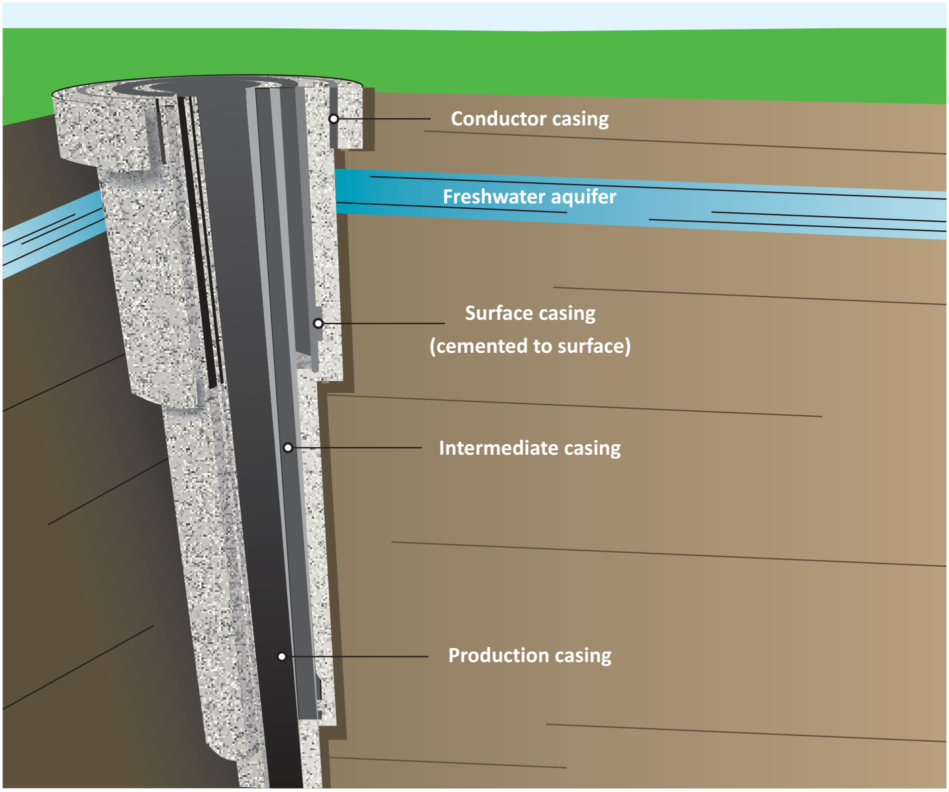
been a move towards drilling multiple wells from a single site, or pad, in order to limit the amount of disruption and thereby the overall environmental impact of well construction.[8] In 2011, according to industry sources, around 30% of all new shale and tight gas wells in the United States and Canada were multiple wells drilled from pads.

Once drilling starts, it is generally a 24-hour-per-day operation, creating noise and fumes from diesel generators, requiring lights at night and creating a regular stream of truck movements during mobilisation/demobilisation periods. Drilling operations can take anything from just a few days to several months, depending on the depth of the well and type of rock encountered. As the drill bit bores through the rock, drilling fluid known as "mud" is circulated through the wellbore in order, among other tasks, to control pressure in the well and remove cuttings created by the drill bit from the well. This lubricating "mud" consists of a base fluid, such as water or oil, mixed with salts and solid particles to increase its density and a variety of chemical additives. Mud is stored either in mobile containers or in open pits which are dug into the ground and lined with impermeable material. The volume of material in the pits needs to be monitored and contained to prevent leaks or spills. A drilling rig might have several hundred tonnes of mud in use at any one time, which creates a large demand for supplies. Once used, the mud must be either recycled or disposed of safely. Rock cuttings recovered from the mud during the drilling process amount to between 100 and 500 tonnes per well, depending on the depth. These, too, need to be disposed of in an environmentally acceptable fashion.

A combination of steel casing and cement in the well (Figure 1.2) provides an essential barrier to ensure that high-pressure gas or liquids from deeper down cannot escape into shallower rock formations or water aquifers. This barrier has to be designed to withstand the cycles of stress it will endure during the subsequent hydraulic fracturing, without suffering any cracks. The design aspects that are most important to ensure a leak-free well include the drilling of the well bore to specification (without additional twists, turns or cavities), the positioning of the casing in the centre of the well bore before it is cemented in place (this is done with centralisers placed at regular intervals along the casing as it is run in the hole, to keep it away from the rock face) and the correct choice of cement. The cement design needs to be studied both for its liquid properties during pumping (to ensure that it gets to the right place) and then for its mechanical strength and flexibility, so that it remains intact. The setting time of the cement is also a critical factor – cement that takes too long to set may have reduced strength; equally, cement that sets before it has been fully pumped into place requires difficult remedial action.

8. Pad drilling has long been used in northern areas, such as Alaska and in Russia, but the introduction of this practice to places such as Texas is relatively new.

Figure 1.2 ⊳ Typical well design and cementing



Source: Adapted from ConocoPhillips.

Well completion

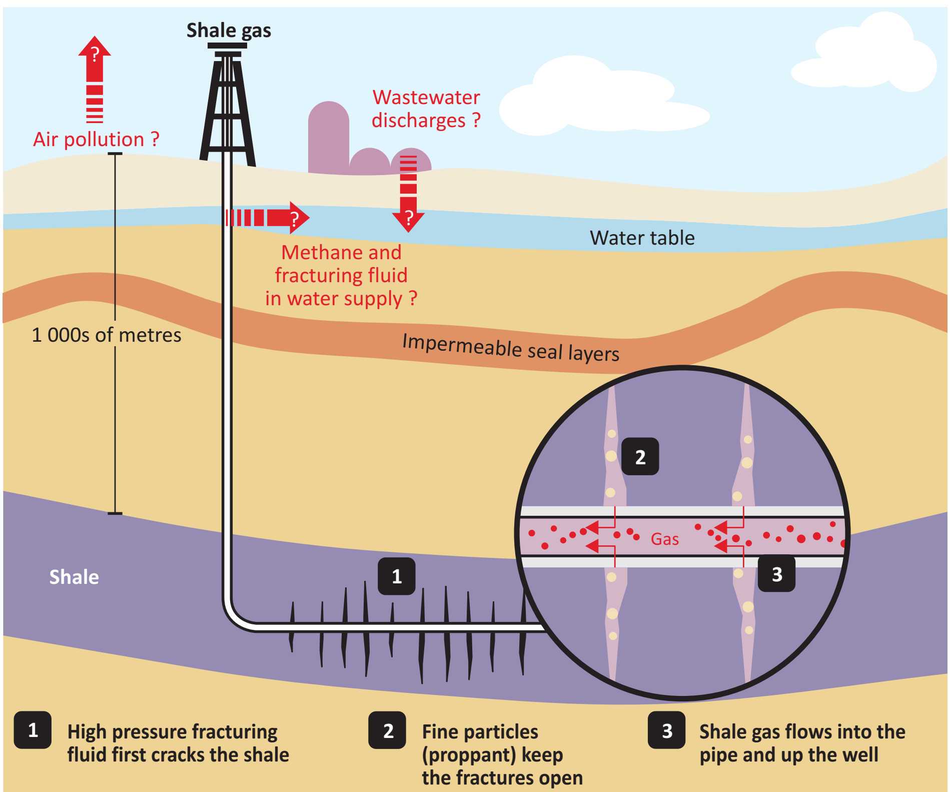
Once the well has been drilled, the final casing cemented in place across the gas-bearing rock has to be perforated in order to establish communication between the rock and the well.[9] The pressure in the well is then lowered so that hydrocarbons can flow from the rock to the well, driven by the pressure differential. With shale and tight gas, the flow will be very low, because of the low permeability of the rock. As the rate of hydrocarbon flow determines directly the cash flow from the well, low flow rates can mean there is insufficient revenue to pay for operating expenses and provide a return on the capital invested. Without additional measures to accelerate the flow of hydrocarbons to the well, the operation is then not economic.

Several technologies have been developed over the years to enhance the flow from low permeability reservoirs. Acid treatment, involving the injection of small amounts of strong acids into the reservoir to dissolve some of the rock minerals and enhance the permeability

9. Some wells are completed "open-hole", in which there is no casing in the final part of the well in the gas-bearing rock; this is not uncommon in horizontal wells.

of the rock near the wellbore, is probably the oldest and is still widely practised, particularly in carbonate reservoirs. Wells with long horizontal or lateral sections (known as horizontal wells) can increase dramatically the contact area between the reservoir rock and the wellbore, and are likewise effective in improving project economics. Hydraulic fracturing, developed initially in the late 1940s, is another effective and commonly-practised technology for low-permeability reservoirs. When rock permeability is extremely low, as in the case of shale gas or light tight oil, it often takes the combination of horizontal wells and hydraulic fracturing to achieve commercial rates of production (Figure 1.3). Advances in the application of these two techniques, in combination, largely explain the surge in shale gas production in the United States since 2005.

Figure 1.3 ▷ Shale gas production techniques and possible environmental hazards



Source: Adapted from Aldhous (2012).

Note: The possible environmental hazards discussed in the text are shown with red arrows. Although the figure illustrates a shale gas well with multi-stage hydraulic fracturing, some similar hazards are present with conventional gas wells, and with tight gas developments.

Hydraulic fracturing involves pumping a fluid – known as fracturing fluid – at high pressure into the well and then, far below the surface, into the surrounding target rock. This creates fractures or fissures a few millimetres wide in the rock. These fissures can extend tens or, in some cases, even hundreds of metres away from the well bore. Once the pressure is released, these fractures would tend to close again and not produce any lasting improvement in the flow of hydrocarbons. To keep the fractures open, small particles, such as sand or ceramic beads, are added to the pumped fluid to fill the fractures and to act as proppants, *i.e.* they prop open the fractures thus allowing the gas to escape into the well.

Box 1.3 ▷ Unconventional gas production and earthquake risks

There have been instances of earthquakes associated with unconventional gas production, for example the case of the Cuadrilla shale gas operations near Blackpool in the United Kingdom, or a case near Youngstown, Ohio, in the United States, which has been provisionally linked to injection of waste water, an operation that is similar in some respects to hydraulic fracturing. The registered earthquakes were small, of a magnitude of around two on the Richter scale, meaning they were discernible by humans but did not create any surface damage.

Because it creates cracks in rocks deep beneath the surface, hydraulic fracturing always generates small seismic events; these are actually used by petroleum engineers to monitor the process. In general, such events are several orders of magnitude too small to be detected at the surface: special observation wells and very sensitive instruments need to be used to monitor the process. Larger seismic events can be generated when the well or the fractures happen to intersect, and reactivate, an existing fault. This appears to be what happened in the Cuadrilla case.

Hydraulic fracturing is not the only anthropogenic process that can trigger small earthquakes. Any activity that creates underground stresses carries such a risk. Examples linked to construction of large buildings, or dams, have been reported. Geothermal wells in which cold water is circulated underground have been known to create enough thermally-induced stresses to generate earthquakes that can be sensed by humans (Cuenot, 2011). The same applies to deep mining (Redmayne, 1998). What is essential for unconventional gas development is to survey carefully the geology of the area to assess whether deep faults or other geological features present an enhanced risk and to avoid such areas for fracturing. In any case, monitoring is necessary so that operations can be suspended if there are signs of increased seismic activity.[10]

In many cases, a series of fractures is created at set intervals, one after the other, about every 100 metres along the horizontal well bore. This multi-stage fracturing technique has played a key role in unlocking production of shale gas and light tight oil in the United States and promises to do likewise elsewhere in the world. A standard single-stage hydraulic fracturing may pump down several hundred cubic metres of water together with proppant and a mixture of various chemical additives. In shale gas wells, a multi-stage fracturing

10. Detailed recommendations, following analysis of the Cuadrilla event, are under consideration by the United Kingdom Department of Energy and Climate Change (DECC, 2012).

would commonly involve between ten and twenty stages, multiplying the volumes of water and solids by 10 or 20, and hence the total values for water use might reach from a few thousand to up to twenty thousand cubic metres of water per well and volumes of proppant of the order of 1 000 to 4 000 tonnes per well. The repeated stresses on the well from multiple high-pressure procedures increase the premium on good well design and construction to ensure that gas bearing formations are completely isolated from other strata penetrated by the well.

Once the hydraulic fracturing has been completed, some of the fluid injected during the process flows back up the well as part of the produced stream, though typically not all of it – some remains trapped in the treated rock. During this flow-back period, typically over days (for a single-stage fracturing) to weeks (for a multi-stage fracturing), the amount of flow back of fracturing fluid decreases, while the hydrocarbon content of the produced stream increases, until the flow from the well is primarily hydrocarbons.

Best practice during this period is to use a so-called "green completion" or "reduced-emissions completion", whereby the hydrocarbons are separated from the fracturing fluid (and then sold) and the residual flow-back fluid is collected for processing and recycling or disposal. However, while collecting and processing the fluid is standard practice, capturing and selling the gas during this initial flow-back phase requires investment in gas separation and processing facilities, which does not always take place. In these cases, there can be venting of gas to the atmosphere (mostly methane, with a small fraction of VOCs) or flaring (burning) of hydrocarbon or hydrocarbon/water mixtures. Venting and/or flaring of the gas at this stage are the main reasons why shale and tight gas can give rise to higher greenhouse-gas emissions than conventional production (see the later section on methane and other airborne emissions).

Production

Once wells are connected to processing facilities, the main production phase can begin. During production, wells will produce hydrocarbons and waste streams, which have to be managed. But the well site itself is now less visible: a "Christmas tree" of valves, typically one metre high, is left on top of the well, with production being piped to processing facilities that usually serve several wells; the rest of the well site can be reclaimed. In some cases, the operator may decide to repeat the hydraulic fracturing procedure at later times in the life of the producing well, a procedure called re-fracturing. This was more frequent in vertical wells but is currently relatively rare in horizontal wells, occurring in less than 10% of the horizontal shale-gas wells drilled in the United States.

The production phase is the longest phase of the lifecycle. For a conventional well, production might last 30 years or more. For an unconventional development, the productive life of a well is expected to be similar, but shale gas wells typically exhibit a burst of initial production and then a steep decline, followed by a long period of relatively low production. Output typically declines by between 50% and 75% in the first year of production, and most recoverable gas is usually extracted after just a few years (IEA, 2009).

Well abandonment

At the end of their economic life, wells need to be safely abandoned, facilities dismantled and land returned to its natural state or put to new appropriate productive use. Long-term prevention of leaks to aquifers or to the surface is particularly important. Since much of the abandonment will not take place until production has ceased, the regulatory framework needs to ensure that the companies concerned make the necessary financial provisions and maintain technical capacity beyond the field's economic life to ensure that abandonment is completed satisfactorily, and well integrity maintained over the long term.

Coalbed methane developments

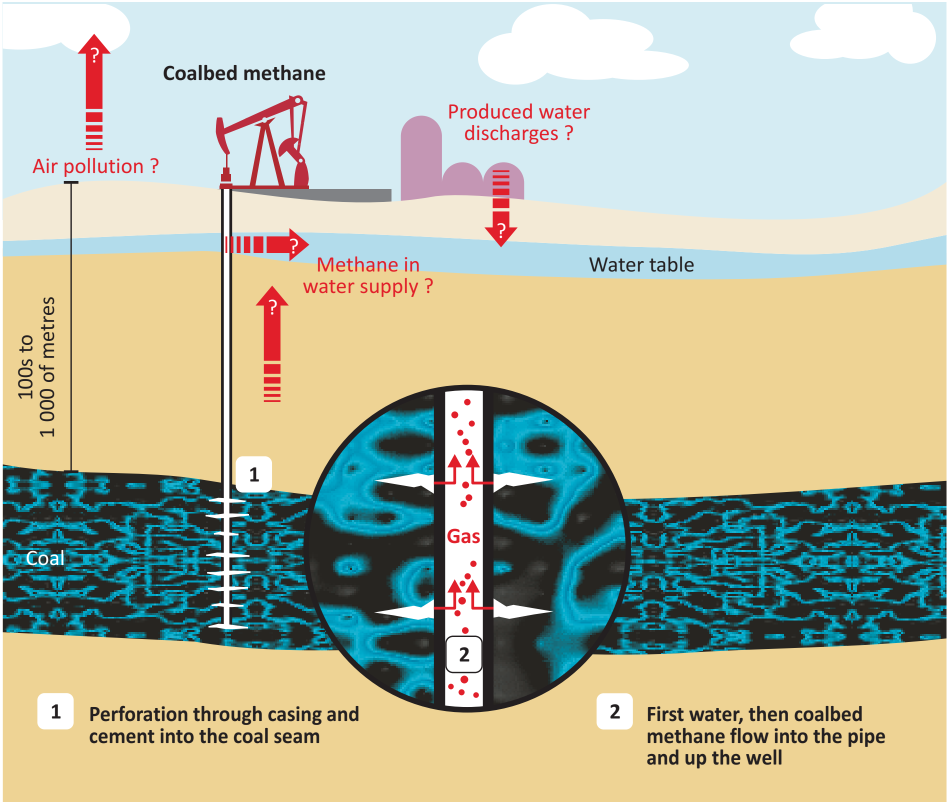
Coalbed methane refers to methane (natural gas) held within the solid matrix of coal seams. Some of the methane is stored within the coal as a result of a process called adsorption, whereby a film of methane is created on the surface of the pores inside the coal. Open fractures in the coal may also contain free gas or water. In some cases, methane is present in large volumes in coalbeds and can constitute a serious safety hazard for coal-mining operations. Significant volumes of CO_2 may also be present in the coal.

There are both similarities and differences between coalbed methane and the two other main types of unconventional gas discussed, which are linked to the way in which coalbed methane is extracted, the associated costs and the impact on the environment. The main similarity is the low permeability of the gas-bearing reservoir – a critical factor for the technical and economic viability of extraction. Virtually all the permeability of a coalbed is due to fractures, in the form of cleats and joints. These fractures tend to occur naturally so that, within a small part of the seam, methane is able to flow through the coalbed. As with shale and tight gas deposits, there are major variations in the concentration of gas from one area to another within the coal seams. This, together with variations in the thickness of the seam, has a significant impact on potential production rates.

Above ground, coalbed methane production involves disruption to the landscape and local environment through the construction of drilling pads and access roads, and the installation of on-site production equipment, gas processing and transportation facilities. As is often the case with shale gas and tight gas, coalbed methane developments require the drilling of more wells than conventional oil and gas production; as a result, traffic and vehicle noise levels, noise from compressors, air pollution and the potential damage to local ecological systems are generally more of an issue than for conventional gas output.

There are some important differences between coalbed methane and shale or tight gas resources. Coalbed methane deposits can be located at shallow depths (these are predominantly the deposits that have been exploited thus far), whereas shale and tight gas are usually found further below the surface. Water is often present in the coalbed, which needs to be removed to allow the gas to flow to the well. In addition, coalbed methane contains very few heavier liquid hydrocarbons (natural gas liquids or gas condensate), which means the commercial viability of production depends heavily on the price at which the gas itself can be sold; in the case of shale gas produced together with large volumes of associated natural gas liquids, the price of oil plays a very important role in determining the overall profitability of the development project.

Figure 1.4 ▷ Coalbed methane production techniques and possible environmental hazards



Source: Adapted from Aldhous (2012).

Note: The possible environmental hazards discussed in the text are shown with red arrows.

Considerable progress has been made over the last 25 years in honing techniques to extract coalbed methane on a commercial basis, paving the way to production on a significant scale, initially in North America and, since the mid-1990s, in Australia. Coalbed methane can be produced from vertical or horizontal wells. The latter are becoming increasingly common, though less so than for shale gas. Generally, the thinner the coal seam and the greater the depth of the deposit, the more likely it is that a horizontal well will be drilled. Although a depth of 800 to 1 200 metres is typical, in some cases coalbed methane is located in shallow formations as little as 100 metres below the surface, making it more economical to drill a series of vertical wells, rather than a horizontal well with extended reach along the coal seam. For shallow deposits, wells can often be drilled using water-well drilling equipment, rather than rigs designed for conventional hydrocarbon extraction, with commensurately cheaper costs (US EPA, 2010). For deeper formations (400 to 1 200 metres), both vertical and horizontal wells are used and custom-built small drilling rigs, capable of handling blow-out risks, have been developed.

Once a well is drilled, the water in the coalbed is extracted, either under natural pressure or by using mechanical pumping equipment – a process known as dewatering (water use and contamination risks are discussed in more detail in the next section). As subsurface pressure drops with dewatering, the flow of natural gas previously held in place by water pressure increases initially as it is released from the natural fractures or cleats within the coalbed. The gas is separated from the water at the surface and is then compressed and injected into a gas-gathering pipeline for onward transportation.

As in the case of shale gas, the rate of production of coalbed methane is often significantly lower than that achieved in conventional gas reservoirs; it also tends to reach a peak quickly as water is extracted, before entering a period of decline as the well pressure drops further. A well's typical lifespan is between five and fifteen years, with maximum gas production often achieved after one to six months of water removal (Horsley & Witten, 2001). In most cases, the low natural permeability of the coal seam means that gas can flow into the well from only a small segment of the coal seam – a characteristic shared with shale and tight gas. As a result, a relatively large number of wells is required over the area of the coalbed, especially if they are drilled vertically.

In some cases, it may also be necessary to use hydraulic fracturing to increase the permeability of the coal seam in order to stimulate the release of water and gas. This is normally practised only in deeper wells, typically at several hundred metres below the ground. The decision to proceed with hydraulic fracturing needs to be made before drilling begins, as the well and surface facilities need to be designed accordingly. The approach is similar to that described above, but in contrast to current practice with shale gas and tight gas wells, fracturing for coalbed methane production is frequently a single-stage process, *i.e.* one fracturing job per well, rather than multi-stage. Since wells are often drilled in batches, the water required for hydraulic fracturing can be sourced from neighbouring wells that are being de-watered. The flow-back fluids recovered from the well are pumped to lined containment pits or tanks for treatment or offsite disposal.

Water use

The extent of water use and the risk of water contamination are key issues for any unconventional gas development and have generated considerable public concern. In the case of a shale gas or tight gas development, though some water is required during the drilling phase, the largest volumes of water are used during the hydraulic fracturing process: each well might need anything between a few thousand and 20 000 cubic metres (between 1 million and 5 million gallons). Efficient use of water during fracturing is essential. Average water use per well completion in the Eagle Ford play in west Texas has been reduced from 18.5 to 13.6 thousand cubic metres since mid-2010, primarily through increased recycling of waste water from flow-back of fracturing fluid, an important step forward, given that more than 2 800 drilling permits were issued by the Railroad Commission of Texas for Eagle Ford wells in 2011 (RCT, 2012).[11] The amount of water required for shale gas or tight gas developments, calculated per unit of energy produced, is higher than for conventional gas but comparable to the amount used for the production of conventional oil (Table 1.1).

Table 1.1 ▷ Ranges of water use per unit of natural gas and oil produced (cubic metres per terajoule)

	Water consumption	
	Production	Refining
Natural gas		
Conventional gas	0.001 - 0.01	
Conventional gas with fracture stimulation	0.005 - 0.05	
Tight gas	0.1 - 1	
Shale gas	2 - 100	
Oil		
Conventional oil*	0.01 - 50	5 - 15
Conventional oil with fracture stimulation*	0.05 - 50	5 - 15
Light tight oil	5 - 100	5 - 15

Source: IEA analysis.

* The high end of this range is for secondary recovery with water flood; the low end is primary recovery.

Note: Coalbed methane is not included in this table as it tends to produce water, rather than require it for production (but see below for the discussion of waste water disposal).

Water for fracturing can come from surface water sources (such as rivers, lakes or the sea), or from local boreholes (which may draw from shallow or deep aquifers and which may already have been drilled to support production operations), or from further afield (which generally requires trucking). Transportation of water from its source and to disposal locations can be a large-scale activity. If the hydraulic fracturing of a well requires 15 000 cubic metres, this amounts to 500 truck-loads of water, on the basis that a typical truck can hold around 30 cubic metres of water. Such transportation congests local roads, increases wear and tear to roads and bridges and, if not managed safely, can increase road accidents.

In areas of water-scarcity, the extraction of water for drilling and hydraulic fracturing (or even the production of water, in the case of coalbed methane) can have broad and serious environmental effects. It can lower the water table, affect biodiversity and harm the local

11. If these 2 800 wells each require 13.6 thousand cubic metres for well completion, the water requirement of 38 million cubic metres represents 0.2% of annual water consumption of the state of Texas, or 12% of the annual water consumption of the city of Dallas, Texas.

ecosystem. It can also reduce the availability of water for use by local communities and in other productive activities, such as agriculture.

Limited availability of water for hydraulic fracturing could become a significant constraint on the development of tight gas and shale gas in some water-stressed areas. In China, for example, the Tarim Basin in the Xinjiang Uyghur Autonomous Region holds some of the country's largest shale gas deposits, but also suffers from severe water scarcity. Although not on the same scale, in terms of either resource endowment or water stress, a number of other prospective deposits occur in regions that are already experiencing intense competition for water resources. The development of China's shale gas industry has to date focused on the Sichuan basin, in part because water is much more abundant in this region.

Hydraulic fracturing dominates the freshwater requirements for unconventional gas wells and the dominant choice of fracturing fluid for shale gas, "slick-water", which is often available at the lowest cost and in some shale reservoirs may also bring some gas-production benefits, is actually the most demanding in terms of water needs. Much attention has accordingly been given to approaches which might reduce the amount of water used in fracturing. Total pumped volumes (and therefore water volumes required) can be decreased through the use of more traditional, high viscosity, fracturing fluids (using polymers or surfactants), but these require a complex cocktail of chemicals to be added. Foamed fluids, in which water is foamed with nitrogen or CO_2, with the help of surfactants (as used in dish washing liquids), can be attractive, as 90% of the fluid can be gas and this fluid has very good proppant-carrying properties. Water can, indeed, be eliminated altogether by using hydrocarbon-based fracturing fluids, such as propane or gelled hydrocarbons, but their flammability makes them more difficult to handle safely at the well site. The percentage of fracturing fluid that gets back-produced during the flow-back phase varies with the type of fluid used (and the shale characteristics), so the optimum choice of fluid will depend on many factors: the availability of water, whether water recycling is included in the project, the properties of the shale reservoir being tapped, the desire to reduce the usage of chemicals and the economics.

Treatment and disposal of waste water

Waste water from hydraulic fracturing

The treatment and disposal of waste water are critical issues for unconventional gas production – especially in the case of the large amounts of water customarily used for hydraulic fracturing. After being injected into the well, part of the fracturing fluid (which is often almost entirely water) is returned as flow-back in the days and weeks that follow. The total amount of fluid returned depends on the geology; for shale it can run from 20% to 50% of the input, the rest remaining bound to the clays in the shale rock. Flow-back water contains some of the chemicals used in the hydraulic fracturing process, together with metals, minerals and hydrocarbons leached from the reservoir rock. High levels of salinity are quite common and, in some reservoirs, the leached minerals can be weakly radioactive, requiring specific precautions at the surface.[12] Flow-back returns (like waste water from drilling) requires secure storage on site, preferably fully contained in stable, weather-proof storage facilities as they do pose a potential threat to the local environment unless handled properly (see next section).

Once separated out, there are different options available for dealing with waste water from hydraulic fracturing. The optimal solution is to recycle it for future use and technologies are available to do this, although they do not always provide water ready for re-use for hydraulic fracturing on a cost-effective basis. A second option is to treat waste water at local industrial waste facilities capable of extracting the water and bringing it to a sufficient standard to enable it to be either discharged into local rivers or used in agriculture. Alternatively, where suitable geology exists, waste water can be injected into deep rock layers.

Box 1.4 ▷ What is in a fracturing fluid?

Environmental concerns have focused on the fluid used for hydraulic fracturing and the risk of water contamination through leaks of this fluid into groundwater. Water itself, together with sand or ceramic beads (the "proppant"), makes up over 99% of a typical fracturing fluid, but a mixture of chemical additives is also used to give the fluid the properties that are needed for fracturing. These properties vary according to the type of formation. Additives (not all of which would be used in all fracturing fluids) typically help to accomplish four tasks:

- To keep the proppant suspended in the fluid by gelifying the fluid while it is being pumped into the well and to ensure that the proppant ends up in the fractures being created. Without this effect, the heavier proppant particles would tend to be distributed unevenly in the fluid under the influence of gravity and would, therefore, be less effective. Gelling polymers, such as guar or cellulose (similar to those used in food and cosmetics) are used at a concentration of about 1%. Cross-linking agents, such as borates or metallic salts, are also commonly used at very low concentration to form a stronger gel. They can be toxic at high concentrations, though they are often found at low natural concentrations in mineral water.

- To change the properties of the fluid over time. Characteristics that are needed to deliver the proppant deep into subsurface cracks are not desirable at other stages in the process, so there are additives that give time-dependent properties to the fluid, for example, to make the fluid less viscous after fracturing, so that the hydrocarbons flow more easily along the fractures to the well. Typically, small concentrations of chelants (such as those used to de-scale kettles) are used, as are small concentrations of oxidants or enzymes (used in a range of industrial processes) to break down the gelling polymer at the end of the process.

12. These naturally occurring radioactive materials, or NORMs, are not specific to unconventional resources; some conventional reservoirs are also known to produce them.

- To reduce friction and therefore reduce the power required to inject the fluid into the well. A typical drag-reducing polymer is polyacrylamide (widely used, for example, as an absorbent in baby diapers).
- To reduce the risk that naturally occurring bacteria in the water affect the performance of the fracturing fluid or proliferate in the reservoir, producing hydrogen sulphide; this is often achieved by using a disinfectant (biocide), similar to those commonly used in hospitals or cleaning supplies.

Until recently, the chemical composition of fracturing fluids was considered a trade secret and was not made public. This position has fallen increasingly out of step with public insistence that the community has the right to know what is being injected into the ground. Since 2010, voluntary disclosure has become the norm in most of the United States.[13] The industry is also looking at ways to achieve the desired results without using potentially harmful chemicals. "Slick-water", made up of water, proppant, simple drag-reducing polymers and biocide, has become increasingly popular as a fracturing fluid in the United States, though it needs to be pumped at high rates and can carry only very fine proppant. Attention is also being focused on reducing accidental surface spills, which most experts regard as a more significant risk of contamination to groundwater.

Produced water from coalbed methane production[14]

In the case of coalbed methane, additional water supplies are rarely required for the production process, but the satisfactory disposal of water that has been extracted from the well during the dewatering process is of critical importance. The produced water is usually either re-injected into isolated underground formations, discharged into existing drainage systems, sent to shallow ponds for evaporation or, once properly treated, used for irrigation or other productive uses. The appropriate disposal option depends on several factors, notably the quality of the water. Depending on the geology of the coal deposit and hydrological conditions, produced water can be very salty and sodic (containing high concentrations of sodium, calcium and magnesium) and can contain trace amounts of organic compounds, so it often requires treatment before it can be used for irrigation or other uses. Using saline water for irrigation can inhibit germination and plant growth, while excessively sodic water can change the physical properties of the soil, leading to poor drainage and crusting and adversely affecting crop yields.

The potential cost of water disposal depends on both the extent to which treatment is required and the volume of water produced. In practice, the total amount of water that must be removed from each well to allow gas to be produced varies considerably. It can be very large; for example, an estimated 65 cubic metres of water (17 000 gallons) are

13. See the voluntary disclosure web site FracFocus (www.fracfocus.org).

14. Both conventional gas and other types of unconventional gas production can also be accompanied by produced water, but the flow rates involved are normally much smaller than for coalbed methane.

pumped from each coalbed methane well every day on average in the Powder River Basin in Montana and Wyoming. For the United States as a whole, it is estimated that, in 2008, more than 180 million cubic metres (47 billion gallons) of produced water were pumped out of coal seams (US EPA, 2010), equivalent to the annual direct water consumption of the city of San Francisco. In principle, produced water can be treated to any desired quality. This may be costly, but the treated water may have economic value for productive uses – as long as the cost of transporting the water is not excessive.

The options for treatment and disposal of produced water and the market value of water in the near vicinity are often key factors in the economics of coalbed methane developments. Many of the areas where coalbed methane is produced today, or where prospects for production are good, are arid or semi-arid and could benefit from additional freshwater supplies. For now, evaporation or discharge into drainage systems (in some cases, after treatment) are still the most common methods in North America (reuse of treated water is growing in Australia) because of the high cost of purifying the water for irrigation or reinjection into a deeper layer. In the United States, approximately 85 million cubic metres (22 billion gallons) of produced water, or about 45% of the total, were discharged to surface waters in 2008 with little or no treatment (US EPA, 2010).

There is limited experience of assessing the actual environmental impacts of produced water from coalbed methane production. A recent study by the US National Research Council found that the eventual disposal or use of produced water can have both positive and negative impacts on soil, ecosystems, and the quality and quantity of surface water and groundwater (NRC, 2010). Although the study found no evidence of widespread negative effects, allowance must be made for the fact that the industry is relatively young and that few detailed investigations into local impacts have been carried out yet.

The risk of water contamination

Significant concern has been expressed about the potential for contamination of water supplies, whether surface supplies, such as rivers or shallow freshwater aquifers, or deeper waters, as a result of all types of unconventional gas production. Water supplies can be contaminated from four main sources:

- Accidental spills of fluids or solids (drilling fluids, fracturing fluids, water and produced water, hydrocarbons and solid waste) at the surface.
- Leakage of fracturing fluids, saline water from deeper zones or hydrocarbons into a shallow aquifer through imperfect sealing of the cement column around the casing.
- Leakage of hydrocarbons or chemicals from the producing zone to shallow aquifers through the rock between the two.
- Discharge of insufficiently treated waste water into groundwater or, even, deep underground.

None of these hazards is specific to unconventional resources; they also exist in conventional developments, with or without hydraulic fracturing. However, as noted, unconventional developments occur at a scale that inevitably increases the risk of incidents occurring. Public concern has focused on the third source of potential contamination, *i.e.* the possibility that hydrocarbons or chemicals might migrate from the produced zone into aquifers through the intervening rock. However, this may actually be the least significant of the hazards, at least in the case of shale gas and tight gas production; in some cases a focus on this risk may have diverted attention, including the time of regulators, away from other more pressing issues.

Box 1.5 ▷ Coalbed methane production and effects on groundwater

There are concerns about the impact of coalbed methane production on groundwater flows and the supply and purity of water in aquifers adjacent to the coal seams being exploited. The extent to which this can occur is very location specific and depends on several factors, the most important of which are the overall volume of water initially in the coalbed and the hydrogeology of the basin; the density of the coalbed methane wells; the rate of water pumping by the operator; the connectivity of the coalbed and aquifer to surrounding water sources and, therefore, the rate of recharge of the aquifer; and the length of time over which pumping takes place.

In the United States, various agencies now monitor water in producing areas in order to learn more about this process. Depletion of aquifers because of coalbed methane production has been well-documented in the Powder River Basin: in the Montana portion of the basin, 65% to 87% recovery of coalbed groundwater levels has occurred after production ceased (NRC, 2010). However, the extent to which water levels in shallow alluvial and water table aquifers have dropped has not been measured (recent legislation in Queensland in Australia now requires such measurements to be performed). There is evidence that groundwater movement provoked by dewatering during coalbed methane production has increased the amount of dissolved salt and other minerals in some areas.

Because productive coal seams are often at shallower depths than tight or shale gas deposits, there is also a greater risk that fracturing fluids might find their way into an aquifer directly or via a fracture system (either a natural system or one that is created through fracturing). This risk is mitigated in part by the fact that, in contrast to shale or tight gas, the dewatering required for production of coalbed methane means that less water may be left in the ground in aquifers near the vicinity of the well, limiting the potential for contamination. As with shale or tight gas production, the flow-back fluids removed from the well after fracturing need to be treated before disposal.

The first hazard – the risk of spills at the surface – can be mitigated through rigorous containment of all fluid and solid streams. Accidents can always happen but good procedures, training of personnel and availability of spill control equipment can ensure they have a limited impact. As discussed below, greater use of pipelines to move liquids can reduce the risks associated with trucking movements.

Controlling the second hazard – leakage into a shallow aquifer behind the well casing – requires use of best practice in well design and well construction, particularly during the cementing process, to ensure a proper seal is in place, systematic verification of the quality of the seal and ensuring the seal does not deteriorate through the life of a well. This is a particular issue for wells in which multi-stage hydraulic fracturing is performed: the repeated cycles of high pressure pumping can apply repeated stress to the casing and to the cement column, potentially weakening them; selection of an appropriate strength of casing is therefore important.

The third hazard – leakage through the rock from the producing zone – is unlikely in the case of shale gas or tight gas because the producing zone is one to several thousand metres below any relevant aquifers and this thickness of rock usually includes one or several very impermeable layers. For example, the deepest potential underground sources of drinking water in the Barnett shale are at a depth of 350 metres, whereas the shale layer is at 2 000 to 2 300 metres. However, the hazard may be encountered if the producing zone is shallower or if there are shallow pockets of naturally occurring methane above the target reservoir. It is also theoretically possible if there are no identified impermeable layers in between or if deep faults are present that can act as a conduit for fluids to move from the deep producing zone towards the surface (such fluid movements are generally slow, but can occur on time scales of tens of years). One particular possibility is that hydraulic fractures may not be contained in the targeted rock layer and may break through important rock barriers or connect to deep faults. This is a rare occurrence because hydraulic fracturing is designed to avoid this (potentially costly) situation[15], but it cannot be completely excluded when the local geology is insufficiently understood.

Appropriate prior studies of the local geology to identify such situations are therefore a must before undertaking significant developments. Indeed, methane seeps to the surface have long been known (for example, the flame that has been burning for centuries in the village of Mrapen in Central Java, Indonesia, or the gas that fuels the "Eternal Flame Falls" in New York State, United States) and they have been used as a way to identify the presence of hydrocarbon deposits underground, showing that perfect rock seals do not always exist. On the other hand, the existence of seeps, and for that matter the presence of methane in many aquifers (Molofsky, 2011), shows that not all contamination is linked to industrial activity; it can also occur as a result of natural geological or biological processes.

15. This would increase losses of fracturing fluid and could mean in turn that the fracturing does not translate into the desired increase in gas production.

Addressing the fourth hazard – discharge of insufficiently treated waste water into groundwater or, even, deep underground – requires a regulatory response including appropriate tracking and documentation of waste water volumes and composition, how they are transported and disposed.

Methane and other air emissions

Shale gas and tight gas have higher production-related greenhouse-gas emissions than conventional gas. This stems from two effects:

- More wells and more hydraulic fracturing are needed per cubic metre of gas produced. These operations use energy, typically coming from diesel motors, leading to higher CO_2 emissions per unit of useful energy produced.
- More venting or flaring during well completion. The flow-back phase after hydraulic fracturing represents a larger percentage of the total recovery per well (because of more hydraulic fracturing, the flow-back takes longer and the total recovery per well is typically smaller due to the low permeability of the rock).

We have previously released estimates of these effects both in the case of flaring and for venting during flow-back, based on EPA data, in order to see what difference these practices make (IEA, 2011b). In the case of flaring, total well-to-burner emissions are estimated to be 3.5% higher than for conventional gas, but this figure rises to 12% if the gas is vented. Eliminating venting, minimising flaring and recovering and selling the gas produced during flow-back, in line with the Golden Rules, would reduce emissions below the lower figure given here.

Similar concerns about emissions attach to coalbed methane production, where significant volumes of methane can be vented into the atmosphere during the transition phase from dewatering to gas production and, where hydraulic fracturing is applied, during the well completion phase. Careful management of drilling, fracturing and production operations is essential to keep such emissions to a minimum.[16] This requires specialised equipment to separate gas from the produced water (and fracturing fluids) before injecting it into a gas-gathering system (or into temporary storage). If this is not possible for technical, logistical or economic reasons, it is preferable that the gas should be flared rather than vented for safety reasons and because the global-warming effect is considerably less.

The general issue of greenhouse-gas emissions from the production, transportation and use of natural gas, as well as the additional emissions from unconventional gas compared with conventional gas, has been the subject of some controversy. Some authors (Howarth, 2011) have argued that emissions from using natural gas as a source of primary energy have been significantly underestimated, particularly for unconventional gas. It has even been argued that full life-cycle emissions from unconventional gas can be higher than from

16. Coalbed methane production can reduce methane emissions if the gas would in any case have been released by subsequent coal-mining activities.

coal. The main issue revolves around methane emissions not only during production, but also during transportation and use of natural gas.

Methane is a more potent greenhouse gas than CO_2 but has a shorter lifetime in the atmosphere – a half-life of about fifteen years, versus more than 150 years for CO_2. As a result, there are different possible ways to compare the effect of methane and CO_2 on global warming. One way is to evaluate the Global Warming Potential (GWP) of methane, compared to CO_2, averaged over 100 years. The 4th Assessment report of the IPCC (IPCC, 2007) gives a value of 25 (on a mass basis) for this 100-years GWP, revised up from their previous estimate of 21. This value is relevant when looking at the long-term relative benefits of eliminating a temporary source of methane emissions versus a CO_2 source.

Averaged over 20 years, the GWP, estimated by the IPCC, is 72. This figure can be argued to be more relevant to the evaluation of the significance of methane emissions in the next two or three decades, which will be the most critical to determine whether the world can still reach the objective of limiting the long-term increase in average surface temperatures to 2 degrees Celsius (°C). Moreover, some scientists have argued that interactions of methane with aerosols reinforce the GWP of methane, possibly bringing it to 33 over 100 years and 105 over 20 years (Shindell, 2009): these recent analyses are under review by the IPCC. Such higher values would, of course, have implications not only for methane emissions from the gas chain but also for all other methane emissions, from livestock, landfills, rice paddies and other agricultural sources, as well as from natural sources (Spotlight).

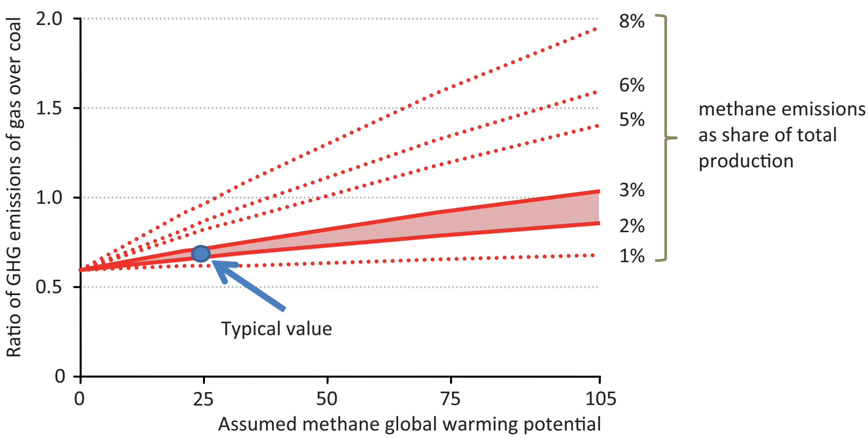
Methane emissions along the gas value chain (whether conventional or unconventional) come from four main sources:

- Intentional venting of gas for safety or economic reasons. Venting during well completions falls into this category, but venting can also take place as part of equipment maintenance operations.
- Fugitive emissions. These might be leaks in pipelines, valves or seals, whether accidental (*e.g*. corrosion in pipelines) or built into the equipment design (*e.g.* rotating seals, open tanks).
- Incidents involving rupture of confining equipment (pipelines, pressurised tanks, well isolation).
- Incomplete burning. The effectiveness of gas burning in gas flares varies according to wind and other conditions and is typically no better than 98%. (A similar effect can be seen when starting a gas stove: it can take a few seconds before a steady flame is established).

By their very nature, these emissions are difficult to quantify. Most estimates are based on emission factors for various parts of the chain (wells, various equipment, pipelines and so on), derived from studies conducted in the United States by the EPA and the Gas Research Institute in the 1990s (US EPA and GRI, 1996). It is by no means clear that these studies give a good indication for emissions in other parts of the world, or for the possible evolution of methane emissions in the future. Estimates of methane emissions from the gas chain at the global level vary between 1% and 8% of produced natural gas volumes (Howarth, 2011 and references therein; Petron, 2012; Cathles, 2012; Jiang 2011; and Skone 2011). The most comprehensive projections of future emissions, from the EPA (US EPA, 2011), assume no change in emission factors, for want of a better approach, and project a 26% increase in methane emissions from the oil and gas industry between 2010 and 2030.

Different assumptions about the level and impact of methane emissions can have a profound effect on the perception of gas as a "cleaner" fossil fuel. Figure 1.5 shows the well-to-burner emissions of natural gas compared to coal, as a function of various assumptions on GWP and average methane emissions. As seen from this figure, standard values (25 GWP, 2% to 3% methane emissions as a share of total production) substantiate the widely accepted advantage of gas, thanks to its lower combustion CO_2 emissions per unit of energy; but it is clear that more pessimistic assumptions can make gas a worse greenhouse-gas emitter than coal. It is very important that additional scientific work should pinpoint the most relevant GWP value and that efforts are redoubled to measure methane emissions more systematically.[17]

Figure 1.5 ▷ The impact of changing assumptions about methane on comparative well-to-burner greenhouse-gas emissions of natural gas versus coal



Note: Values below 1.0 on the vertical axis show points at which gas has lower well-to-burner emissions than coal. The comparison is for equivalent volumes of primary energy; however, gas also tends to be transformed, into other energy carriers (such as electricity) with higher efficiency than coal, so the ratio can be lower when calculated for the same end-use energy.

17. See, for example, a recent paper included in the Proceedings of the US National Academy of Sciences on methane leakage from natural gas infrastructure (Alvarez *et al.*, 2012)

One advantage attributable to expanded unconventional gas production and use over production and use of conventional gas is the distance to market; in general, unconventional resources are developed closer to the point of consumption, thereby reducing the distance required for transportation. All else being equal, this tends to reduce the level of fugitive emissions, as well as CO_2 emissions from the energy used for transportation.

SPOTLIGHT

How large are global methane emissions?

It is estimated that about 550 million tonnes (Mt) of methane (IPPC, 2007) are released into the atmosphere every year, but data on global methane emissions are poor. Converted into CO_2 equivalent (using the standard IPCC 100-years Global Warming Potential of 25), this amounts to about 14 gigatonnes CO_2-eq, roughly one-fourth of global greenhouse-gas emissions. Natural emissions (not related to man's activities) represent about 40% of total methane emissions. They come from natural seeps, wetlands, animals, such as termites, and vegetation decay. In addition, massive amounts of methane are stored in permafrost in Arctic regions and in underwater methane hydrates deposits. Some of this stored methane is released by natural processes, which are considered likely to accelerate with global warming: there is a risk of natural emissions increasing dramatically over the coming decades.

Non-energy related anthropogenic emissions come mostly from livestock, agriculture, landfills and wastewater. These represent about 38% of total methane emissions (64% of anthropogenic methane emissions). Energy-related methane emissions come from oil, gas and coal production, transportation, distribution and use as well as some biomass combustion: together they are estimated to be 125 Mt per year, about 20% of global methane emissions (36% of anthropogenic methane emissions). The gas and oil industry account for the lion's share of this: 70%, or 90 Mt per year, representing about 15% of total methane emissions (26% of anthropogenic emissions).

If current emissions are poorly known and the numbers above mere estimates, projecting future methane emissions is fraught with even more uncertainties. Natural emissions could be dramatically altered by the evolution of the climate. For anthropogenic emissions, activity levels in the energy and other industries as well as in livestock and agriculture can be projected, based on econometric analysis and assumptions on GDP and population growth, but the evolution of emission factors (volume of methane emitted per unit of activity) is very uncertain.[18] Many mitigation measures are considered to have low or even negative costs: reducing leaks in a gas

18. The IEA model (developed in collaboration with the OECD, using the ENV-linkages OECD model) uses the costs of mitigation measures (as derived from EPA studies; EPA, 2006) and a pseudo-price of carbon (whether coming from taxes, a carbon market or from regulations) to determine the likely evolution of emissions from an economic point of view. EPA has recently released draft updated costs of mitigation (EPA, 2012).

distribution system, for example, can allow more gas to be sold; the gas collected from a landfill can be marketed; changing the feed given to livestock to reduce methane production can allow more of the energy content of the feed to be transformed into marketable meat or milk. On the other hand, because of the very (spatially) distributed nature of most methane emission sources, it is not obvious that economic considerations alone will be sufficient to induce change. To achieve the trajectories of methane emissions consistent with the internationally agreed goal to limit the rise in global mean temperature to 2°C above pre-industrial levels, additional policy measures will be needed.

Golden Rules to address the environmental impacts

The outlook for unconventional gas production around the world depends critically on how the environmental issues described earlier are addressed. Society needs to be adequately convinced that the environmental and social risks will be well enough managed to warrant consent to unconventional gas production, in the interests of the broader economic, social and environmental benefits that the development of unconventional resources can bring. The Golden Rules, which are set out below with some explanatory background, suggest principles that can allow policy-makers, regulators, operators and others to address these environmental and social impacts in order to earn or retain that consent. We have called them Golden Rules because they can pave the way for the widespread and large-scale development of unconventional gas resources, boosting overall natural gas supply so as to realise a Golden Age of Gas (IEA, 2011b).

Abiding by these Golden Rules – or any rules – cannot reduce to zero the impacts on the environment associated with unconventional gas production. In any such undertaking, there are inevitable trade-offs between reducing the risks of environmental damage, on the one hand, and achieving the benefits that can accrue to society from the development of economic resources. In designing an appropriate regulatory framework, policy-makers need to set the highest reasonable social and environmental standards, assessing the cost of any residual risk against the cost of still higher standards (which could include the abandonment of resource exploitation). What is reasonable will evolve over time, as technology and industrial best practice evolve: in this spirit, these are not rigid rules, set in stone, but principles intended to guide regulators and operators. The format of regulation is also critical to achieving the intended result: it may include some specific and inflexible requirements but it should also encourage and reward performance to the highest standards, not supporting the notion that enough has been done if the instructions of others are mechanically observed, however meticulously. Ultimately, operators are responsible for the results of their operations. In framing these Golden Rules, we find that both governments and industry need to intensify their associated work if public confidence in this new industry is to be gained and retained.

Measure, disclose and engage

- ***Integrate engagement with local communities, residents and other stakeholders into each phase of a development, starting prior to exploration; provide sufficient opportunity for comment on plans, operations and performance, listen to concerns and respond appropriately and promptly.*** Simply providing information to the public is not enough; both the industry and the public authorities need to engage with local communities and other stakeholders and seek the informed consent that is often critical for companies to proceed with a development. Operators need to explain openly and honestly their production practices, the environmental, safety, and health risks and how they are addressed. The public needs to gain a clear understanding of the challenges, risks and benefits associated with the development. The primary role of the public authorities in this context is to provide credible, science-based background information that can underpin an informed debate and provide the necessary stimulus for joint endeavour between the stakeholders.
- ***Establish baselines for key environmental indicators, such as groundwater quality, prior to commencing activity, and continue monitoring during operations.*** This is a shared responsibility between the regulatory authorities, industry and other stakeholders. The data gathered needs to be made public and opportunities provided for all stakeholders to address any concerns raised, as an essential part of earning public trust. At a minimum, resource management or regulatory agencies must have groundwater quality information (and, for coalbed methane production, information on groundwater levels) in advance of new drilling activities, so as to provide a baseline against which changes in water level and quality can be compared.
- ***Measure and disclose operational data on water use, on the volumes and characteristics of waste water and on methane and other air emissions, alongside full, mandatory disclosure of fracturing fluid additives and volumes.*** Good data, measurement and transparency are vital to public confidence. For example, effective tracking and documentation of waste water is necessary to incentivise and ensure its proper treatment and disposal. Reluctance to disclose the chemicals used in the hydraulic fracturing process and the volumes involved, though understandable in terms of commercial competition, can quickly breed mistrust among local citizens and environmental groups.
- ***Minimise disruption during operations, taking a broad view of social and environmental responsibilities, and ensure that economic benefits are also felt by local communities.*** Existing legislation and regulations usually require operators to act in an environmentally and socially responsible manner, but operators need to go beyond minimally satisfying legal requirements in demonstrating their commitment to local development and environmental protection, for example through attention to local concerns about the volume and timing of truck traffic. Particularly in jurisdictions where mineral rights are owned by the state (rather than as in parts of the United States, where surface landowners might also be subsurface mineral rights holders,

entitled to royalty payments), it is essential that tangible benefits are evident at the local level, where production occurs. This can be difficult to achieve in a timely manner, given the delay between the start of a development project and the moment at which revenues start to flow, whether to government, the mineral rights' owner or the operator. Early public commitment by authorities and developers to expand local infrastructure and services in step with exploration and production activities can help. Governments need to be willing to consider using part of the revenues (from taxes, royalties, etc.) to invest in the development of the areas in question.

Watch where you drill

- ***Choose well sites so as to minimise impacts on the local community, heritage, existing land use, individual livelihoods and ecology.*** The choice of well site is a moment when engagement with local stakeholders and regulators needs to be handled with the utmost care. Each well site needs to be chosen based on the subsurface geology, but also taking into consideration populated areas, the natural environment and local ecology, existing infrastructure and access roads, water availability and disposal options and seasonal restrictions caused by climate or wildlife concerns. Sensitivity at this stage to a range of above-ground concerns can do much to mitigate or avoid problems later in a development.
- ***Properly survey the geology of the area to make smart decisions about where to drill and where to hydraulically fracture: assess the risk that deep faults or other geological features could generate earthquakes or permit fluids to pass between geological strata.*** Careful planning can greatly improve the productivity and recovery rates of wells, reducing the number of wells that need to be drilled and minimising the intensity of hydraulic fracturing and the associated environmental impact. Although the risk of triggering an earthquake is small, even minor earth tremors can easily undermine public confidence in the safety of drilling operations. A careful study of the geology of the area targeted for drilling is necessary to allow operators to avoid operations in areas where deep faults or other characteristics create higher risks. Producers also need to survey for the presence of old boreholes or naturally occurring methane in shallow pockets above the source rock and adjust drilling sites (or the pathway of the wellbore) to avoid these areas.
- ***Monitor to ensure that hydraulic fractures do not extend beyond the gas-producing formations.*** The risk of leakage of the fracturing fluid used for shale and tight gas production through the rock from the producing zone into aquifers is minimal because the aquifers are located at much shallower depths; but such migration is theoretically possible in certain exceptional circumstances (described in the preceding section). A good understanding of the local geology and the use of micro-seismic (or other) measuring techniques for monitoring fractures is necessary to minimise the residual risk.

Isolate wells and prevent leaks

- ***Put in place robust rules on well design, construction, cementing and integrity testing as part of a general performance standard that gas bearing formations must be completely isolated from other strata penetrated by the well, in particular freshwater aquifers.*** Regulations need to ensure wells are designed, constructed and operated so as to ensure complete isolation. Multiple measures need to be in place to prevent leaks, with an overarching performance standard requiring operators to follow systematically all recommended industry best practices. This applies up to and including the abandonment of the well, *i.e.* through and beyond the lifetime of the development.
- ***Consider appropriate minimum-depth limitations on hydraulic fracturing to underpin public confidence that this operation takes place only well away from the water table.*** Alongside measures to ensure that wells are designed, built and cemented to a high standard, the regulator may choose to define an appropriate depth limitation for shale and tight gas wells, based on local geology and any risk of communication with freshwater aquifers, above which hydraulic fracturing is prohibited.
- ***Take action to prevent and contain surface spills and leaks from wells, and to ensure that any waste fluids and solids are disposed of properly.*** This requires both stringent regulations and a strong performance commitment by all companies involved in drilling and production-related activities to carry out operations to the highest possible standard. Good procedures, training of personnel and ready availability of spill-control equipment are essential to prevent and limit the impact of accidents if they do occur. Upgrading fluid-disposal systems so that storage and separation tanks replace open pits (closed-loop systems) can reduce the risk of accidental discharge of wastes during drilling.

Treat water responsibly

- ***Reduce freshwater use by improving operational efficiency; reuse or recycle, wherever practicable, to reduce the burden on local water resources.*** Regulations covering shale and tight gas production (coalbed methane operations are net producers of water) need to be designed to encourage operators to use water efficiently and to reuse and recycle it. The largest volumes of water are required for hydraulic fracturing: where the necessary economies of scale are present, it should be feasible to reuse and recycle significant volumes of the flow-back water from fracturing operations, reducing the issues and costs associated with truck traffic and with securing water supplies and wastewater disposal.
- ***Store and dispose of produced and waste water safely.*** Within an overarching performance framework, rigorous and consistent regulations are needed to cover safe storage of waste water, with measures to ensure the robust construction and lining of open pits or, preferably, the use of storage tanks. Technology exists to treat produced and waste water to any standard, with the cost varying accordingly. It is

the responsibility of regulators to set and enforce appropriate standards based on local factors, including the availability of freshwater supplies and options for disposal, without diminishing the operators' ultimate responsibility for operation in accordance with evolving best practice standards. The least-cost solution for producers may not be the most economically optimal solution, when the potential long-term benefits of using treated water and the wider social and environmental costs of discharges into water courses or evaporation ponds are taken into consideration.

- ***Minimise use of chemical additives and promote the development and use of more environmentally benign alternatives.*** Disclosure of fracturing fluid additives can and should be compatible with continued incentives for innovation. The industry should commit to the development of fluid mixtures that, if they inadvertently migrate or spill, do not impair groundwater quality, or adopt techniques that reduce the need to use chemical additives.

Eliminate venting, minimise flaring and other emissions

- ***Target zero venting and minimal flaring of natural gas during well completion and seek to reduce fugitive and vented greenhouse-gas emissions during the entire productive life of a well.*** Best practice is to recover and market gas produced during the completion phase of a well, and public authorities need to consider imposing restrictions on venting and flaring and specific requirements for installing equipment to help minimise emissions. Measures in this area will also lower emissions of conventional pollutants, including VOCs. Operators should consider setting targets on emissions as part of their overall strategic policies to win public confidence that they are acting to minimise the environmental impact of their activities, taking into account the financial benefits of commercialising the gas that would otherwise be vented or flared. The gas industry as a whole, including conventional gas producers and companies operating in the midstream and downstream, needs to demonstrate that they are just as concerned by methane emissions beyond the production stage, for example in transportation and distribution.
- ***Minimise air pollution from vehicles, drilling rig engines, pump engines and compressors.*** Pollution from vehicles and equipment is often controlled by existing environmental and fuel-efficiency standards (it is a responsibility of governments to ensure that appropriate standards are in place). Operators and service providers should consider the advantages of deploying the cleanest vehicles and equipment available, for example, electric vehicles and gas-powered rig engines, to reduce both local air and noise pollution.

Be ready to think big

- ***Seek opportunities for realising the economies of scale and co-ordinated development of local infrastructure that can reduce environmental impacts.*** Investments in infrastructure to reduce environmental impacts that may be commercially impossible to justify for an individual well can be justified for a larger development. Good regulation can help to realise these gains by ensuring appropriate spatial planning of licensing areas and of the associated infrastructure (such as access roads, water resources and disposal facilities, gas processing units, compression stations and pipelines). The concept of utility corridors and multi-use rights of way can be useful to concentrate infrastructure development and so limit the wider environmental impacts. Operators can realise these gains in various ways, for example by drilling multiple wells from a single pad (with horizontal bores tapping different parts of the reservoirs): this may result in greater disruption in the immediate vicinity of the site but can significantly reduce the wider environmental footprint. Another example is the construction of a pipeline network for water that requires upfront investment but obviates the need for many thousands of truck movements over the duration of a project and can lower unit costs.[19] Good project and logistical planning by operators needs to go hand-in-hand with early strategic assessments and timely interventions by public authorities.
- ***Take into account the cumulative and regional effects of multiple drilling, production and delivery activities on the environment, notably on water use and disposal, land use, air quality, traffic and noise.*** Development of any hydrocarbon resource involves a large amount of activity to build the necessary infrastructure, bring in supplies, drill wells, extract the resource, process it and transport it to market. This activity is enhanced for unconventional developments, because of the larger number of wells required. As a result, the level of activity that might be tolerable for individual wells, such as volumes of road traffic, land and water use or noise from drilling activity, can increase by orders of magnitude. Regulators need to assess the cumulative impact of these effects and respond appropriately. Assessment on a regional basis is particularly important in the case of water requirements.

19. See the next sub-section for an assessment of the impact of such infrastructure developments on project costs; this is also covered in a recent paper on water management economics for shale gas developments (Robart, 2012).

Ensure a consistently high level of environmental performance

- ***Ensure that anticipated levels of unconventional gas output are matched by commensurate resources and political backing for robust regulatory regimes at the appropriate level, sufficient permitting and compliance staff, and reliable public information.*** An important focus for governments should be on ensuring there is a sufficient knowledge base on all environmental and technical aspects of unconventional gas development, that high-quality data are available and that sound science is being applied and promoted. Well-funded, suitably skilled and motivated regulators, in sufficient numbers, are essential to the responsible development of an unconventional resource.
- ***Find an appropriate balance in policy-making between prescriptive regulation and performance-based regulation in order to guarantee high operational standards while also promoting innovation and technological improvement.*** In some areas, detailed rules and checks are indispensable to guarantee environmental performance; but it is not always possible, or desirable, to regulate every aspect of a process in which technology is moving rapidly. Setting performance criteria and allowing operators to find the best way to meet them can often provide a better outcome than a prescriptive approach. Examples of performance criteria might be a mandated minimum level of improvement in water usage or a requirement that a "best-in-class" cement quality measurement is run, the burden being on the operator to prove the use of best-in-class. Whichever approach or combination of methods is chosen, there needs to be strict enforcement and penalties in the case of non-compliance, ultimately including loss of the licence to operate.
- ***Ensure that emergency response plans are robust and match the scale of risk.*** Operators and local emergency services should have robust plans and procedures in place to respond quickly and effectively to any accident, including appropriate training and equipment.
- ***Pursue continuous improvement of regulations and operating practices.*** Technology and best practice are constantly evolving. While respecting the advantages of clarity and stability in regulation, governments must be ready to incorporate lessons learned from experience in a dynamic industrial sector. For industry, following best practice means constant readiness to raise standards and providing the means to meet them.
- ***Recognise the case for independent evaluation and verification of environmental performance.*** Credible, third-party certification of industry performance can provide a powerful tool to earn and maintain public acceptance, as well as providing a powerful tool to assist companies to adhere to best practices. These independent assessments should come from institutions that enjoy public trust, whether academic or research institutes or independent regulatory or certification bodies.

Complying with the Golden Rules

Application of these Golden Rules requires action to be taken by both governments and industry. While the ultimate responsibility for sustaining public confidence rests with the industry, it is governments that that need to set the regulatory framework, promulgate the required principles and provide support through many related activities, *e.g.* scientific research. Trying to specify precisely the roles of governments, gas producers and other private sector operators in each area is not practicable on a global scale. Conditions vary from country to country, including the legal, geological, social and political background, farming/land-use practices, water availability and many others.[20] But the general principles are clear and, in the sections that follow which examine the implications of the Golden Rules for governments and for industry, we have included some observations on the allocation of responsibilities between the public authorities and operators.

Implications for governments

Ensuring responsible development of unconventional gas resources, in line with these Golden Rules, puts substantial demands on policy-makers and regulators. First and foremost, the intensive nature of unconventional gas developments – and the scope for rapid growth in unconventional supply discussed in Chapter 2 – means that existing regulatory arrangements may have to be revised and licensing, compliance and enforcement staff reinforced. The need for new regulatory bodies may need to be considered or, more likely, existing ones may require new resources, functions and powers. This reinforcement of capacity needs to anticipate the expansion of industrial activity, so an appropriate regulatory regime is in place in good time. In keeping with regulatory best practice, such regulators will need to be independent of industry (although this certainly does not exclude ongoing consultation with industry), and have the right (often new) skills and funding. Scope exists to secure the necessary funding from industry in advance of development, for example through fees attached to the award of exploration rights.

The overarching challenge for policy-makers, to find the right balance between the need to minimise adverse environmental and social impacts while encouraging the responsible development of resources for the benefit of the local and national economy, will require judgement at the highest political level. Once that judgement is made, operational decisions of considerable weight remain to be made, for example as to the level of detail required in regulating industry operations – detailed or prescriptive provisions may be necessary, but they can also deny legitimate scope for operators to minimise costs and can impose onerous monitoring and enforcement responsibilities on regulators; performance-based regulation can work better in many areas, particularly for an industry in which technology is changing quickly.

20. Examples of regulation and best practice, from different countries, in areas covered by these Golden Rules are available on the IEA website at http://www.worldenergyoutlook.org/goldenrules.

In a number of jurisdictions, significant advances have been made in regulatory arrangements in recent years. However, the situation is very dynamic and industry has the capacity to expand rapidly; governments in resource-rich areas need to act quickly to anticipate future needs and to put the necessary measures in place. The challenge for governments and regulators can be acute in relation to water resources and the risk of water contamination. Rigorous data collection, assessment and monitoring of water requirements (for shale and tight gas), and measurement of the quality of produced water (for coalbed methane) and of waste water (in all cases) are needed to allow informed decisions to be made. Existing users are deeply suspicious that their rights and water availability might be compromised. There is a need, among other things, for transparent, speedy and equitable procedures for compensating existing users who suffer loss.

Box 1.6 ▻ Getting the market setting right

Alongside attention to environmental issues, there are many other policy areas that affect the prospects for unconventional gas development, including: the terms for access to resources; clarity on mineral rights; a consistent fiscal and overall investment framework; the provision of infrastructure; and the structure and regulatory framework in a given market (see also the assumptions underpinning the projections in Chapter 2). Market developments are at varying stages in different countries and regions. North America has well-functioning gas markets and, to take one example, many observers consider reliable third-party access to pipelines has been a pivotal part in its unconventional gas development by giving gas producers confidence that their new gas output will be able to reach market. Other key supportive market or regulatory conditions for gas production (both conventional and unconventional) include: the removal of wellhead price controls; the absence of undue restrictions on trade and export; a competitive upstream environment that encourages innovation; and efficiency and market-based pricing for gas. While these market conditions have been under discussion for many years in most OECD jurisdictions, implementation of the necessary reforms remains at best incomplete; and the challenges are greater in many non OECD countries.

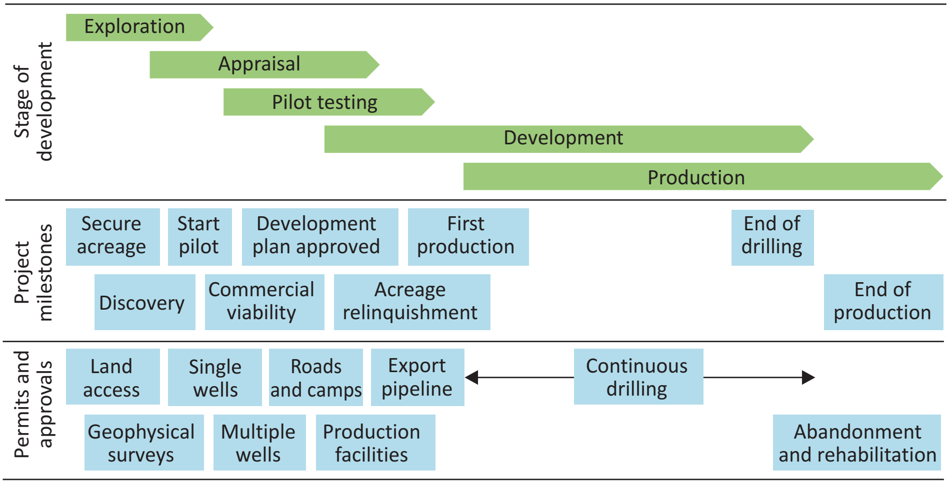
Governments everywhere have a central role in ensuring a sound, scientific, credible, knowledge base is publicly available prior to widespread development. Policy-makers and regulators themselves need access to the necessary expertise in order to understand and mitigate the environmental risks.[21] Baselines for various indicators, water in particular, are critical in this regard, but this requirement also encompasses basic geological and geophysical information. Good quality data are essential, not just as an input to good

21. An example is the decision of the Australian Government in late 2011 to establish an expert Scientific Committee, funded with AUD 150 million ($150 million) over four years, to oversee regional assessments and research on water-related impacts in areas where coalbed methane developments are proposed.

policy-making, but also to make it possible to demonstrate that the regulatory system is functioning effectively and to identify areas where improvements are needed.

Within large federal systems (for example the United States, Canada and Australia) environmental powers are usually exercised at state or provincial level, facilitating approaches that respond to local factors, such as the geology, the chosen technology and specific environmental risk factors. Local social and environmental concerns are often best dealt with at local levels. Clarity is often required as to the division of responsibilities between different levels of government, with the national authorities responsible for ensuring reasonable consistency of regulation and that adequate funding is available for region-wide work (for example, in river systems that cross internal or international boundaries).

Figure 1.6 ▻ Stages in an unconventional gas development



Note: The stages, milestones and permits shown here are not unique to unconventional developments, but the distinctive element is the overlap between stages of development, as opposed to a more sequential pattern for a typical conventional project.

Differences between the way in which conventional and unconventional resources are developed need to be taken into account in designing an effective legal and regulatory system. Conventional oil and gas developments generally follow a fairly well-defined sequence, but the distinctions between the phases of an unconventional development can be much less clear-cut – development generally proceeds in a more incremental fashion (Figure 1.6).[22] At any given time an operator may be exploring or appraising part of a

22. Often, the initial question is not whether the unconventional resource exists but whether the gas or liquids can be produced in a particular location at economic flow rates. Whereas each appraisal well of a conventional reservoir tends to increase knowledge about the overall reservoir structure and its limits, it is much more difficult with an unconventional play to extrapolate the results of individual appraisal wells to the acreage as a whole.

licence area, developing another part and producing from a third, with different regulatory approvals and permits applying at each stage. The blurred lines between the stages of an unconventional resource project development increase the complexity of the interactions between operator and regulators (and between the operator and local communities) throughout the life cycle of the development. For example, the regulatory system in most jurisdictions requires the submission and approval of a detailed field development plan at the end of the exploration phase. However, the longer learning curve for unconventional plays makes it much more difficult to develop comprehensive plans at this stage, with the risk that relatively small subsequent alterations might trigger the need to resubmit and re-approve the entire development plan – a lengthy and burdensome process for both sides.

Beyond their focus on the proper construction of individual wells and installations, regulators also need to take a broader view of the impact of multiple projects and wells over time. This broader scope is essential when it comes to assessments of water use and disposal and of future water requirements, but can be also required in other areas, including land use, air quality, traffic and noise. In general, a regulatory system that focuses primarily on well-by-well approvals rather than project level authorisations, can fail to provide for some environmental risks and miss opportunities to relieve them. For example, there are investments in infrastructure that may not proceed for an individual well but which would serve appreciably to reduce the cumulative environmental impacts of large-scale development, such as centralised water treatment plants or pipeline networks for water supply or removal (see below). One of the ways that a regulatory framework can facilitate this sort of investment is through issuing licences for sufficiently large areas and durations.

Governments are usually instrumental in promoting the co-ordinated and timely expansion of regional infrastructure alongside a gas development, including either directly putting in place alternatives to road transportation or ensuring that the regulatory framework serves to encourage or require the construction of gas transportation capacity or an expansion of local power supply. Either way, strong co-ordination and communication is necessary between different branches and levels of government, as the rapid growth of a new industry puts pressure not only on the local physical infrastructure, but also on local social services.

Implications for industry

All parts of the unconventional gas industry have to contribute to proving to society that the benefits of unconventional gas development more than offset the costs in social and environmental terms. This entails, among other things, demonstrating that environmental and social risks are being properly addressed at all stages of a development: adoption and application in full of these Golden Rules is one way to support and accelerate this process. Elements of these Golden Rules are already being applied today, incorporated into best practice or embodied in regulation. The challenge is to ensure that the highest reasonable standards are in place and are applied and enforced in a consistent and credible way across the industry. Companies have to convince society that they have both the interest and the incentive to constantly seek ways of improving their performance.

There is a cost entailed. Compliance with these Golden Rules can in many cases increase the overall financial cost of development. How much will vary, depending on the starting point and on how each jurisdiction formulates its rules but, based on our analysis of the impact on the costs of a typical 2011 shale gas well (presented below), the additional costs are likely to be limited. For a single well, application of the Golden Rules can add around 7% to the overall cost of drilling and completion. The increase in costs could be significantly lower when considered across a full development project, as additional upfront capital costs incurred to reduce environmental impacts can, in many cases, be offset by lower operating costs.

Major cost elements in a shale gas well

The major cost elements in the drilling and completion of a shale gas well are the rig and associated drilling services, and the hydraulic fracturing stage of well completion. Well construction costs are primarily influenced by the geographical location, the well depth and, to some extent, reservoir pressure, and by the market and infrastructure conditions in the country or region under consideration. For example, a typical onshore shale gas well in the Barnett shale in Texas may currently cost $4 million to construct, while a similar well in the Haynesville shale costs twice as much, because of the depth and pressure. A similar well in Poland might cost $10 million to $12 million, because the current size of the market means that the drilling and service industry is much less developed in Poland than in the United States.

In general, more technical services are required during drilling and completing a shale or tight gas well than for a similar onshore conventional gas well, which makes it more expensive. The cost of multi-stage hydraulic fracturing can add anything between $1 million and $4 million to the construction costs of a well in the United States, depending on location, depth and the number of stages. In a shale reservoir, when drilling a well with a long lateral section, roughly 40% of the total cost goes toward the drilling and associated hardware and the remaining 60% to well completion, of which multi-stage hydraulic fracturing is the largest component. In a conventional well, the completion cost would be only about 15% of the overall well cost.

Break-even costs of shale-gas production in the United States have fallen sharply in recent years, thanks to an increase in the proportion of horizontal wells, the length of horizontal sections and the number of hydraulic fracturing stages per well, as well as the benefits of ever-better knowledge and experience of the various resource plays. The share of horizontal wells in the total number of shale-gas wells drilled increased from less than 10% in 2 000 to well over 80% today. Over the same period, the average length of the lateral sections has increased from around 800 metres to well over 1 200 metres and the typical number of hydraulic fracturing stages has risen from single figures to around 20.[23]

Operational costs, similarly, vary with local conditions: for example, just as for drilling, operating costs in Europe are expected to be 30% to 50% higher than in the United States for a similar shale gas operation. Dry gas requires less processing than wet gas (gas containing a small fraction of liquid hydrocarbons), but also has lower market value, particularly in the current context of very high oil-to-gas price ratios in some markets.

It is worth noting that two of the key subsurface drivers of well cost – depth and well pressure – are expected to be higher in many of the areas being explored outside North America. On the other hand, for all unconventional deposits, there is considerable potential for cost savings through organising development so as to exploit economies of scale, learning, and optimising well selection and locations for hydraulic fracturing.

Impact on the cost of a single well

The typical shale gas well that we use as a basis for this analysis is not a "worst case" but rather a well of the type that was regularly drilled in 2011 into deep shale reservoirs (such as the Haynesville and Eagle Ford shale plays) in the United States, taking in many industry best practices that were not always systematically followed in the previous decade. The well is assumed to reach a vertical depth of the order of 3 000 metres, have a horizontal section of around 1 200 metres and be completed with 20 fracture stages using a total of 2 000 tonnes of proppant and 15 000 cubic metres of water (requiring 500 trucks). This type of well would typically be drilled in three sections of successively smaller diameter, each one being lined with steel casing and cemented in place before the next section is drilled.[24] The well considered is a development well rather than an exploratory well.

Such a well might be expected to cost $8 million, take a month to drill and a further month to complete. The hydraulic fracturing process accounts for around 40% of the total well cost – around twice as much as the second most expensive item, the rig itself. By comparison, a typical onshore conventional vertical gas well in the same area would cost around $3 million, with 40% being spent on the rig.

23. Some wells have lateral sections reaching up to 3 000 metres in length, with up to 40 individual geological zones for hydraulic fracturing, carried out one at a time. However, there are practical mechanical limits to the length of horizontal sections and multi-stages due to the pressure and temperature effect on the casing which mean that laterals longer than 1 800 metres or more than 20 fracture stages carry more mechanical risk (Holditch, 2010).

24. Since the well being considered already had two barriers over the shallow aquifer region with hydrocarbons being produced through production tubing, we did not include an additional casing string in our calculation of the additional costs of compliance.

Applying the Golden Rules to this well would be expected to have the following effects on costs, summarising various elements of the Rules under four indicative headings:

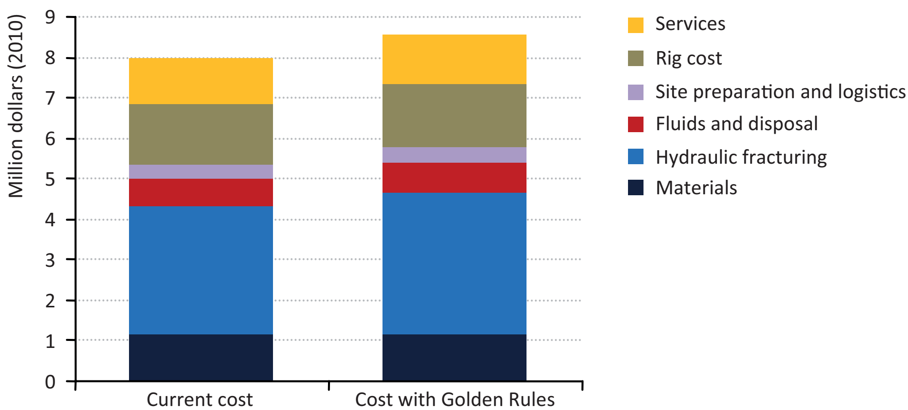
- **Isolate wells and prevent leaks:** measures in this area could include increased spending on cement design, selection and verification, coupled with a slight increase in drilling time to ensure the quality of the well-bore and provide a contingency for remedial cementing, if required. For the purposes of our analysis, we have assumed that the cement would be designed to withstand all expected stresses over the life span of the well, including the stresses induced during the 20 stages of hydraulic fracturing. The well would be drilled with appropriate tools and mud to produce a smooth and regular well-bore, to ensure that the cement bonds tightly with the wall of the well. Flexible cements or cements incorporating other technical advances that give better performance against the design criteria would be used. The cement would be pressure-tested and measurements taken to validate the quality of the cement bond on the exterior casing wall, with a contingency for remedial work if required. The American Petroleum Institute (API) publishes comprehensive standards and best practices pertaining to the construction of wells to ensure their integrity so that they are leak-free. In our analysis, 10% was estimated as the increment to drilling and cementing service costs needed to take account of these measures.
- **Eliminate venting, minimise flaring and other emissions:** this could be achieved by installing separator equipment for the hydrocarbons when they are brought to surface. For the purposes of our analysis, we have estimated a 10% addition to the cost of services required during the flow-back phase (but have not assumed that it is offset by sales of the recovered oil or gas[25]).
- **Treat water responsibly:** measures in this area could involve upgrading of fluid-disposal systems to ensure zero discharge at any stage and maximum re-use of water, as well as the use of green fracturing fluids with minimum chemical additives. In our analysis, 10% has been added to the cost of hydraulic fracturing on this basis, and a further 10% to the cost of rig fluids and disposal.
- **Disclose and engage:** responsiveness to local community concerns might involve reducing the noise from rig operations by cladding the rig with sound-proof material or imposing trucking restrictions at times at which they would otherwise cause greatest local disturbance or risk of accident. $20 000 has been added to the rig cost to cover sound-proofing of the rig and 10% to the logistics cost to cover some trucking restrictions.

In addition to these measures, we have included other actions that would add little to the cost of operations but would increase understanding of the environmental impact of shale-gas operations and facilitate dialogue with stakeholders. Simple measurement of airborne

25. According to the US EPA (EPA, 2011), general adoption of this type of “green completion” could also cut emissions of VOCs from new hydraulically fractured gas wells by 95%. The EPA further estimates that operators could expect to recover the additional cost associated with green completions within 60 days through the sale of captured hydrocarbons.

emissions at well sites in a consistent manner would provide valuable information to narrow the uncertainty around the extent of fugitive emissions of methane. Similarly, tests of local water wells that draw from an aquifer being drilled through would determine if there was contamination from any source. In total, we estimate that all the measures listed above would add around $580 000, or 7%, to the overall cost of drilling and completing this shale-gas well (Figure 1.7).

Figure 1.7 ⊳ Impact of the Golden Rules on the cost of a single deep shale-gas well



Notes: Materials include all tangible material that is used in the well construction and remains in the well when it is completed, such as steel casing, valves and plugs.

Services include various services, other than hydraulic fracturing services, that are used in well construction: directional drilling services, cementing services, casing services, wire line and testing services.

Source: IEA analysis.

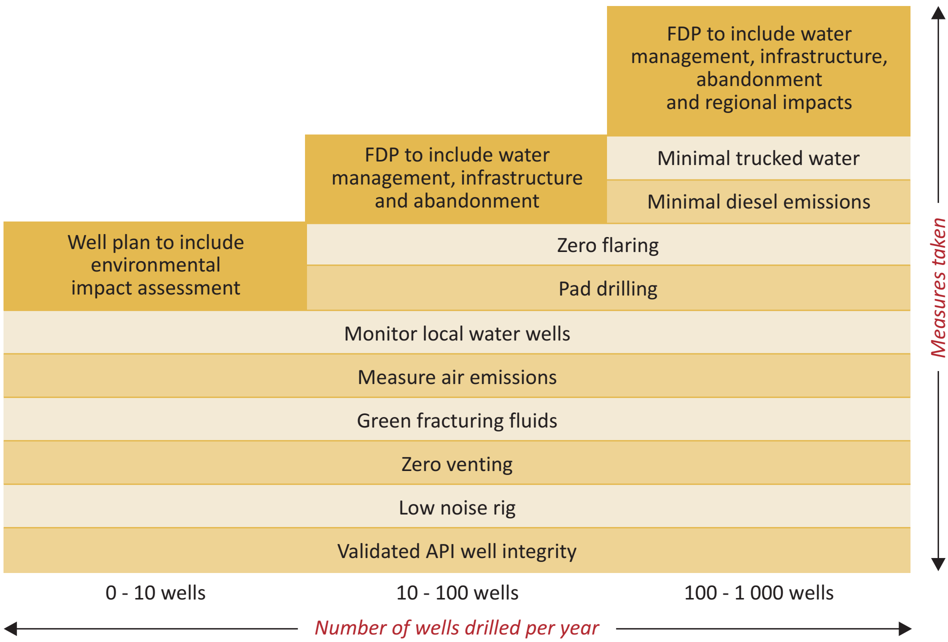
Impact on larger-scale developments

In practice, within a single licensing area, each operator typically drills a large number of wells at different sites. Applying the Golden Rules to entire unconventional gas developments could diminish the impact on overall production costs, because of economies of scale. While many of the environmental impacts discussed earlier in this chapter demand action chiefly where the scale of operations is large, large-scale operations also provide opportunities to minimise or eliminate environmental risks by optimising the process of drilling and completing each well. As the size of a development increases, measures to reduce environmental effects become both necessary and economically feasible (Figure 1.8), in a way that may not be possible for a single well.[26] In the case of gas, water and potentially

26. Many best practices can and should be applied to all wells, regardless of the size of the development. However, practices such as pad drilling, zero flaring and the minimisation of diesel emissions or trucked water involve the installation of infrastructure that, as well as not being cost effective, might even cause more environmental disruption if serving only single wells. For example, the number of truck journeys required to install water pipelines to a single isolated well would probably be more than the number of truck journeys required for the water itself.

electricity networks, greater upfront capital expenditure is required, but operating costs can be reduced, leaving the overall economics of a large-scale development no worse and in some cases improved.

Figure 1.8 ▷ Indicators of best practice as unconventional gas developments grow in size



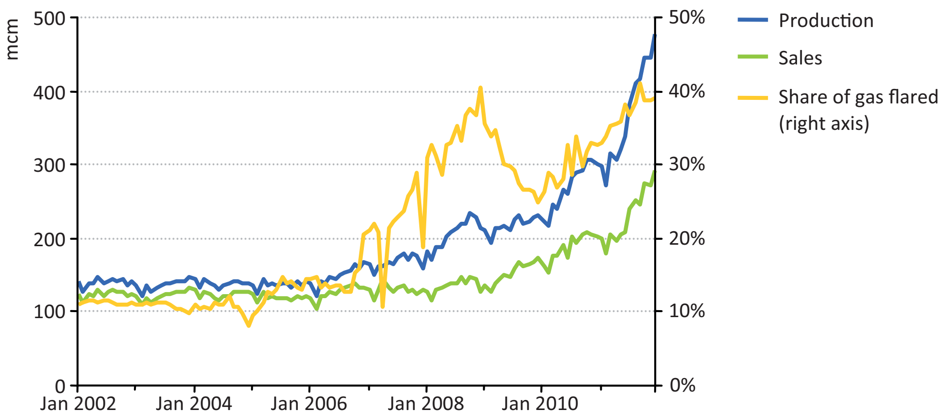
Notes: FDP = Field Development Plan; API = American Petroleum Institute Standards.

A well thought-out field development plan, based on a thorough environmental impact assessment, can help to capture these economies of scale and ensure that the hazards are well identified and that preventative or mitigating measures are in place. A key assumption in our analysis is that operators are able to plan developments optimally, both in space and in time. For this, licensing areas need to be large enough and be held for periods that are long enough for efficient development planning and the sharing of infrastructure. This needs a supportive regulatory framework.[27] Realising these gains also tends to rely on early investment in project infrastructure, often before production comes on stream and revenues start to flow: this can be a constraint for smaller companies, particularly where they are investing in marginal developments.

27. In certain regions of the United States, this is not possible due to smaller acreage blocks and lease expiration acting as a driver for development planning.

Good logistics and project planning is essential, both from the industry and from the public authorities, in view of the envisaged scale of a development. It is particularly important that infrastructure development keeps pace with upstream activity as the consequences of failure to do so can fall on the environment. For example, Figure 1.9 illustrates how the rapid development of light tight oil production in the Bakken shale was accompanied by a rise in the flaring of associated gas, as the necessary increase in gas transport infrastructure did not occur at the same pace as the increase in drilling.

Figure 1.9 ▷ Monthly natural gas production and flaring in North Dakota



Source: North Dakota Mineral Resources Department.

For the purposes of our analysis of the implications of applying the Golden Rules at scale, we considered a development of 120 wells per year.[28] In order to be able to plan and implement the types of measures described in Figure 1.8, the licensing area would need to comprise contiguous blocks and be held for at least a ten-year period, with freedom to develop according to the best environmental plan (rather than drilling to retain leases or avoid relinquishment clauses).

For this scale of development, we envisaged the following:

- **Zero venting or flaring of gas at all stages of operations:** this would require the installation of test equipment and gas-gathering infrastructure before any wells are completed. The scale of operation would mean that it would be economically viable to have this equipment dedicated to the development, although it remains challenging to estimate expected production rates with sufficient accuracy to ensure that the infrastructure is correctly sized. The early installation of gas-gathering infrastructure would bring forward capital expenditure, but would not increase the net cost, as any additional charges, including interest charges, would probably be offset by the value of the gas captured. *Estimated cost impact on a large-scale development: neutral.*

28. We considered ten rigs drilling eight wells from each pad, where the drilling phase of each well lasts 30 days, including the rig move. Thus, each rig would move every eight months to a new pad location.

- **Zero in-field trucking of water within the concession area:** this is an area where regulation and licensing requirements can play an important role. If these facilitate the necessary investment, capital expenditure on building water supply pipelines could be offset over the ten-year period by the reduction in truck movements. *Estimated cost impact: neutral.*
- **Central purpose-built water-treatment facilities:** these facilities, allowing closed-loop recycling of waste water, could be linked by pipeline to each pad location. They would reduce the overall water supply required for operations and minimise the need for off-site disposal, thereby reducing total transportation, water and disposal costs. Based on industry case studies, *we estimate savings at $100 000 to $150 000 per well*.
- **A long-term monitoring program for the development:** this could take different forms but might include performing a 3-D seismic survey over the licensing area before drilling commences to establish a geological baseline for the location of faults and sweet spots, as well as the temporary or permanent installation of micro-seismic monitoring to monitor seismic events and the propagation of fractures, and the installation of equipment to monitor the quality of water in aquifers that are being drilled through. *We estimate the additional cost of these three measures at between $100 000 and $150 000 per well*.
- **Systematic learning about the shale:** this could involve taking the opportunity provided by each well to learn more about the reservoir by capturing data (typically by using down-hole measuring instruments) that will enable the character and behaviour of the shale to be better understood. This understanding is an important contributory factor in improving the operational performance (and therefore the environmental impact per unit of production) of each well drilled and in eliminating wells and fracture stages that do not contribute significantly to production. *We estimate the additional cost at $200 000 per well*.

Most of these measures would involve a marginal increase in the overall cost of a large-scale development. But there is potential for reducing costs through better planning of operations, which would also reduce environmental risks:

- **Exploiting economies of scale:** pad drilling and the associated ability to carry out simultaneous operations on more than one well has been shown to bring significant cost savings as well as reducing the total surface footprint. Typically the drilling phase of a number of wells on the pad would be finished first, enabling the completion phase to be carried out for multiple wells in parallel. "Simultaneous operations" of this sort can allow for more efficient use of equipment for hydraulic fracturing. The US company, Continental Resources, has reported a 10% drop in average well cost in the Bakken Shale, from $7.2 million to $6.5 million, by using such an approach at eight well pads. Other industry sources report savings of up to 30%, due to a combination of economies of scale and improvements in operational efficiency. *On this basis, we have estimated savings of 10% per well.*

- **Optimising the number of fracture stages:** this can achieved by acquiring better information about where the sweet spots are likely to be and fracturing only in those zones, rather than simply fracturing every 100 metres, with no science applied. Industry data from different shale plays in the United States show that, on average, between 30% and 40% of fractures do not contribute any production at all. We have assumed conservatively that at least two hydraulic fracturing stages out of twenty could be saved as a result of better reservoir characterisation by systematically learning about the shale. *This would represent a cost saving of around $400 000 per well or equivalent gains in production for the same number of stages.*
- **Learning from experience:** there is a learning curve associated with the drilling and completion of shale-gas wells that, on a large scale of development, can bring significant cost savings as time goes on: these savings are often quoted in conjunction with economies of scale and the optimisation of fracture stages. *For the purposes of our analysis, we have not added any additional saving related to the learning curve.*

Summing up the effects of the more stringent environmental measures applied to the development and the efficiency savings from better planning yields an overall net cost saving of approximately 5%. Most of these savings come from economies of scale and reduced hydraulic fracturing, which more than offset the additional cost of implementing well-specific measures and monitoring environmental effects.

There is potential for even larger cost savings in large-scale developments by optimising the number and location of wells drilled. Given the enormous variability in geology, there are significant variations in the economics of unconventional gas wells, driven largely by differences in the expected cumulative output of each one (referred to as Estimated Ultimate Recovery [EUR]). The ability of operators to locate sweet spots within an unconventional gas play, where output is particularly high, (or their good fortune in doing so) explains a large part of the difference in EUR between wells. The adoption of advanced technologies in drilling and completing wells can also help to increase EUR.

At present, in the vast majority of shale gas developments wells are drilled and hydraulically fractured "geometrically", that is to say at regular intervals, without regard for the changing geology between those intervals. Some wells give very good initial production and others close to zero. A detailed study of more than 7 000 wells in the Barnett Shale in *WEO-2009* showed that half of the horizontal wells drilled were unprofitable, even at the 2009 gas price of $6 per MBtu, while some others were profitable at much lower prices (IEA, 2009). This reflects differences in the amount of gas produced, itself a reflection of the local geology of the formation, but also of differences in the suitability and effectiveness of the well design and hydraulic fracturing operations. Reservoir characterisation and modelling techniques for shales is applied only in a limited manner at present. It is not unreasonable to expect that, had there been smarter selection of drilling targets, the least profitable 20% of wells in our sample would not have been drilled at all. Better understanding of the science of hydrocarbon flows within unconventional gas reservoirs is needed for improved reservoir characterisation and modelling to be achieved (Box 1.7).

Box 1.7 ▷ The potential benefits of better petroleum science

For all the advances that have been made in shale gas production in the United States in recent years, a large number of wells that prove to be very unproductive are still being drilled. Often, the value of the gas and liquids they yield is insufficient to cover the cost, the losses on such wells generally being offset by other wells that prove to be very productive. In addition, recovery factors for shale gas and light tight oil are very low, compared to conventional reservoirs: estimates in most cases do not exceed 15% of the original oil and gas in place. A better scientific understanding of both the geological structure and hydrocarbon flows within shale and tight gas rock should allow producers to target better and to refine their drilling and well-completion operations, driving down the number of unproductive wells and pushing up the estimated ultimate recovery – a tremendous prize for all stakeholders.

Thus far, improvements in unconventional gas technology have largely been concerned with how, on a cost-effective basis, to pump more fluid into more fracture stages in longer horizontal sections in order to increase reservoir contact, and how to better manage the environmental effects. But while advances in drilling and hydraulic fracturing technology have unlocked unconventional reserves that were previously uneconomic, the science of the behaviour of the reservoirs is still not well understood. This makes it very hard to predict decline rates and the ultimate production potential of each play and individual areas and wells. Traditional methods of computer modelling and simulation of oil and gas reservoirs do not work well in the case of shale gas or light tight oil.

This scientific challenge has attracted a significant research effort from industry experts and academia. Breakthroughs in understanding the behaviour of shale and tight-gas reservoirs are expected and are likely to trigger a shift from the current "brute force" approach to production towards a more scientific one, enabling operators to avoid drilling poor wells and using ineffective well-completion methods. This would allow for more efficient use of water and other resources, minimising the environmental footprint and lowering production costs.

The Golden Rules Case and its counterpart

How might unconventional gas re-shape energy markets?

Highlights

- In a Golden Rules Case, we assume that the conditions are in place, including the application of the Golden Rules, to allow for an accelerated global expansion of gas supply from unconventional resources, with far-reaching consequences for global energy markets. Greater availability of gas supply has a strong moderating impact on gas prices and, as a result, demand for gas grows by more than 50% to 2035 and the share of gas in the global energy mix rises to 25% in 2035, overtaking that of coal.
- Production of unconventional gas, primarily shale gas, more than triples in the Golden Rules Case to 1.6 tcm in 2035. The share of unconventional gas in total gas output rises from 14% today to 32% in 2035. Whereas unconventional gas supply is currently concentrated in North America, in the Golden Rules Case it is developed in many other countries around the world, notably in China, Australia, India, Canada, Indonesia and Poland.
- The Golden Rules Case sees a more diverse mix of sources of gas in most markets, suggesting an environment of growing confidence in the adequacy, reliability and affordability of natural gas supplies. An increased volume of gas, particularly LNG, looking for markets in the period after 2020 stimulates the development of more liquid and competitive international markets. The projected levels of output in the Golden Rules Case would require more than one million new unconventional gas wells to be drilled worldwide between now and 2035.
- In a Low Unconventional Case, we assume that – primarily because of a lack of public acceptance – only a small share of unconventional gas resources is accessible for development and, as a result, global unconventional gas production rises only slightly above 2010 levels by 2035. The competitive position of gas in the global fuel mix deteriorates as a result of lower availability and higher prices, and the share of gas in global energy use remains well behind that of coal. The requirement for imported gas is higher and some patterns of trade are reversed, with North America needing significant quantities of imported LNG, and the preeminent position in global supply of the main conventional gas resource-holders is reinforced.
- Although the forces driving the Low Unconventional Case are led by environmental concerns, it is difficult to make the case that a reduction in unconventional gas output brings net environmental gains. The effect of replacing gas with coal in the Low Unconventional Case is to push up energy-related CO_2 emissions, which are 1.3% higher than in the Golden Rules Case. Reaching the international goal to limit the long-term increase in the global mean temperature to two degrees Celsius would, in either case, require strong additional policy action.

Paths for unconventional gas development

There are factors on both the demand and supply sides pointing to a bright future for natural gas, but the key element in the supply outlook is the growth in production of – and expectations for – unconventional gas resources. For the moment, production of unconventional gas is still overwhelmingly a North American phenomenon: in 2010, 76% of global unconventional gas output came from the United States (360 billion cubic metres [bcm]) and a further 13% from Canada (60 bcm). Outside North America, the largest contribution to unconventional gas production came from China and Australia, producing around 10 bcm and 5 bcm of coalbed methane, respectively.[1] But, in light of the North American experience and with evidence of a large and widely dispersed resource base, there has been a surge of interest from countries all around the world in improving their security of supply and gaining economic benefits from exploitation of domestic unconventional resources.

Box 2.1 ▷ Overview of cases

This chapter sets out projections from two cases, for the period to 2035, which explore the potential impact and implications of different trajectories for unconventional gas development.

- A ***Golden Rules Case***, to which the main part of this chapter is devoted, assumes that the conditions are put in place to allow for a continued global expansion of gas supply from unconventional resources. This allows unconventional gas output to expand not only in North America but also in other countries around the world with major resources.
- A ***Low Unconventional Case*** considers the opposite turn of events, where the tide turns against unconventional gas, as environmental and other constraints prove too difficult to overcome.

These projections are assessed against an updated ***baseline***, which takes as its starting point the central scenario (the New Policies Scenario) from the most recent *World Energy Outlook*, *WEO-2011*. The two main cases test a range of favourable and unfavourable assumptions about the future of unconventional gas. A necessary, but not sufficient, condition of the Golden Rules Case is the effective application of the Golden Rules, in order to earn or maintain the "social licence" for the industry to operate. Neither case is advanced as more probable; they are rather designed to inform the debate about the implications of different policy choices for energy markets, energy security and for climate change and the environment.

1. A proportion of gas production in Russia is classified as unconventional, tight gas.

The potential is there for unconventional gas supply to grow rapidly in the coming decades, but the speed at which this supply will grow is still highly uncertain. Outside North America, the unconventional gas business is in its formative years, with major questions still to be answered about the extent and quality of the resource base and the ability of companies to develop it economically. Moreover, as discussed in Chapter 1, social concerns about the impact of producing unconventional gas, particularly the threat of unacceptable environmental damage, have risen as production has grown. Reports of water contamination, earthquakes, and other disruptions to local communities have given unconventional gas production, and the practice of hydraulic fracturing in particular, a bad name in many countries.

It remains to be seen how this social and environmental debate will play out in different parts of the world. In parts of Canada, the United States and Australia, moratoria have been placed on hydraulic fracturing, pending the results of additional studies on the environmental impact of the technology. Even in advance of any commercial production, similar prohibitions are already in force in parts of Europe. There is a distinct possibility that, if these concerns are not directly and convincingly addressed, then the lack of public acceptance in some countries could mean that unconventional production is slow to take off, or, indeed, falters at the global level.

This chapter examines two scenarios, the Golden Rules Case and the Low Unconventional Case (Box 2.1), in the first of which these challenges are overcome and a second in which they are not successfully addressed. The difference in outcomes between them posits a critical link between the way governments and operators respond to these social and environmental challenges and the prospects for unconventional gas production. The strength of this link differs among countries depending on the ways that public concerns and perceptions of risk affect political decision-making. But the assumptions underlying these cases reflect our judgement that the development of this relatively new industry is contingent, in many places, on a degree of societal consent that in some places has yet to be achieved. Moreover, the perception of the industry as a whole is likely to be cast by the performance of its weakest players, not its strongest. Without a general and sustained effort from both governments and operators, the public may not be convinced that the undoubted benefits outweigh potential risks.

Golden Rules and other policy conditions

The Golden Rules, presented and discussed in Chapter 1, are principles designed to minimise the undesirable effects of unconventional gas production on society and the environment. Implementing such principles is in many cases a question of appropriate regulation; but this is not the whole story. The task for policy-makers and regulators is to find the right equilibrium that deals convincingly with social and environmental concerns without removing the economic incentives for developing an important national resource. This balance will vary from country to country, given differing energy security, economic and environmental priorities.

In the Golden Rules Case, we assume that all resource-rich countries formulate their approach to environmental regulation of unconventional gas production in line with these principles and thereby achieve a level of environmental performance and public acceptance that provides the industry with a "social licence to operate". In that sense, the Golden Rules become a necessary (but not sufficient) condition for a wide expansion of unconventional gas supply.

In the Low Unconventional Case, this balance is not found and the Golden Rules are either not adopted or inadequately applied. Whether in response to new incidents of environmental damage or evidence of poor industry performance, the potential social and environmental threats are deemed to be too significant in some countries or regions, to the extent that there are substantial obstacles to developing the resource. Longer-lasting prohibitions are imposed in some countries on technologies that are essential to unconventional gas development, such as hydraulic fracturing, or exclusion zones are created and tight restrictions applied to drilling locations that restrict access to all or part of the resource. Alternatively, either a combination of very strict and detailed regulation imposes prohibitive compliance costs or fears about future regulatory change deter investment.

The application of these Golden Rules is not sufficient in itself to determine successful resource development in countries with unconventional gas potential. Based on experience in the United States, other key factors include:

- **Access to resources:** these considerations include access to geological data on a reasonable and transparent basis, the size of the area covered by a licence and the duration of the licence, and freedom for companies to engage in upstream activities on a competitive basis.
- **The fiscal and regulatory framework:** some countries have high potential in terms of resources but unattractive overall conditions for investment, such as unpredictable fiscal regimes or weak institutions.
- **Availability of expertise and technology:** not least because unconventional gas production requires a large number of wells, the industry needs a skilled and experienced workforce and a well-developed service sector with access to the necessary equipment.
- **Existing infrastructure:** although there are possibilities for small-scale gas gathering arrangements and direct conversion to power (or liquefied natural gas [LNG]), the density of the gas transport infrastructure in areas targeted for unconventional development is an important consideration, as is the existence of guaranteed access to this infrastructure.
- **Markets and pricing:** gas is relatively expensive to transport (compared with its well-head production costs and also with the cost of transporting oil) so companies will be attracted to resources with reliable, proximate markets that offer the necessary

incentives to develop the gas. The absence of market pricing in the host market can eliminate the commercial case for unconventional gas development.

- **Water availability:** water is essential to the production process for shale gas and tight gas (see Chapter 1), and competition with established users in water-stressed areas may constrain unconventional developments.[2]

Experience in the United States points to additional factors such as the number of entrepreneurial and independent companies willing to take the risk of venturing into a new industrial sector, which is coupled with their ability to mitigate market risk via well-developed financial markets. In the absence of widespread examples outside the United States, it is impossible for the moment to say which of the ingredients listed above are essential for large-scale unconventional gas development, which of them are merely desirable, and which might play only a limited role. What can be said, though, is that the mix of conditions and constraints varies by country: in some, environmental and social issues will be decisive; in others, the quality of the resource, the nature of the upstream supply chain, market conditions and prices, or the overall legal system and investment security, may be more significant.

Our general assumption in the Golden Rules Case is that all of the potential obstacles listed are either overcome or do not prove a serious constraint on unconventional gas development. A major motivation for supportive policies is assumed to be the desire of countries to secure the economic benefits of a valuable indigenous resource and, in many cases, also to improve energy security by reducing dependence on imported gas. The essence of the Golden Rules is that they bolster public confidence in the determination of public authorities and operators alike to overcome the social and environmental hazards, thereby creating a political environment that allows for the enactment of other policies encouraging investment in this sector. In the Low Unconventional Case, weak or absent political support deters the implementation of supportive measures for unconventional gas development, such as attractive fiscal and investment terms.

In the projections for the different cases, which are presented later in this chapter, the results of adopting the Golden Rules, in the Golden Rules Case, and the results of failing to do so, in the Low Unconventional Case, are compared against the outcome in a baseline case. This baseline case uses the central scenario of the *WEO-2011* (the New Policies Scenario) as its starting point, but incorporates more recent data, where these have become available, and certain new assumptions, such as the rate of GDP growth, which are described more fully later in the chapter. The baseline case sees natural gas prices converge towards the levels assumed in the *WEO-2011* New Policies Scenario, whereby prices in the United States reach $8.2 per million British thermal units (MBtu) in 2035 (in year-2010 dollars) and average import prices into Europe and Japan reach $12.2/MBtu and $14.2/MBtu respectively. However, the baseline case excludes the application in full of the

2. The *WEO-2012* will include a dedicated chapter on the links between energy and water use.

Golden Rules and the other supportive policies that generate faster growth in natural gas production in the Golden Rules Case.

Unconventional gas resources

Our projections depend, first, on the size of the available resource. Drawing on data from a variety of sources, we estimate that remaining technically recoverable resources of shale gas amount to 208 trillion cubic metres (tcm), tight gas 76 tcm and coalbed methane 47 tcm (Table 2.1). Russia and countries in the Middle East are the largest holders of conventional gas resources (and Russia has by a distance the largest overall gas resources). However, a large part of the world's remaining recoverable unconventional gas lies in countries or regions that are currently net gas importers and face increasing import dependency, such as China, and the United States, which before the recent boom in unconventional gas in North America was looking at the prospect of rising LNG imports (Figure 2.1). Different assumptions about the terms of access to the unconventional resource base in China and in the United States, and in other unconventional resource-rich countries around the world, are a main determinant of the variations between levels of production in the Golden Rules Case and the Low Unconventional Case.

Table 2.1 ▷ Remaining technically recoverable natural gas resources by type and region, end-2011 (tcm)

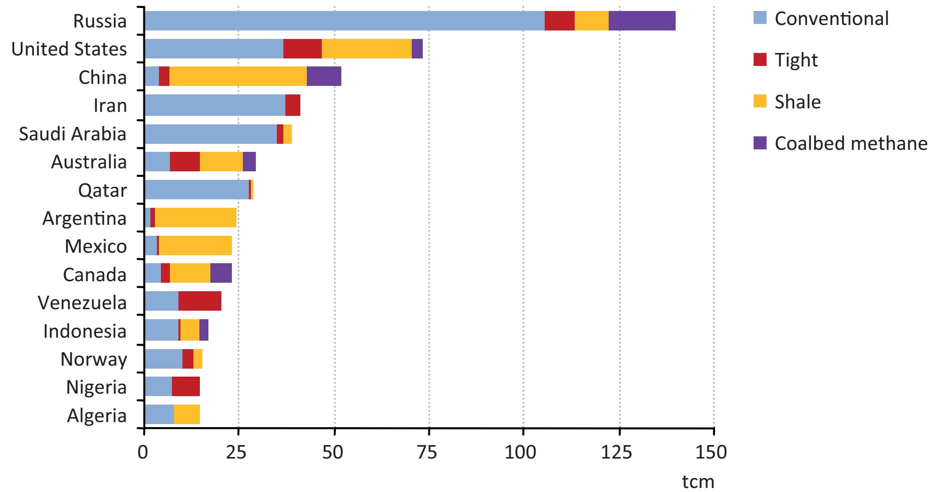
	Total		Unconventional		
	Conventional	Unconventional	Tight Gas	Shale Gas	Coalbed methane
E. Europe/Eurasia	131	43	10	12	20
Middle East	125	12	8	4	-
Asia/Pacific	35	93	20	57	16
OECD Americas	45	77	12	56	9
Africa	37	37	7	30	0
Latin America	23	48	15	33	-
OECD Europe	24	21	3	16	2
World	**421**	**331**	**76**	**208**	**47**

Source: IEA analysis.

Note: The resource estimate for coalbed methane in Eastern Europe and Eurasia replaces a figure given in the *WEO-2011* and in the *Golden Age of Gas* publications (IEA, 2011a and 2011b), which included a "gas-in-place" estimate for Russia instead of the estimate for technically recoverable resources.

Although they are undoubtedly large, unconventional gas resources are still relatively poorly known, both in terms of the extent of the resource in place and judgements about how much might be economically extracted. The industry is still in the learning phase when it comes to many resources outside North America: each unconventional resource play brings with it distinctive challenges and it has not yet been demonstrated that technologies well adapted to existing production areas can unlock the resource potential in all areas.

Figure 2.1 ▷ Remaining recoverable gas resources in the top fifteen countries, end-2011



Source: IEA analysis.

In particular for shale gas, our analysis and projections in this report rely on estimates from the pioneering work of Rogner (Rogner, 1997) and the landmark study from Advanced Resources International (ARI), published by the US Energy Information Administration (EIA) in 2011 (US DOE/EIA, 2011a); these are distinctive in applying consistent standards of evaluation to a large number of countries. On the one hand, resources could easily be even larger than indicated in these studies, as they do not examine all possible shale gas reservoirs around the world. On the other hand, several publications have provided estimates significantly lower than the ARI study: the United States Geological Survey (USGS), whose resource assessments are generally among the most authoritative, has recently published several regional studies indicating lower resources. This is the case, for example, for the Krishna-Godavari shale gas basin in India (USGS, 2012) for which they report a mean estimate of 116 bcm (4.1 trillion cubic feet [tcf]), compared with the ARI estimate of 765 bcm (27 tcf); this much more conservative estimate can be traced back to a smaller estimate for the productive area of the shale and to a smaller mean recovery per well (assuming the same drainage area).[3] Studies by the Polish Geological Institute with support from USGS also give a much lower estimate (a range of 346 bcm to 768 bcm versus the 5.3 tcm given in the ARI study[4]) for shale gas resources in Poland (PGI, 2012). China has

3. The methodologies used for the two studies are different. ARI first estimates gas-in-place and then applies a recovery factor. USGS estimates directly the recoverable resources based on recovery per well and well drainage areas derived by analogy with reservoirs in the United States for which data is available. The methodology used to determine well drainage areas has not been published yet by USGS, making it difficult to compare with industry-accepted values.

4. The different resource estimates can have a substantial impact on the outcome of our projections: see the references to Poland in Chapter 3.

also released new estimates of shale gas resources that are about 20% lower than those given by ARI (MLR, 2012). The much talked-about USGS study of the Marcellus shale in the northeast United States estimated the undiscovered shale resources there at 2.4 tcm (84 tcf), much lower than the 11.6 tcm (410 tcf) recoverable resources reported by the US EIA in 2011 (USGS, 2011).[5] US EIA subsequently reduced their estimate for recoverable gas in the Marcellus to 4 tcm (141 tcf) (US DOE/EIA, 2012).

Estimates of coalbed methane resources are drawn from the German Federal Institute for Geosciences and Natural Resources (BGR, 2011) and US EIA. Tight gas resources are generally poorly defined and known: the exceptions are the United States, Canada and Australia, for which national resource data are used. Tight gas resource estimates for other countries are derived from Rogner.

In the Golden Rules Case, the entire resource base for unconventional gas is assumed to be accessible for development, including in countries and regions where moratoria or other restrictions are currently in place. In the Low Unconventional Case, however, the constraints imposed by the absence of supportive policies (in particular the Golden Rules themselves) and the uncertainties over the size and quality of the resource base were modelled by assuming that only a small part of the ultimately recoverable unconventional resource base is accessible for development. The key assumptions by country or region for the Low Unconventional Case are:

- **United States**: only 65% of tight gas, 45% of coalbed methane and 40% of shale gas resources are accessible. For shale gas, this could, as an example, correspond to excluding all new developments in the northeast United States[6], in California and in the Rocky Mountains, while the more traditional oil and gas producing regions, such as Texas, Oklahoma or the Gulf Coast, would continue to develop their shale resources. Alternatively, restrictions could apply to some parts of the prospective acreage in all regions, such as the more densely populated parts, or those with serious competition in uses for water. For coalbed methane, this could essentially restrict developments to regions that are already producing. Tight gas has been produced for many years in numerous traditional hydrocarbon-producing regions, so tight gas production is not assumed to be restricted as much as the other categories.

5. Strictly speaking, the USGS and US EIA numbers cannot be compared as USGS reports undiscovered gas resources while US EIA reports total recoverable resources, which differ from undiscovered by proven reserves and discovered-but-undeveloped resources. However, neither organisation has provided a breakdown of these three categories. Overall, unconventional gas challenges the usual definitions, as there is no real discovery process (the locations of most gas bearing shales in the world are already known); it is more an appraisal process: the process of establishing that a given shale, and/or what part of the shale, can produce economically. As a result the difference between undiscovered and discovered-but-not-developed is blurred and it is important to clarify the assumption used in various resources estimates.

6. The *World Energy Model* (*WEM*) currently uses the US EIA 2011 resources numbers (US DOE/EIA, 2011b), before their downward revision for the Marcellus shale, pending publication of more details for the background of this revision. So the northeast United States, and the Marcellus shale in particular, represents about half of the estimated resources. Note that *WEM* treats the United States as a single region, so there is no projection of production by basin.

- **China**: only 40% of the coalbed methane and 20% of the shale gas resources are assumed to be accessible. Public acceptance is likely to be a lesser influence in China than in other countries (although we are looking forward 25 years and, if the changes that have occurred in the last 25 years in China are any guide, public sensitivity to environmental issues could become significantly greater during the projection period), but other factors could restrict the ambitious official plans for unconventional gas production (Box 2.4).
- **India**: only 30% of the coalbed methane and 20% of the shale gas resources are assumed to be accessible. The large projected gas import requirements of India make it unlikely that public opposition would force a complete ban. On the other hand, on current estimates, unconventional gas resources in India are not sufficient to make more than a dent in these imports and our assumption is consistent with a political decision to restrict development of all but the less contentious resource areas.
- **Australia**: only 40% of coalbed methane and none of the shale gas resources are assumed to be accessible. Development of both types of resources has already become controversial in Australia. About 5 bcm of coalbed methane was produced in Australia in 2010 and there are three large-scale projects underway to build LNG plants fed by coalbed methane. The restriction to 40% of available resources essentially amounts to no new projects being authorised beyond those announced.
- **Rest of the world**: no new unconventional gas resources are assumed to be developed outside Canada (for which we use percentages about half of those in the United States, to reflect similar dynamics, but the smaller part of the resources so far developed) and Russia (where, in any event, unconventional resources are not expected to play a significant role).[7]

Development and production costs

The costs of developing and producing unconventional gas are made up of several elements: capital costs, operational costs, transportation costs, and taxes and royalties. Capital costs, often called finding and development costs, are usually dominated by the costs of constructing wells. As discussed in Chapter 1 (under "Implications for Industry"), shale gas wells do cost more than conventional gas wells in the same conditions, because of the additional costs of multistage hydraulic fracturing; the same consideration applies to tight gas wells, for the same reason. Coalbed methane wells have so far been relatively cheap, compared with conventional gas wells, because production has been at shallow depths in regions with well-developed markets. Operational costs, also called lifting costs, are those variable costs that are directly linked to the production activity: they may differ according to local conditions (but not necessarily between conventional and

7. This assumption about the rest of the world (with the partial exception of Canada and Russia) has the virtue of simplicity, although it is a little extreme in some countries that are already producing coalbed methane without any controversy; however, the amounts involved are too small to have any impact on prices or energy security.

unconventional gas produced under similar conditions). The cost of bringing gas to market is distance-dependent and is identical for conventional and unconventional gas.

The final element, taxes and royalties, varies greatly between jurisdictions; in addition to a profit tax component, it very often includes fixed or production-related taxes (paid to governments) and/or royalties (paid to the resource owner, which may or may not be governments). Countries or regions that have higher capital and operating costs, due to their geography or market conditions, often create a more attractive fiscal regime in order to attract investment. This can go as far as offering subsidies: China provides subsidies for coalbed methane and shale gas production.

On the basis of these costs, one can estimate a "break-even cost", or "supply cost", the market value required to provide an adequate real return on capital for a new project (normally taken to be 10% for a project categorised as risk-free and rising with incremental risk). This break-even cost does not apply to legacy production from largely depreciated installations. Lifting costs, transport costs, and taxes and royalties are usually directly expressed in US dollars per unit of gas produced. The significance of capital costs is very dependent on the amount of gas recovered per well. This also varies greatly: the best shale gas wells in the United States are reported to have Estimated Ultimate Recovery (EUR) of 150 to 300 million cubic metres (mcm) (5 to 10 billion cubic feet [bcf]); but many shale gas wells have EUR that is 10 or 100 times less. The average EUR varies from one shale to another, but also depends on the experience of the industry in a given shale: with time, the industry optimises the technologies used and extracts more gas from each well. Outside the United States, there is essentially no experience so far, but drilling longer horizontal wells should help improve EUR per well (in many jurisdictions in the United States, horizontal well length is limited by acreage unit size regulations).

It follows from the discussion of costs that the break-even costs for gas can vary greatly from one location to the next, or within a single country (Table 2.2). For example in the United States, break-even costs for dry gas wells probably range from $5/MBtu to $7/MBtu; gas containing liquids has a lower (gas) break-even cost, which can be as low as $3/MBtu, as the liquids add considerable value for a small increase in costs (associated gas from wells producing predominantly oil can have an even lower break-even cost). Since conventional gas resources are already fairly depleted onshore and most future conventional gas production will therefore come from more expensive offshore locations, the range of break-even costs for conventional and unconventional gas in the United States is fairly similar.

In Europe, the costs of production are expected to be about 50% higher, with a range of break-even costs between $5/MBtu and $10/MBtu. Conventional and unconventional gas are expected to be in the same range, as conventional resources are depleted and new projects are moving to the more expensive Norwegian Arctic. China has a cost structure similar to that of the United States, but shale reservoirs there tend to be deeper and more geologically complex; similarly, coalbed methane reservoirs in China tend to be in remote locations, so we estimate the break-even cost range to be intermediate between that of the United States and that of Europe – from $4/MBtu to $8/MBtu (although there are production subsidies in place that can bring this figure down). This estimate for China applies to both conventional and unconventional gas, as the easy conventional gas is depleting and production is moving to offshore or more remote regions. In countries that have large, relatively easy, remaining conventional gas, such as the Middle East, with break-even costs of less than $2/MBtu, the break-even cost range for unconventional gas is expected to be higher (similar to that for unconventional gas in the United States).

Table 2.2 ▷ Indicative natural gas well-head development and production costs in selected regions (in year-2010 dollars per MBtu)

	Conventional	Shale gas	Coalbed methane
United States	3 - 7	3 - 7	3 - 7
Europe	5 - 9	5 - 10	5 - 9
China	4 - 8	4 - 8	3 - 8
Russia	0 - 2, 3 - 7*	-	3 - 5
Qatar	0 - 2	-	-

* The lower range for Russia represents production from the traditional producing regions of Western Siberia and the Volga-Urals; the higher range is for projects in new onshore regions such as Eastern Siberia, offshore and Arctic developments.

In the Golden Rules Case, the development and production cost assumptions are not increased because of the application of the Golden Rules; as discussed in Chapter 1, the application of the Golden Rules does have some cost impact, but not sufficient to push up the costs of production significantly (and, possibly, not at all). The same starting point is used for development and production costs in the Low Unconventional Case; costs in this case, though, are subject to the general assumption (built into the modelling) that production tends to become more costly as a given resource starts to become scarcer. Since access to unconventional gas resources is limited in this case, the rate of increase in the costs of production is higher than in the Golden Rules Case.

Natural gas prices

The price assumptions in the Golden Rules Case and in the Low Unconventional Case vary substantially, reflecting the different regional and global balances between supply and demand in each case (Table 2.3). The price assumptions in the Golden Rules Case reflect the favourable outlook for unconventional gas supply that results from successfully addressing the potential barriers to its development. Greater availability of gas supply has a strong moderating impact on gas prices. Conversely, lower production of unconventional gas in the Low Unconventional Case means that higher natural gas prices are required to bring the different regional markets into balance.

Table 2.3 ▷ Natural gas price assumptions by case (in year-2010 dollars per MBtu)

		Golden Rules Case		Low Unconventional Case	
	2010	2020	2035	2020	2035
United States	4.4	5.4	7.1	6.7	10.0
Europe	7.5	10.5	10.8	11.6	13.1
Japan	11.0	12.4	12.6	14.3	15.2

Note: Natural gas prices are expressed on a gross calorific value basis. Prices are for wholesale supplies exclusive of tax. The prices for Europe and Japan are weighted average import prices. The United States price reflects the wholesale price prevailing on the domestic market

North America is the region where the unconventional gas industry has grown most rapidly and, unsurprisingly, is also the region where the impact on markets and prices has thus far been greatest. Historically low prices are being obtained for natural gas, relative to other energy forms such as oil. More surprisingly, given the relative isolation of North American markets from other major gas-using regions, this development has already had profound international impacts. These have arisen because North America has become almost self-sufficient in gas, whereas many LNG investments in the decade 2000 to 2010 were made in the expectation that the North American region would be a substantial net LNG importer. Import infrastructure in excess of 100 bcm was built in the United States alone in this period, with matching LNG supply investments in major producers, such as Qatar. However, in 2011, net LNG imports to North America were less than 20 bcm, out of a total market exceeding 850 bcm: 8 bcm into the United States and 9 bcm into Mexico and Canada. Hence, major quantities of LNG supply became available for other global markets, including Asia and Europe.

Natural gas prices in the United States are assumed to rise from today's historic lows in both cases, but they increase much more quickly in the Low Unconventional Case. The contrasting future roles of North America in global gas trade in the two cases help to explain these different price trajectories. In the Golden Rules Case, the region becomes a significant net LNG exporter, on the back of continued increases in unconventional gas output in the United States and Canada and an expansion in LNG export capacity. Natural gas prices in the United States are assumed to reach a plateau of between \$5.5/MBtu and \$6.5/MBtu during the 2020s (the levels which we assume are sufficient to support substantial volumes of dry gas production) before rising to \$7.1/MBtu in 2035. Exports at the levels anticipated in this case are relatively small, compared with the overall size of the United States' gas market, and do not play a decisive role in domestic price-setting (although they are significant for other markets). By contrast, in the Low Unconventional Case, North America remains a net importer of gas, with imports growing rapidly after 2025. With the region needing to draw its incremental gas supply from international markets, the natural gas price in the United States is pushed up much more quickly than in the Golden Rules Case, reaching \$10/MBtu in 2035.

The weighted average import price assumptions for Europe and for Japan are likewise lower in the Golden Rules Case than in the Low Unconventional Case. Within this basic trend, differences between the two markets reflect the different balances between gas supply and demand in each case, as well as the various pricing mechanisms present and how these mechanisms are assumed to evolve. At present, gas prices are set freely in several markets, including North America, the United Kingdom and, to a somewhat lesser extent, Australia, an approach known as gas-to-gas competition. However, much of the gas traded across borders in the Asia-Pacific region is sold under long-term contracts, with linkages to the price of oil or refined products. Prices in continental Europe are predominantly oil-linked, though in recent years a mixture of the two systems (and many variations in between) has emerged, with oil-indexed prices co-existing – often uneasily – with prices set by gas-to-gas competition. We assume that pressure to move away from prices set by oil-indexation and towards those established through gas-to-gas competition is significantly greater in the Golden Rules Case than in the Low Unconventional Case.

In the Golden Rules Case, the United States is expected to play an important role in the evolution of international natural gas pricing mechanisms. Initial contracts for United States LNG exports have been written on the basis of the price at the main domestic natural gas trading hub (Henry Hub), plus liquefaction and transport costs, plus profit, rather than the traditional oil-price indexation prevailing in many of the markets where this gas will be sold. In the Golden Rules Case, this is assumed to put pressure on oil-indexed price formulas for natural gas, moderating gas price increases and provoking a greater degree of convergence in international prices towards those set by gas-to-gas competition. We do not, though, assume that this process of creating a single, liquid or competitive international gas market is completed in the Golden Rules Case (a situation in which natural gas price differentials between regions would reflect only the costs of transportation between them). An important moderating factor in importing regions, especially in Asia, is that most existing natural gas import contracts will continue to remain in force for many years and are based on oil indexation, so average prices cannot be expected to fall dramatically. In addition, some major new export projects (including, for example, from Canadian plants) are greenfield LNG operations, likely to push for traditional pricing arrangements. Hence, while the rise of North American LNG exports in the Golden Rules Case is a major development in global gas markets, we anticipate that wholesale prices in the United States remain at least $5 to $6 below Japanese import prices, with European import prices between these two.

Other assumptions

Both cases include updated assumptions on GDP, compared with the *WEO-2011*, with average annual GDP growth of 3.5% for the period 2012 to 2035, compared with 3.4% in *WEO-2011* for the same period (this allows the global economy in 2035 to reach the same overall size as assumed in *WEO-2011*). World population is assumed to expand from an estimated 7.0 billion in 2012 to 8.6 billion in 2035, as in *WEO-2011*. The projections for natural gas incorporate new demand and supply data by country and region for 2011, where these are available. Prices for oil, coal and carbon-dioxide (CO_2) are likewise updated to include new data for 2011, but they still converge towards the levels assumed in the central scenario of the *WEO-2011,* the New Policies Scenario. This means that the average IEA crude oil import price – a proxy for international oil prices – reaches $120/barrel in 2035 in year-2010 dollars (a nominal oil price of $212/barrel). The IEA steam coal import price increases to $112/tonne in 2035.

In the Golden Rules Case, to complement the impact on gas demand arising from lower prices that improve the competitive position of gas compared with other fuels, we also assume intervention by governments to foster demand growth in countries experiencing a large rise in indigenous gas production. In the United States, for example, supportive policies are assumed to facilitate increased use of natural gas in the road-transport sector, in particular for the commercial fleet. These additional demand-side policies are not included in the baseline case nor in the Low Unconventional Case, because the motivation for their adoption, *i.e.* higher indigenous production and lower prices, is absent.

Another notable change in policy assumptions, compared with the *WEO-2011*, occurs in Japan, where, pending the outcome of the ongoing review of Japan's Strategic Energy Plan, the future contribution of the nuclear sector to power generation is revised downwards in all cases.

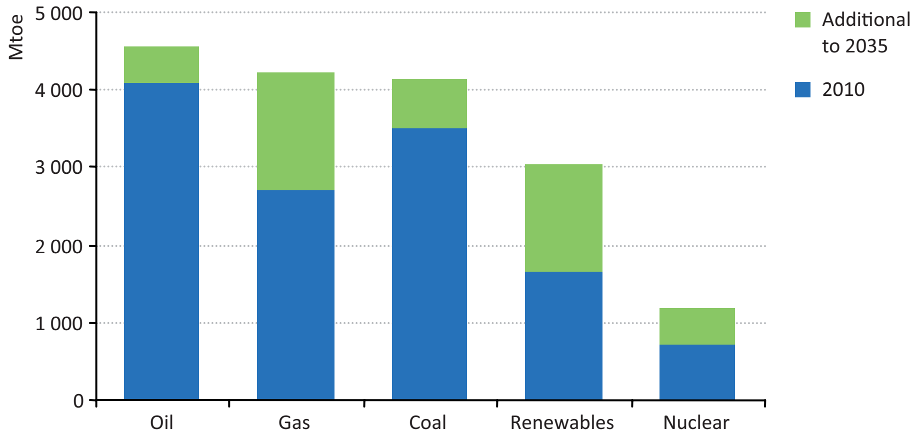
Otherwise, all assumptions remain constant from the New Policies Scenario of the *WEO-2011* (which takes into account policies and declared future intentions as of mid-2011), including the assumption that new measures are introduced to implement announced policy commitments, but only in a relatively cautious manner. These commitments include national pledges to reduce greenhouse-gas emissions and, in certain countries, plans to phase out fossil-fuel subsidies.

The Golden Rules Case

Demand

Global primary energy demand in the Golden Rules Case rises from around 12 700 million tonnes of oil equivalent (Mtoe) in 2010 to 17 150 Mtoe in 2035, an increase of 35%. Natural gas demand increases in the period to 2020 by more than 700 bcm (compared with 2010 levels), the equivalent of adding another United States to the global demand balance, and by a further 1.1 tcm in the period from 2020 to 2035, reaching a total of 5.1 tcm (4 230 Mtoe) in 2035. This is around 300 bcm, or 6%, higher than in the baseline case in 2035, with average annual growth over the projection period of 1.8%, compared with 1.5%. In the Golden Rules Case, gas accounts for about one-third of the overall increase in primary energy demand, a larger contribution than that made by any other fuel and equivalent to the growth in demand for coal, oil and nuclear combined (Figure 2.2). By 2035, natural gas has overtaken coal to become the second most important fuel in the energy mix.

Figure 2.2 ▷ World primary energy demand by fuel in the Golden Rules Case



Different rates of gas demand growth, albeit less pronounced than in the exceptional year of 2011[8], are expected to characterise gas markets in the longer term (Table 2.4). In the Golden Rules Case, 80% of the growth in gas demand comes from outside the OECD; China, India and the countries of the Middle East require an additional 900 bcm of gas in 2035, compared with consumption in 2010. In China and India and other emerging economies, natural gas at present often has a relatively low share of total energy consumption and its use is being specifically promoted as a way to diversify the fuel mix and reap some environmental benefits, often displacing coal as the preferred fuel to supply fast-growing urban areas. While growth in gas demand is healthy even in many of the more mature OECD gas markets – a development that is encouraged by the lower prices for natural gas in the Golden Rules Case – the growth in China alone is more than the anticipated growth in all of the OECD countries put together. Gas demand in China grows over the period 2010 to 2035 by 480 bcm, reaching a total of around 590 bcm in 2035 (larger than current gas demand in the European Union), meaning that developments on both the supply and demand sides in China will continue to have a substantial impact not just in the Asia-Pacific region but – via the wider effects on trade and prices – in markets around the world.

Gas used for generating power and heat is the single largest component of gas demand, accounting for around 40% of total gas consumed. Alongside the lower perceived risk of building gas-fired plants and the lower environmental impact, compared with other fossil fuels, the natural gas prices assumed in the Golden Rules Case improve the competitive

8. Preliminary data suggest that gas consumption in Europe declined by around 11% compared with the previous year, pulled down by warm weather, a sluggish European economy and a weak competitive position in the power sector compared with coal. This was in marked contrast to developments in the Asia-Pacific region: Korea and Japan showed a dramatic upsurge in demand for LNG, the latter linked to reduced output of nuclear energy following Fukushima, and Chinese gas demand continued its meteoric rise, becoming a larger gas consumer than any OECD country except the United States. The United States also saw growth in consumption, of around 2.5%, spurred by low prices that neared $2/MBtu in late 2011.

position of natural gas and push up gas demand for power generation to more than 2 tcm by 2035. The role of gas in power generation increases from 22% to 24%, with coal and oil (the latter a marginal fuel in power generation) ceding share in response. Gas use in buildings and in industry also increases substantially, reaching 1 060 bcm and 970 bcm respectively by the end of the projection period.

Table 2.4 ▷ Natural gas demand by region in the Golden Rules Case (bcm)

	2010	2020	2035	2010-2035*
OECD	**1 601**	**1 756**	**1 982**	**0.9%**
Americas	841	921	1 051	0.9%
United States	*680*	*717*	*787*	*0.6%*
Europe	579	626	692	0.7%
Asia Oceania	180	209	239	1.1%
Japan	*104*	*130*	*137*	*1.1%*
Non-OECD	**1 670**	**2 225**	**3 130**	**2.5%**
E. Europe/Eurasia	662	736	872	1.1%
Russia	*448*	*486*	*560*	*0.9%*
Asia	398	705	1 199	4.5%
China	*110*	*323*	*593*	*7.0%*
India	*63*	*100*	*201*	*4.7%*
Middle East	365	453	641	2.3%
Africa	101	130	166	2.0%
Latin America	144	200	252	2.3%
World	**3 271**	**3 982**	**5 112**	**1.8%**
European Union	*547*	*592*	*644*	*0.7%*

* Compound average annual growth rate

Although volumes are small compared with the other end-use sectors, the Golden Rules Case sees strong growth in gas use in the transport sector. This is encouraged both by lower prices, compared with oil, and also by government policies, for example support for developing the necessary refuelling infrastructure. Use of natural gas for road transportation increases by more than six times in the period to 2035, reaching close to 150 bcm in 2035. For the moment, transport is the only major end-use sector where gas is not widely used: although there are viable natural gas vehicle technologies, there are only a few countries where these are deployed at scale. More than 70% of all natural gas vehicles and half of all fuelling stations are found in just five countries: Pakistan, Iran, Argentina, Brazil and India. In our projections, India and the United States lead the growth in natural gas consumption for transport, primarily in commercial fleets, buses and municipal vehicles that can use central depots for refuelling.

Implications for other fuels

The implications of applying the Golden Rules to unconventional natural gas extend beyond gas to other competing fuels. As the share of gas rises from 21% of global primary energy consumption in 2010 to 25% by 2035 (compared with 23% in the baseline case), growth in demand for oil and coal is constrained and, marginally, also demand for nuclear and renewable energy (Table 2.5).

Table 2.5 ▷ World primary energy demand by fuel in the Golden Rules Case

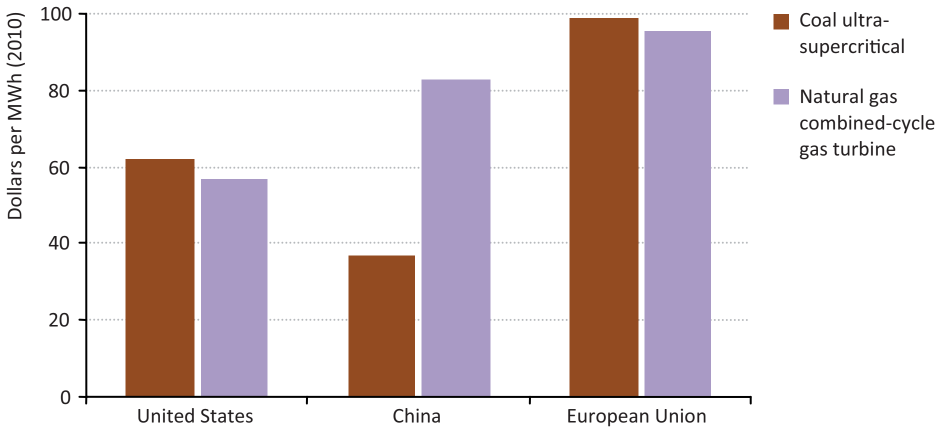
	Demand (Mtoe)			Share		
	2010	2020	2035	2010	2020	2035
Coal	3 519	4 109	4 141	28%	28%	24%
Oil	4 094	4 381	4 548	32%	29%	27%
Gas	2 700	3 291	4 228	21%	22%	25%
Nuclear	719	927	1 181	6%	6%	7%
Hydro	295	376	472	2%	3%	3%
Biomass	1 262	1 496	1 896	10%	10%	11%
Other renewables	110	287	676	1%	2%	4%

Oil continues to be the dominant fuel in the primary energy mix, with demand increasing from about 4 100 Mtoe in 2010 to 4 550 Mtoe in 2035, but its share in the primary energy mix drops from 32% in 2010 to 27% in 2035. Compared with the baseline case, lower gas prices promote substitution for oil in the transport and power sectors, resulting in global oil demand being reduced by some 2 million barrels per day (mb/d) in 2035.

Primary coal consumption in the Golden Rules Case rises until around 2025 and then levels off. Its share in the energy mix declines from 28% in 2010 to 24% in 2035. In that year, coal demand is around 3% lower (115 Mtoe) than in the baseline case, an amount greater than total current European imports of hard coal. Three-quarters of coal demand growth stems from the power sector. Lower gas prices favour gas over coal for new builds in most countries (Figure 2.3). However, in some countries, such as China, coal remains cheaper than gas, in the absence of prices that internalise environmental externalities, such as local pollution or CO_2 emissions. In this situation, Chinese government policies aimed at increasing gas use are crucial to its development. Globally, excluding China, 3.5 units of gas-fired electricity generation are added for each new unit of coal-fired electricity generation.

Over the *Outlook* period, nuclear output grows, but it is marginally below our baseline case in 2035. Gas prices have a direct influence on new nuclear construction in liberalised markets, mostly in OECD countries, where we expect nuclear output to grow 12% less than our baseline. However, most of the global growth in nuclear will occur in non-OECD countries, where specific national plans to expand nuclear capacity are less likely to be affected by changing market conditions.

Figure 2.3 ▷ **Electricity generating costs for new coal- and natural gas-fired power plants in selected regions in the Golden Rules Case, 2020**



The global outlook for renewable sources of energy is not affected substantially by the increased use of gas in the Golden Rules Case, with volumes and shares of output remaining very close to those in the baseline case. Due to lower gas (and consequently electricity) prices, the growth of electricity output from non-hydro renewables is reduced globally by 5% compared with our baseline. This global average figure hides some larger differences in specific countries, where the impact is stronger, due to the price levels and to the type of support policies in place. This is, for example, the case in the United States, where the growth of electricity from non-hydro renewables is some 10% lower with respect to the baseline.

There are factors working both against, and in favour of, renewables in a world of more abundant gas supplies. Depending on the type of policies in place, an abundance of natural gas might diminish the resolve of governments to support low and zero-carbon sources of energy: lower gas prices (and therefore lower electricity prices) can postpone the moment at which renewable sources of energy become competitive without subsidies and, all else being equal, therefore make renewables more costly in terms of the required levels of support. However, an expansion of gas in the global energy mix can also facilitate greater use of renewable energy, if policies are in place to support its deployment, given that gas-fired power generation can provide effective back-up to variable output from certain renewable sources. Moreover, lower electricity prices can encourage customer acceptance of a higher component of electricity from renewable sources. Ultimately, the way that renewables retain their appeal, in a gas-abundant world, will depend on the resolve of governments. We assume that existing policies and support mechanisms remain in place as part of the efforts by governments to address the threat of a changing climate.

Supply

In the Golden Rules Case, total gas production grows by around 55%, from 3.3 tcm in 2010 to 5.1 tcm in 2035. Over the same period, unconventional gas production increases from around 470 bcm in 2010 to more than 1.6 tcm in 2035. Although unconventional gas output grows relatively slowly in the early part of the projection period, reflecting the time required for new producing countries to develop commercial production, for the projection period as a whole, unconventional gas represents nearly two-thirds of incremental gas supply (Table 2.6).

Table 2.6 ▹ Natural gas production by region in the Golden Rules Case (bcm)

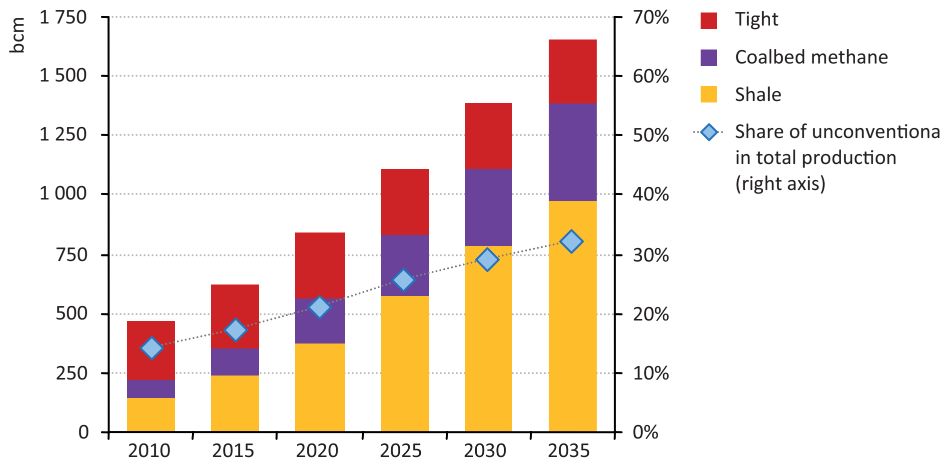
	2010		2020		2035		2010-2035**
	Total	*Share of unconv** *	Total	*Share of unconv** *	Total	*Share of unconv** *	
OECD	**1 183**	**36%**	**1 347**	**49%**	**1 546**	**60%**	**1.1%**
Americas	821	51%	954	62%	1 089	68%	1.1%
Canada	*160*	*39%*	*174*	*57%*	*177*	*67%*	*0.4%*
Mexico	*50*	*3%*	*52*	*12%*	*87*	*43%*	*2.2%*
United States	*609*	*59%*	*726*	*67%*	*821*	*71%*	*1.2%*
Europe	304	0%	272	4%	285	27%	-0.3%
Poland	*6*	*11%*	*9*	*37%*	*34*	*90%*	*7.1%*
Asia Oceania	58	9%	121	49%	172	64%	4.5%
Australia	*49*	*11%*	*115*	*51%*	*170*	*65%*	*5.1%*
Non-OECD	**2 094**	**2%**	**2 635**	**7%**	**3 567**	**20%**	**2.2%**
E. Europe/Eurasia	826	3%	922	3%	1 123	6%	1.2%
Russia	*637*	*3%*	*718*	*4%*	*784*	*6%*	*0.8%*
Asia	431	3%	643	20%	984	56%	3.4%
China	*97*	*12%*	*246*	*45%*	*473*	*83%*	*6.6%*
India	*51*	*2%*	*75*	*21%*	*111*	*80%*	*3.2%*
Indonesia	*88*	*-*	*106*	*2%*	*153*	*37%*	*2.2%*
Middle East	474	0%	581	1%	776	2%	2.0%
Africa	202	1%	264	1%	397	5%	2.7%
Algeria	*79*	*-*	*101*	*1%*	*135*	*8%*	*2.2%*
Latin America	159	2%	226	4%	286	22%	2.4%
Argentina	*42*	*9%*	*53*	*9%*	*72*	*48%*	*2.1%*
World	**3 276**	**14%**	**3 982**	**21%**	**5 112**	**32%**	**1.8%**
European Union	*201*	*1%*	*160*	*7%*	*165*	*47%*	*-0.8%*

* Share of unconventional production in total natural gas production.

** Compound average annual growth rate.

The share of unconventional gas in total gas production increases in the Golden Rules Case from 14% in 2010 to 32% in 2035 (Figure 2.4). Of the different sources of unconventional supply, tight gas, at 245 bcm, accounted for just over half of global unconventional production in 2010. However, it is rapidly overtaken in our projections by production of shale gas, which rises from around 145 bcm in 2010 (31% of total unconventional output) to 975 bcm in 2035 (almost 60% of the total). Production of coalbed methane likewise grows rapidly, from 80 bcm in 2010 to nearly 410 bcm in 2035.

Figure 2.4 ▷ **Unconventional natural gas production by type in the Golden Rules Case**



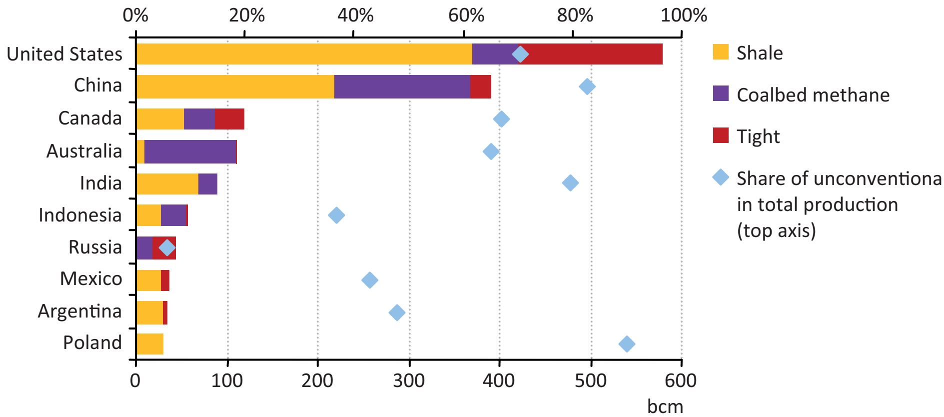
The continued expansion of unconventional gas production in North America means that the United States moves ahead of Russia as the largest global gas producer, with about 820 bcm of total gas production in 2035, compared with 785 bcm in Russia. North American unconventional output, with substantial contributions also from Canada and Mexico, rises to nearly 740 bcm in 2035 in the Golden Rules Case. But increased unconventional production also occurs widely around the world: whereas unconventional gas production in 2010 is dominated by North America, the share of North America in global unconventional production falls to around 70% in 2020 and only 45% in 2035.[9]

China becomes a major gas producer in the Golden Rules Case and the second-largest global producer of unconventional gas, after the United States (Figure 2.5). Progress with developing unconventional gas resources is bolstered by the twin policy commitments of increasing the share of natural gas in the Chinese energy mix and developing, where possible, the domestic resource base so as to mitigate increased reliance upon energy imports. The large resource base for shale gas and coalbed methane allows very rapid growth in unconventional production from around 2017 onwards and total unconventional

9. More detailed discussion of the regulatory issues and production outlooks for North America, China, Europe and Australia are included in Chapter 3 of this report.

production reaches just over 110 bcm in 2020 and 390 bcm in 2035, 83% of total Chinese gas production.

Figure 2.5 ▷ Ten largest unconventional gas producers in the Golden Rules Case, 2035



Similar policy objectives are assumed to drive an expansion in unconventional gas production elsewhere in Asia, notably in India where unconventional gas supply rises to nearly 90 bcm in 2035 (80% of total gas output). The currently known unconventional gas resource base in India can meet only a part of India's incremental needs, given the prospect of strong growth in gas demand, and production growth starts to tail off towards the end of the projection period. In Indonesia, by contrast, resources of both conventional and unconventional gas are very large; some recent conventional discoveries are offshore and relatively expensive to develop, so the onshore unconventional plays, including rich potential for coalbed methane, are attractive by comparison. Unconventional gas production in Indonesia rises to around 55 bcm in 2035 (almost 40% of total output). Australia is another country that has the opportunity to develop both conventional and unconventional resources with a mix of coalbed methane, tight and shale gas. In the Golden Rules Case, unconventional gas makes up about 65% of Australia's 170 bcm of total gas output by 2035.

The expansion of unconventional gas production in China and the United States (and, to a lesser extent, also in Europe) creates strategic challenges for existing gas exporters. This is evident in the projections for Russia, which remains by far the largest producer of conventional gas.[10] Developments in the Golden Rules Case call into question the speed at which Russia will need to develop relatively expensive new fields in the Yamal peninsula, in the Arctic offshore and in Eastern Siberia. In our projections, Russia's total gas production rises to about 785 bcm in 2035, more than 20% above 2010, but below the levels foreseen in

10. A part of Russia's production is classified as tight gas although this is very similar to conventional production in practice; hydraulic fracturing to enhance flow rates is rarely used in gas wells. Russia is, though, projected to expand its output of coalbed methane by 2035.

Russian policy or company outlooks and in our baseline. In the Middle East, an increasingly important challenge for gas producers – with the exception of an export-oriented producer like Qatar – is to meet increasing demand for gas on domestic markets. In our Golden Rules Case projections, this imperative to meet domestic needs leads to small amounts of shale gas being produced, mainly in Saudi Arabia and Oman, but conventional gas continues to predominate. In North Africa, though, unconventional gas plays a slightly more significant role, with Algeria, Tunisia and Morocco starting to produce shale gas in the early 2020s. By the end of the projection period, unconventional gas production reaches around 8% of total output in Algeria; with conventional resources becoming scarcer by this time, unconventional gas helps to maintain consistently high levels of production and export. Overall gas production in Africa is bolstered by expanded conventional output from a traditional producer, Nigeria, but also by output from new conventional producers, such as Mozambique and Angola.

Latin America has large potential for unconventional gas development, with Argentina (primarily shale gas) having the largest resource base, followed by Venezuela (tight gas) and then Brazil (shale gas). Attention in Argentina is focused on the Neuquén Basin in Patagonia, which helps Argentinean unconventional production reach 35 bcm by 2035 in the Golden Rules Case, almost half of the total gas output. Both Venezuela and Brazil have ample conventional resources, which means that there is less need to develop their unconventional potential during the projection period; however, some unconventional gas is produced by 2035 in Bolivia (5 bcm), Peru (5 bcm), Paraguay (3 bcm) and Uruguay (3 bcm).

Implications for other fuels

In the Golden Rules Case, the conditions supportive of unconventional gas production also support increased output of natural gas liquids (NGLs), extracted from liquids-rich shale gas, as well as light tight oil.[11] This oil is analogous in many ways to shale gas, both in terms of its origins – it is oil that has not migrated, or at least not migrated far, from the (shale) source rock – and in terms of the production techniques required to exploit it. Light tight oil is being produced from many of the same basins as unconventional gas in the United States, and, in a price environment combining high oil prices and very low prices for natural gas, there is a strong economic incentive to target plays with higher liquids content. In the Golden Rules Case, we project a strong increase in production of light tight oil in the United States, with the potential for production to spread also to other countries rich in this resource (Box 2.2).

11. Almost all shale gas plays produce some liquids and light tight oil production likewise comes with some associated gas. The distinction between liquids-rich unconventional gas plays and gas-rich light tight oil reservoirs is not clear-cut; it normally depends on the relative energy content of the gas versus the liquids produced, but this can vary over time for a single well.

Box 2.2 ▷ The liquid side of the story – light tight oil

The spectacular rise in oil production from North Dakota and Texas in the United States clearly illustrates the growth potential for light tight oil. The Bakken formation under North Dakota has been known about since the 1950s, but production from this formation remained under 100 thousand barrels per day (kb/d) until only a few years ago, since when it has surged to over 500 kb/d and looks set to continue growing. The Eagle Ford shale in south Texas, adjacent to the Mexican border, also shows considerable promise, with production expected to grow from almost nothing three years ago to around 400 kb/d by the end of 2012. Combined production from the Bakken, the Eagle Ford and other emerging light tight oil plays in the United States is expected to reach 2 mb/d by 2020 in the Golden Rules Case.

United States' NGL production from shales such as the Barnett, Eagle Ford and Marcellus is also increasing rapidly and up to 1 mb/d of new capacity is expected to be added by 2020. The growth in NGL production is creating new opportunities for the petrochemical industry, but action will be required to remove pipeline bottlenecks and provide additional fractionation and storage facilities if the benefits are to be fully realised. The growth in global production of NGLs from shale formations and light tight oil in the period to 2020, predominantly in North America, makes up almost half the incremental growth in oil supply over this period.

Production outside North America of NGLs from shale and of light tight oil is unlikely to make a large contribution to global liquids production before 2020 as much evaluation work still needs to be done. However, the Neuquén basin in Argentina shows promise, YPF announcing potential resources of 7 billion barrels (YPF, 2012), while the extension of the Eagle Ford shale into Mexico is also a focus of attention. Our projections for light tight oil production outside North America remain small even beyond 2020, as we have yet to see sufficient progress in confirming resources, so there is some upside potential. It should be noted, however that on the basis of current knowledge, light tight oil resources are expected to be of less consequence than shale gas resources: whereas the estimated shale gas resources in the United States represent at least 35 years of 2010 domestic gas demand, the known light tight oil resources make up no more than four years of domestic oil demand. This is why we currently project light tight oil production in the United States to peak in the 2020s.

The liquids content of shale gas plays is an important consideration in their economic viability as NGLs are easily transported to world markets, while market opportunities for gas are often only local, at prices that may not be aligned to international prices for reasons of policy or infrastructure. However there is always a degree of uncertainty about the extent of liquids content until new shales have been drilled and tested.

International gas trade, markets and security

In the Golden Rules Case, the developments having the most impact on gas markets and security are the increasing levels of unconventional production in China and in the United States, the former because of the way that it slows the growth in Chinese import needs and the latter because it allows for gas exports from North America. The implication of these two developments in tandem is to increase the volume of gas, particularly LNG, looking for markets in the period after 2020.

China's requirement for imported natural gas in the Golden Rules Case grows from around 15 bcm in 2010 to 80 bcm in 2020 and then to 120 bcm in 2035. These volumes are about half the corresponding imports in the baseline case. Chinese gas imports at the levels projected in the Golden Rules Case could be covered by existing contractual arrangements for LNG and pipeline supplies (from Central Asia and Myanmar) until well into the 2020s, pushing back the need for additional projects aimed at the Chinese market.

With the United States developing as an LNG exporter over the period to 2020 and Canada also starting to export LNG from its west coast, exports from North America reach 35 bcm by 2020, after which they stabilise just above these levels as the opportunities for export start to narrow. The influence of these exports on trade flows and pricing is larger than these volumes suggest. LNG from the United States, if priced at the prices prevailing on the domestic gas trading hub, can compete with oil-indexed gas in both the European and Asia-Pacific markets in the Golden Rules Case, and the mere presence of this source of LNG (more so than the actual level of export) plays an important role in creating a more competitive international market for gas supply.

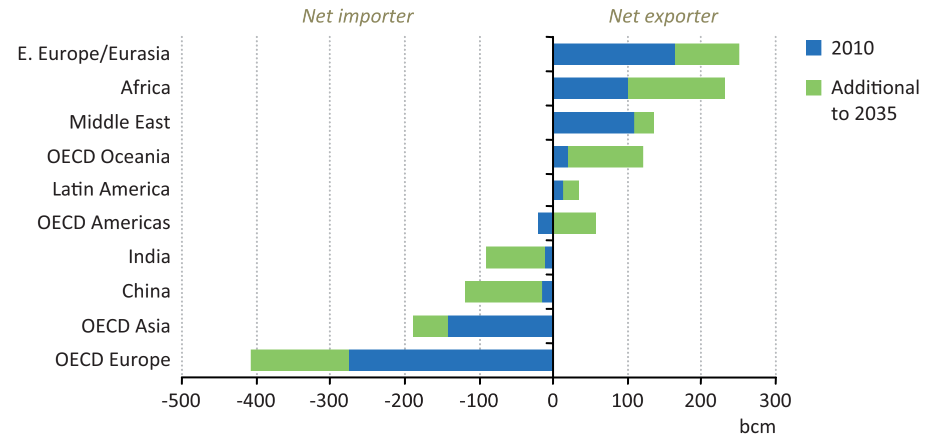
The total volume of gas traded between *WEO* regions[12] in the Golden Rules Case in 2035 is 1 015 bcm. This represents an increase of nearly 50%, compared with the volume of inter-regional trade in 2010 (Figure 2.6), but it is some 15% below the figure for 2035 in our baseline case. The share of inter-regional trade in global supply rises to 22% in 2015, but international market conditions start to ease over the period to 2020 and beyond, as new sources of unconventional gas start to be developed closer to the main areas of consumption. This pick-up in unconventional gas production means that the share of inter-regional trade in global supply plateaus after 2015 before falling to 20% by 2035, reversing the expectation that international trade will play an increasingly important role in meeting global needs.

The European Union's growing requirement for imported gas accounts for 40% of the increase in global inter-regional gas trade in the Golden Rules Case. Here too, the development of indigenous unconventional gas moderates somewhat the growth in imports, so that they reach 480 bcm in 2035, about 135 bcm more than in 2010. Among importing countries in Asia, Japan and Korea (which do not have potential to develop

12. Trade between the 25 regions included in the *WEM*. It does not include trade between countries within a single region.

indigenous production) see imports rise steadily, as does India, whose import requirement rises to nearly 90 bcm from around 10 bcm in 2010.

Figure 2.6 ▷ Natural gas net trade by major region in the Golden Rules Case



Box 2.3 ▷ Implications for prices and pricing mechanisms

In an environment where gas is potentially available from a greater variety of sources, buyers not only in Europe but also in Asia could well insist on greater independence from oil prices in the pricing of gas supplies, particularly when gas is used in the fast-growing power sector in which oil is disappearing as an energy source. The Golden Rules Case is likely to see accelerated movement towards hub-based pricing or a hybrid pricing system in which alternatives to oil-price indexation plays a much larger role in both Europe and across Asia.

The way such a change might play out in practice would depend to a large degree on the reaction of the main traditional exporters, who could confront greater risks in financing expensive upstream developments and transportation projects. Producers such as Russia and Qatar, the largest current exporters of natural gas, have access to ample conventional reserves, with costs that are in most cases substantially lower than those of unconventional gas (and other conventional producers as well). With well-developed export infrastructure, these countries could undercut the prices offered by most other exporters on international markets, retaining or expanding export volumes by offering gas to markets on more attractive terms than others. Alternatively, they could aim to maintain higher prices for their exports, but at the risk of losing market share. In the Golden Rules Case, their strategic choice would have substantial implications for the location of investment and production, including the speed of development of unconventional resources. The net result for gas consumers, however, would be broadly the same: lower prices for imported natural gas.

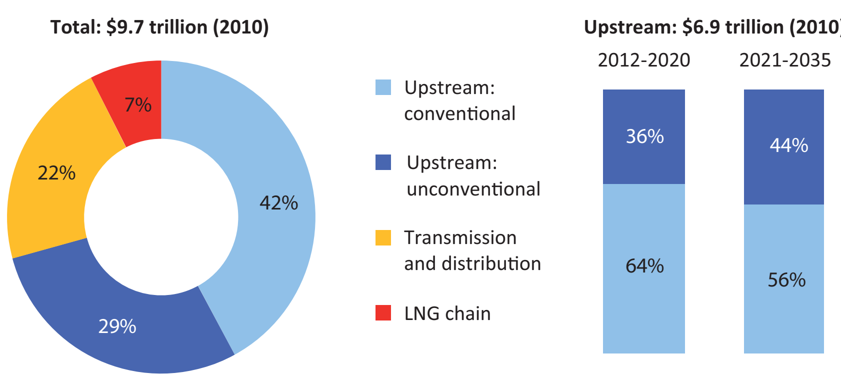
Russia and the Middle East supplied around 45% of inter-regional gas trade in 2010; this declines to 35% in 2035 in the Golden Rules Case, as other players announce or expand their presence in the market, notably Australia, the United States and producers in Africa and Latin America. From around 20 bcm in 2010, Australia's exports rise quickly to 120 bcm in 2035, based on a rapid expansion of LNG capacity, which permits new markets to be captured in the earlier part of the projection period, during which demand for imports remains relatively strong. By around 2020, African exports – based on new conventional projects and LNG, thanks to the large recent discoveries offshore east and west Africa – overtake those from the Middle East.

Overall, the Golden Rules Case presents an improved picture of security of gas supplies. High dependence on imports, in itself, is not necessarily an indicator of insecure supply; but the conditions observed in the Golden Rules Case of a more diverse mix of sources of gas in most markets, including both indigenous output and imports from a range of potential suppliers, suggests an environment of growing confidence in the adequacy, reliability and affordability of natural gas supplies.

Investment and other economic impacts

At the global level, for conventional and unconventional gas together, the Golden Rules Case requires $9.7 trillion in cumulative investment in gas-supply infrastructure in the period 2012 to 2035 (in year-2010 dollars). This represents an increase of $390 billion, compared with the baseline case, reflecting the need to bring on more production to meet higher demand and a slight increase in unit production costs as unconventional resources make up a growing share of production. Spending on gas exploration and development, to find new fields and bring them into production and to maintain output from existing ones, amounts to nearly $6.9 trillion, bolstered by the large number of new wells required (see Spotlight).

Figure 2.7 ▷ Cumulative investment in natural gas-supply infrastructure by type in the Golden Rules Case, 2012-2035 (in year-2010 dollars)



SPOTLIGHT

How many wells? How many rigs?

Expanded unconventional gas production requires a significant increase in the number of unconventional gas wells over the coming decades, though there is a huge range of uncertainty when calculating the extent of the requirement for unconventional gas wells for a projected level of production. Key variables are the average ultimate recovery per well and the average decline rate of production in the early years, both of which vary significantly between shale gas, tight gas and coalbed methane wells.[13]

We estimate that, to meet the global unconventional gas production requirements of the Golden Rules Case, more than one million unconventional gas wells would need to be drilled globally between 2012 and 2035. For comparison, around 700 000 oil and gas wells have been drilled in the United States over the last 25 years and half a million are currently producing gas. At present, global drilling activity for both conventional and unconventional resources is heavily concentrated in the United States, where more than half of the world's drilling rig fleet (around 2 000 active oil and gas drilling rigs, including those used for unconventional gas) is deployed to sustain production of just 9% of the world's oil and 19% of the world's gas.

In the Golden Rules Case, the United States would still account for around 500 000 of the new unconventional gas wells required by 2035, with the yearly drilling requirement rising from around 7 000 wells per year to 25 000 per year by 2035 (and the unconventional gas rig count increasing by the same order of magnitude, given that the efficiency of rig use probably has potential for only modest increases).

China would have a cumulative requirement of some 300 000 unconventional gas wells over the projection period and an annual requirement increasing from around 2 000 in the early years to 20 000 wells nearer 2035. Assuming that drilling becomes more efficient with time, this might correspond to an increase in the number of unconventional gas drilling rigs from around 400 to 2 000, a demanding increase in the rig count. There are an estimated 1 000 rigs in China at present, but only a fraction of these are capable of horizontal drilling.

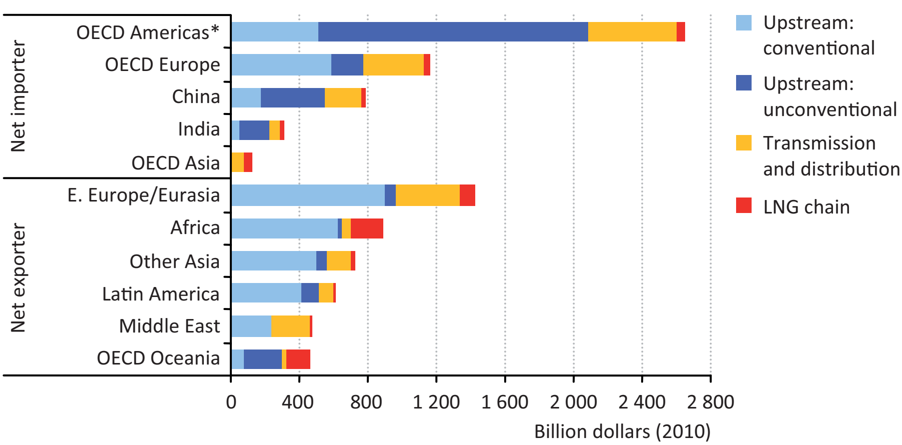
In the European Union, the cumulative number of wells in the projection period is around 50 000, increasing to around 3 000 per year by the 2030s. The number of drilling rigs required is between 500 and 600; there are currently around 50 land rigs in Europe, of which only around half may be capable of horizontal drilling.

13. For the purpose of these calculations, we have used an average EUR of around 1 bcf, assumed that about 50% of EUR is recovered in the first three years of production, and a 15% average decline rate of current unconventional gas production (in the United States). Varying these assumptions within a reasonable range produces very different outcomes in terms of the number of wells.

Unconventional resources attract an increasing share of this upstream investment – about 36% before 2020 and 44% in the subsequent period to 2035 – as prospective areas mature (Figure 2.7). Being geographically well-dispersed and closer to demand centres, unconventional gas diminishes the need for long-distance gas transport infrastructure to some degree. Nevertheless, growing trade in the Golden Rules Case requires additional LNG facilities and new long-haul pipelines. Cumulative investment in the LNG chain is $0.7 trillion and investment in gas transmission and distribution infrastructure, including smaller scale networks to connect end-users, absorbs $2.1 trillion.

The proportion of upstream investment made in countries that hold unconventional resources increases. Spending on exploration and development for unconventional gas in the United States alone is more than double total upstream spending in any other country or region.[14] China also becomes one of the world's leading locations for upstream gas investment, thanks to its huge resource base. Countries that were net importers of gas in 2010 make some of the most significant investments in unconventional gas, accounting for more than three-quarters of total unconventional upstream investment (Figure 2.8). This investment can generate the wider economic benefits associated with improved energy trade balances, lower energy prices and employment, all of which add economic value for unconventional resource holders.

Figure 2.8 ▷ Cumulative investment in natural gas-supply infrastructure by major region and type in the Golden Rules Case, 2012-2035



* OECD Americas become a net exporter of natural gas by 2020 in the Golden Rules Case.

The outlook for energy trade balances improves for unconventional resource holders in the Golden Rules Case. China and the European Union remain large net importers of gas,

14. Because of the rapid decline in production in shale gas wells, maintaining production requires continuous investment in drilling new wells. This explains why the United States needs the lion's share of the investment in unconventional gas: although it does not grow supply as much as China for example, it needs investment just to sustain its already substantial level of unconventional gas production.

but indigenous unconventional gas production tempers their import bills, which stabilise at about 0.2% and 0.7% of GDP, respectively, after 2020. Australia, where production far outstrips domestic gas demand, sees export revenues reach nearly 2% of GDP in 2035. Net exports of gas bring revenues to the United States after it ceases to be a net gas importer; the more substantial impact on energy trade balances in the United States results from light tight oil production and increased NGLs from higher unconventional gas production, which contribute to a considerable reduction in its oil import bill – to 0.8% of GDP in 2035, compared with a peak of 2.8% of GDP in 2008.

Climate change and the environment

Energy-related CO_2 emissions in the Golden Rules Case reach 36.8 gigatonnes (Gt) in 2035, an increase of over 20% compared with 2010 (Table 2.7) but lower than the 2035 baseline projection by 0.5%. At the global level, there are two major effects of the Golden Rules Case on CO_2 emissions, which counteract one another. Lower natural gas prices mean that, in some instances, gas displaces the use of more carbon-intensive fuels, oil and coal, pushing down emissions. At the same time, lower natural gas prices lead to slightly higher overall consumption of energy and, in some instances, to displacement of lower-carbon fuels, such as renewable energy sources and nuclear power. Overall, the projections in the Golden Rules Case involve only a small net shift in anticipated levels of greenhouse-gas emissions.

Table 2.7 ▷ World energy-related CO_2 emissions in the Golden Rules Case (million tonnes)

	2010	2020	2035	2010-2035*
OECD	12 363	12 157	10 716	-0.6%
of which from natural gas	3 034	3 336	3 758	0.9%
Non-OECD	16 960	21 327	24 674	1.5%
of which from natural gas	3 082	4 118	5 781	2.5%
World	**30 336**	**34 648**	**36 795**	**0.8%**

* Compound average annual growth rate.

The Golden Rules Case puts CO_2 emissions on a long-term trajectory consistent with stabilising the atmospheric concentration of greenhouse-gas emissions at around 650 parts per million, a trajectory consistent with a probable temperature rise of more than 3.5 degrees Celsius (°C) in the long term, well above the widely accepted 2°C target. This finding reinforces a central conclusion from the *WEO* special report on a Golden Age of Gas (IEA, 2011b), that, while a greater role for natural gas in the global energy mix does bring environmental benefits where it substitutes for other fossil fuels, natural gas cannot on its own provide the answer to the challenge of climate change. This conclusion could be changed by widespread application of technologies such as carbon capture and storage, which could reduce considerably the emissions from the consumption of gas (and other fossil fuels); but this is not assumed in the period to 2035.[15]

At country level, the impact of the Golden Rules Case on greenhouse-gas emissions from gas depends to a large degree on the structure of domestic fuel use, in particular for power generation. In countries where the average greenhouse-gas intensity of power generation is already close to that of natural gas, as for example in Europe, the addition of extra natural gas to the fuel mix has relatively little impact on the overall emissions trajectory. By contrast, in countries heavily reliant upon coal for electricity generation, such as China, the increased availability of natural gas has a more substantial impact on CO_2 emissions. Such increased use of gas also reduces emissions of other pollutants; compared with burning coal, combustion of natural gas results in lower emissions of sulphur dioxide (SO_2), nitrogen oxides (NO_X) and gas also emits almost no particulate matter. Local emissions of particulate matter and NO_X are the main causes of low air quality – a particularly important consideration for emerging economies seeking to provide energy for fast-growing urban areas.

Unconventional gas production itself inevitably results in some changes to the land, to surface water and to groundwater systems, particularly given the scale of the production envisaged in the Golden Rules Case. As indicated in the Spotlight, we estimate that production at these levels would require the drilling of over one million new wells in the course of the projection period, over half of which would be in the United States and China. These operations have to be managed strictly in accordance with the Golden Rules, or the associated social and environmental damage will cut short attainment of the Golden Rules Case.

The Low Unconventional Case

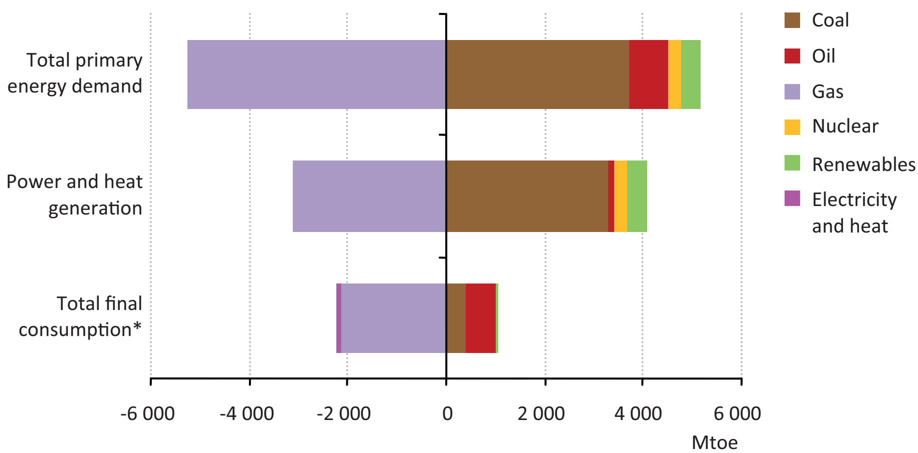
Demand

In the Low Unconventional Case, where the Golden Rules are not applied and environmental and other constraints on unconventional gas development provide too difficult to overcome, the competitive position of gas in the global fuel mix deteriorates, compared with the Golden Rules Case, as a result of lower availability and higher prices. Global demand for gas grows more slowly, reaching 4.6 tcm in 2035. The difference in primary gas demand in 2035 between the Low Unconventional Case and the Golden Rules Case is about 535 bcm, an amount close to total gas demand in the European Union in 2010. In the global energy mix, whereas in the Golden Rules Case gas overtakes coal by 2035, in the Low Unconventional Case the share of gas in the global energy mix increases only slightly, from 21% in 2010 to 22% in 2035, remaining well behind that of coal (whose share decreases from 28% to 26%) and of oil.

15. There is the possibility that the capacities for CO_2 storage might be affected by hydraulic fracturing. A recent study (Elliot and Celia, 2012) estimated that 80% of the potential area to store CO_2 underground in the United States could be prejudiced by shale and tight gas development, although others have argued that, even if the rock seal in one place were to be broken by hydraulic fracturing, other layers of impermeable rock underneath the fractured area would block migration of the CO_2.

The fall in gas demand in the Low Unconventional Case, relative to the Golden Rules Case, is mostly compensated for by increased consumption of coal (Figure 2.9). The cumulative difference in total primary gas demand over the projection period is around 5 200 Mtoe (6.3 tcm); coal accounts for almost three-quarters of the increase in the demand for other fuels, the largest coming in China (accounting for about 40% of the additional coal demand). The total primary energy used for power and heat generation is higher in the Low Unconventional Case because of the substitution of gas-fired generation by coal-fired generation; being less efficient, coal plants require more energy to produce the same amount of electricity. In power generation, around 75% of the fall in gas-fired power is taken up by coal. In total final consumption, the effect is felt primarily through the increase in demand for oil, because gas fails to make the same inroads in the transportation sector.

Figure 2.9 ▷ Cumulative change in energy demand by fuel and sector in the Low Unconventional Case relative to Golden Rules Case, 2010-2035



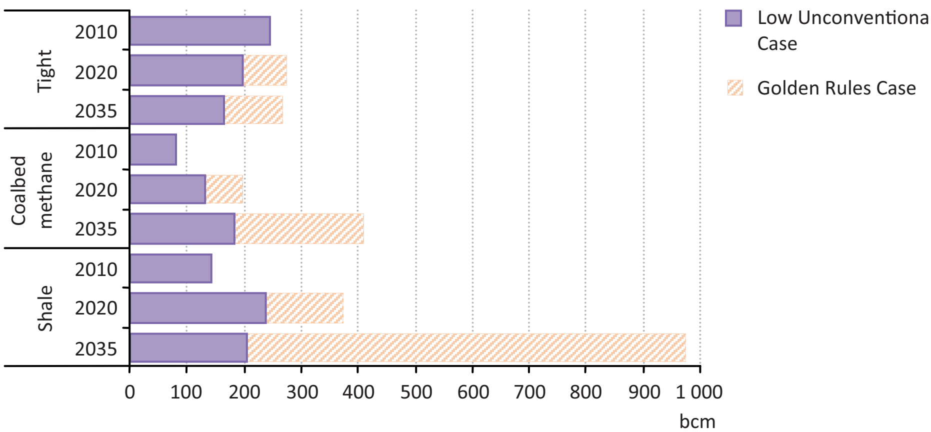
* Total final consumption is the sum of consumption by the end-use sectors industry, transport, buildings (including residential and services) and other (including agriculture and non-energy use).

Supply

In the Low Unconventional Case, total gas supply is lower, at 4.6 tcm, and unconventional production is much lower than in the Golden Rules Case. Unconventional gas production in aggregate rises above 2010 levels of 470 bcm but reaches only 570 bcm in 2020 and falls back to 550 bcm by 2035. Unconventional gas contributes only 6% to global gas production growth over the projection period, meaning that the share of unconventional gas in total gas output falls slightly over time, from 14% in 2010 to 12% in 2035. This is a long way below the 32% share reached by unconventional gas in 2035 in the Golden Rules Case. The difference in unconventional gas production in 2035 between the cases is over 1 tcm, equivalent to 5% of total primary energy supply.

In the Low Unconventional Case, the largest impact is on production of shale gas (Figure 2.10). At a global level, shale gas production increases by 40% over the projection period, reaching just above 200 bcm in 2035, about one-fifth of the level reached in the Golden Rules Case. Tight gas production falls to 165 bcm. Output of coalbed methane is slightly more resilient, rising by two-and-a-half times to around 185 bcm, 45% of the level reached in the Golden Rules Case. This is accounted for by the fact that coalbed methane resources are typically in areas that have existing coal mining operations, in which there is often less resistance to coalbed methane operations than to other types of unconventional gas development – and that the case can be made on environmental grounds that producing the gas is preferable to mining the coal.[16]

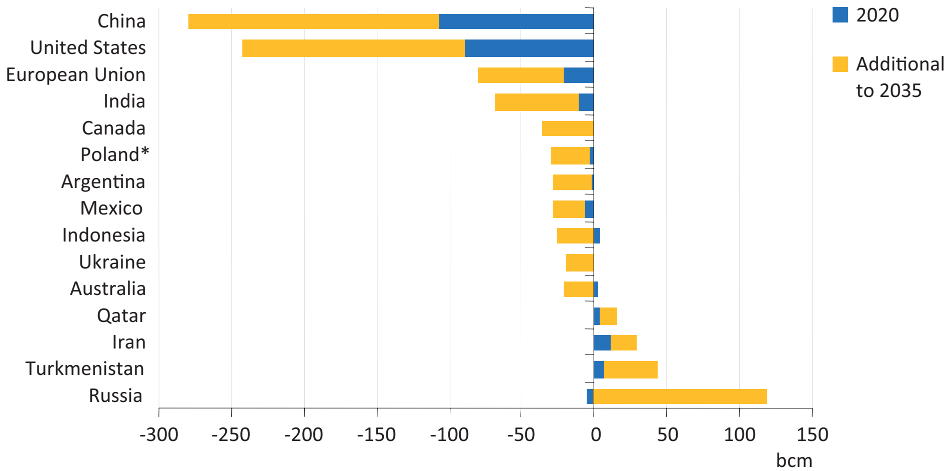
Figure 2.10 ▻ Unconventional gas production by type and case



The reduction in unconventional gas output in the Low Unconventional Case has most impact on China and the United States; their total gas production is lower in 2035 by 280 bcm and 240 bcm, respectively. This represents a 30% reduction in US output, but a much larger fall, 60%, in Chinese production relative to the Golden Rules Case (Figure 2.11 and Box 2.4). There are also major declines in output in the European Union (particularly Poland), India, Canada, Argentina, Mexico, and Indonesia. By contrast, the Low Unconventional Case shores up the preeminent position of the main conventional gas resource-holders. Even though total gas supply is lower than in the Golden Rules Case, Russia (around +115 bcm), Iran (nearly +30 bcm) and Qatar (just over +15 bcm) all post significant increases in their 2035 production, compared to the Golden Rules Case. In the Low Unconventional Case, increased demand from Europe and China for Russian gas means that Russia accounts for 20% of global supply, compared with 15% in the Golden Rules Case.

16. Coalbed methane production can actually reduce methane emissions if the gas would have been released by subsequent coal mining activities (this is sometimes referred to as coal mine methane production).

Figure 2.11 ▷ **Change in natural gas production by selected region in the Low Unconventional Case relative to the Golden Rules Case**



* The change in Polish output is included also in the figures for the European Union.

Box 2.4 ▷ **What could lead to a Low Unconventional Case in China?**

The Chinese government has announced ambitious targets for future production of coalbed methane and shale gas: 6.5 bcm of shale gas and 30 bcm of coalbed methane in 2015, and 60 to 100 bcm of shale gas in 2020. These targets are supported by large producer subsidies for both types of resources. Our projections for the Golden Rules Case show a somewhat slower rate of increase before 2020, but are generally in line with official targets. Public opposition to unconventional gas developments is not currently manifest in China; if it were to develop over the projection period without gaining a commensurate regulatory and industry response, including application of the Golden Rules, the result could be production restrictions leading to an output plateau near the level of the 2020 targets, instead of the continuing growth projected in the Golden Rules Case. There are other hurdles which could also hold back the development of unconventional gas in China:

- The resource base could turn out to be much smaller than currently estimated. The current resource estimates are largely extrapolations from a small number of wells.
- Recovery factors or production rates could be lower than thought. In the United States, different gas shale deposits and different coalbed methane deposits yield very different levels of production. Not enough is known yet about the Chinese reservoirs to confirm that the range of productivity will be similar to that observed

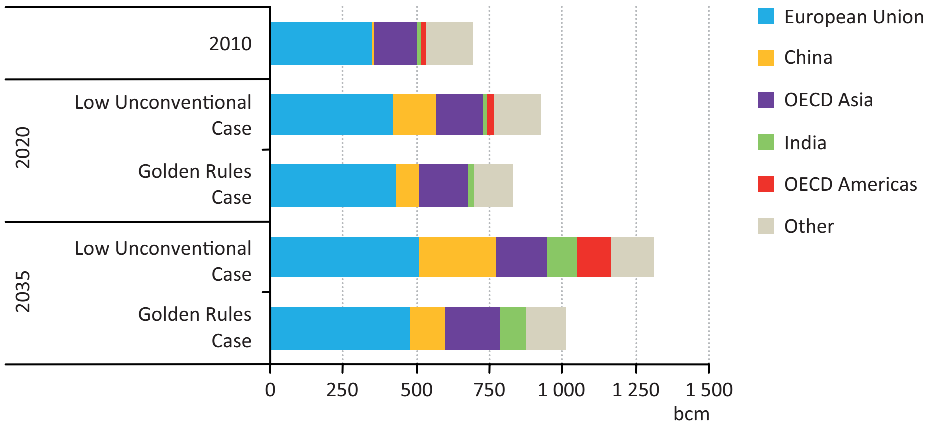
in the United States. On the assumption of similar productivity, the Golden Rules Case will require drilling something like 300 000 new unconventional gas wells in China during the projection period, already a very demanding level of activity. Even modest reductions in productivity would test the limits of the drilling capacity of the country.

- The economics could turn out to be disappointing. Many of the shale gas reservoirs in China are known to be deeper and more complex that those currently exploited in the United States. Both of these factors have a strong influence on the economics. The costs of well construction scale up rapidly with depth. Moreover, most of the coalbed methane resources are located far from large consumption centres: transportation costs make such resources not much more attractive than imports.
- Water availability: a significant part of the shale gas resources is located in regions where either water availability is limited or where competition with agricultural users of the water resources is likely to be a serious issue. This could limit the number of wells and hydraulic fracturing treatments that can be performed in those regions.
- Wavering government support: shale gas and coalbed methane production currently benefit from large subsidies in order to promote their development. When the volumes get large, such subsidies may not be sustainable. Or subsidies to fossil fuels in general may become unacceptable in the later part of the projection period. Loss of subsidies and worsening economics could curb the growth of unconventional gas production from the mid-2020s.

International gas trade, markets and security

The picture of inter-regional trade in the Low Unconventional Case is radically different from that described in the Golden Rules Case. The volume of trade is almost 300 bcm higher in the Low Unconventional Case in 2035, up about 30%, and some patterns of trade are also reversed, with North America requiring large quantities of imported gas to meet its net requirements (Figure 2.12). The United States, a strategically significant gas exporter in the Golden Rules Case, imports nearly 100 bcm by the end of the projection period in the Low Unconventional Case. Despite lower overall gas demand, China's demand for pipeline and LNG imports in 2035 reaches 260 bcm in the Low Unconventional Case, nearly 145 bcm higher than in the Golden Rules Case.

Figure 2.12 ▷ Major natural gas net importers by case



Among the exporters, the share of Russia and the Middle East in global inter-regional trade increases slightly to 46% in 2035 in the Low Unconventional Case, compared with a drop to 35% in the Golden Rules Case. Against a backdrop of rising import dependence in some key gas-consuming regions and a more limited number of potential suppliers, the outlook for customers for gas in the Low Unconventional Case looks less bright. Competition among importers becomes more intense, contributing to tighter markets in Europe and Asia. In North America, with the marginal supply coming from international markets, relatively expensive LNG imports pull up domestic prices in the United States – the opposite effect from the Golden Rules Case, where competitively priced exports have a mitigating effect on prices in export markets.

Box 2.5 ▷ A hybrid case

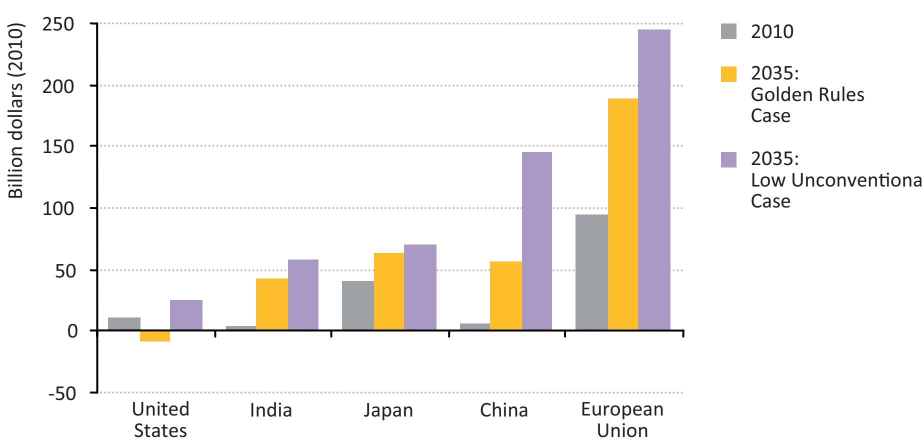
The two cases examined here apply favourable and unfavourable assumptions, respectively and uniformly, to all countries' prospects for unconventional gas development. But it is also possible that some countries follow a path of rapid growth in unconventional resource development along the lines of the Golden Rules Case, while others make slow progress or opt not to develop these resources, as in the Low Unconventional Case. Perhaps the most plausible of these hybrid cases is one in which enhanced attention to environmental issues sustains growth in unconventional output in North America and Australia, while elsewhere – with the partial exception of China – countries fail to realise the regulatory mix that would allow unconventional gas output to grow fast, at least until well into the 2020s. This case is not modelled here, but bears a resemblance to the central scenario of the *WEO-2011* that will be updated in full in this year's *Outlook*, to be published in November 2012.

Investment and other economic impacts

Various constraints in the Low Unconventional Case – moratoria on the use of hydraulic fracturing, overly strict regulation, unreasonably high compliance costs, arbitrary restrictions on drilling locations, less attractive fiscal terms, limitations on water availability and emerging resource limitations – serve to deter upstream investment in unconventional resources. Global cumulative investment in unconventional gas falls by half, to some $1.4 trillion, compared with the investment in the Golden Rules Case, and 60% of investment in unconventional gas is made in the United States. Even so, the share of the United States in global cumulative upstream gas investment declines from 24% to 21%. Limited prospects for unconventional gas prompt $0.7 trillion more cumulative investment in conventional resources. This underscores the relative shift in market power from unconventional resource holders to the major conventional producers, notably in Russia, the Middle East and North Africa.

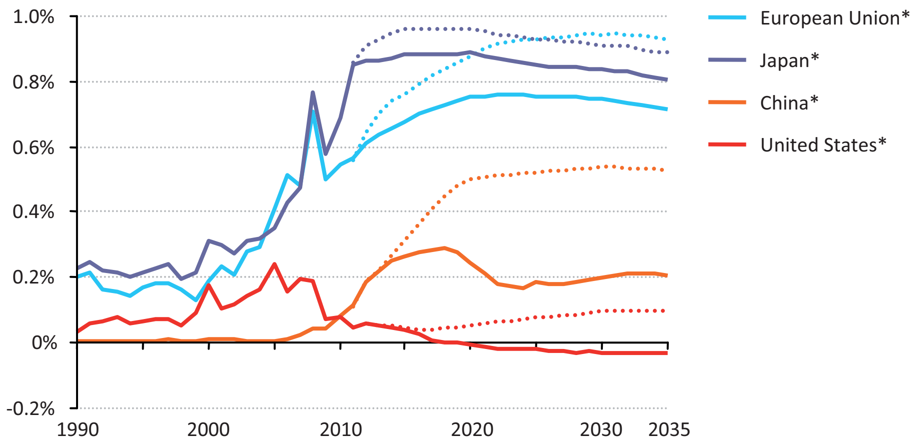
The import bills attached to inter-regional trade rise to $630 billion in 2035 (in year-2010 dollars) in the Low Unconventional Case, nearly 60% higher than in the Golden Rules Case. The proportionate impact on import bills is highest in China and the European Union, but the effect in other countries is also marked (Figure 2.13). China's spending on gas imports in 2035 in the Low Unconventional Case reaches almost $150 billion, or almost three times the level reached in the Golden Rules Case. Gas-import bills in the European Union rise to $245 billion in 2035, 30% above the $190 billion reached in the Golden Rules Case. Spending by the United States on gas imports in 2035 in the Low Unconventional Case totals $25 billion, around double the level of 2010, whereas the United States is a net exporter from 2020 in the Golden Rules Case, with export earnings increasing steadily to around $10 billion in 2035.

Figure 2.13 ▷ Natural gas-import bills by selected region and case



It follows that gas import bills expressed as a share of GDP are also sharply higher in the Low Unconventional Case than in the Golden Rules Case (Figure 2.14). For example, China's import bills stabilise at 0.5% of GDP towards the end of the projection period compared with a plateau of just 0.2% in the Golden Rules Case.

Figure 2.14 ▷ Spending on net-imports of natural gas as a share of real GDP at market exchange rates by case



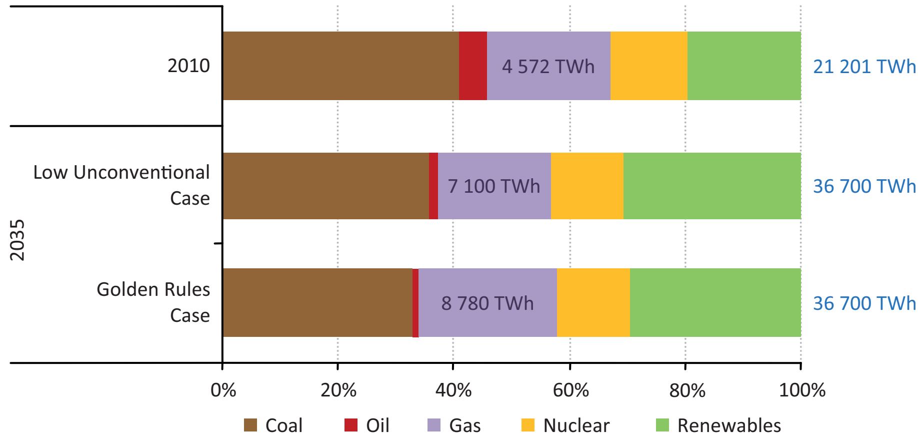
* Solid lines represent the Golden Rules Case; dotted lines represent the Low Unconventional Case.

Climate change and the environment

Although the forces driving the Low Unconventional Case derive in part from environmental concerns, it is difficult to make the case that a reduction in unconventional gas output brings net environmental gains. The effect of replacing gas with coal in the Low Unconventional Case is to push up energy-related CO_2 emissions, which are 1.3% higher than in the Golden Rules Case. The global power generation mix (Figure 2.15) involves a higher share of coal-fired power in the Low Unconventional Case, stemming from the more limited role for natural gas. Additional investment in coal-fired generation locks in additional future emissions, since any new coal-fired power plant has an anticipated operating lifetime in excess of 40 years.

Though many of those concerned with environmental degradation may find it difficult to accept that unconventional gas resources have a place in a sustainable energy policy, a conclusion from this analysis is that, from the perspective of limiting global greenhouse-gas emissions, a Golden Rules Case has some advantages compared with the Low Unconventional Case, while also bringing with it other benefits in terms of the reliability and security of energy supply.

Figure 2.15 ▷ **World power generation mix by case**



Note: TWh = terawatt-hours.

Nonetheless, reaching the international goal of limiting the long-term increase in the global mean temperature to 2°C above pre-industrial levels cannot be accomplished through greater reliance on natural gas alone. Achieving this climate target will require a much more substantial shift in global energy use, including much greater improvements in energy efficiency, more concerted efforts to deploy low-carbon energy sources and broad application of new low-carbon technologies, including power plants and industrial facilities equipped for carbon capture and storage. Anchoring unconventional gas development in a broader energy policy framework that embraces these elements would help to allay the fear that investment in unconventional gas comes at the expense of investment in lower-carbon alternatives or energy efficiency.

Country and regional outlooks

Are we moving towards a world of Golden Rules?

Highlights

- The United States is the birthplace of the unconventional gas revolution and regulatory developments at both federal and state levels will do much to define the scope and direction of similar debates in other countries. Moves are underway to build on existing regulation and practice, for example by tightening the rules on air emissions, ensuring disclosure of the composition of fracturing fluids and improving public information and co-operation among regulators.
- In North America, both Mexico and Canada also have significant unconventional gas resources and Canada is one of only a handful of countries outside the United States where commercial production is underway. Which way the regulatory debate turns could have a substantial effect on future unconventional supply: in the Golden Rules Case, total production from North America reaches 1 085 bcm in 2035, of which almost 70% is unconventional supply, whereas the equivalent figure in the Low Unconventional Case is only 780 bcm; this makes the difference between the region exporting to, or importing from, global gas markets.
- The prospects for unconventional gas in China are intertwined with the much broader process of gas market and pricing reform, and with open questions about the extent and quality of the resource. Over the longer term, environmental policies and constraints, notably water availability, are also set to play a role. Our projections for the Golden Rules Case are for unconventional output to reach just over 110 bcm in 2020, a very rapid increase but still somewhat lower than ambitious official targets, and 390 bcm in 2035. Unconventional production is some 280 bcm lower in 2035 in the Low Unconventional Case.
- In advance of any substantial unconventional output, the regulatory framework in Europe is under examination at both national and EU levels, with a variety of outcomes ranging from enthusiastic support for unconventional development from Poland to the bans on hydraulic fracturing in place in France and Bulgaria. In our projections in the Golden Rules Case, growth in unconventional supply in the European Union reaches almost 80 bcm in 2035, which is sufficient post-2020 to offset the decline in conventional output.
- New unconventional gas projects in Australia are coming under increased environmental scrutiny, in particular related to the risk of water contamination from coalbed methane projects. This could constrain future unconventional gas output, although Australia has ample conventional resources with which to achieve growth in supply and export; exports of 120 bcm by 2035 in the Golden Rules Case come mainly from unconventional gas developments, whereas a comparable level of export in the Low Unconventional Case is driven by mainly by conventional output.

United States

Resources and production

Until recently, unconventional natural gas production was almost exclusively a US phenomenon. Tight gas production has the longest history, having been expanding steadily for several decades. Commercial production of coalbed methane began in the 1980s, but only took off in the 1990s; it has levelled off in recent years. Shale gas has also been in production for several decades, but started to expand rapidly only in the mid-2000s, growing at more than 45% per year between 2005 and 2010. Unconventional gas production was nearly 60% of total gas production in the United States in 2010. While tight gas and shale gas account for the overwhelming bulk of this, shale gas is expected to remain the main source of growth in overall gas supply in the United States in the coming decades. The United States and Canada still account for virtually all the shale gas produced commercially in the world, though – as discussed in Chapter 2 of this report – many countries are now trying to replicate this experience.

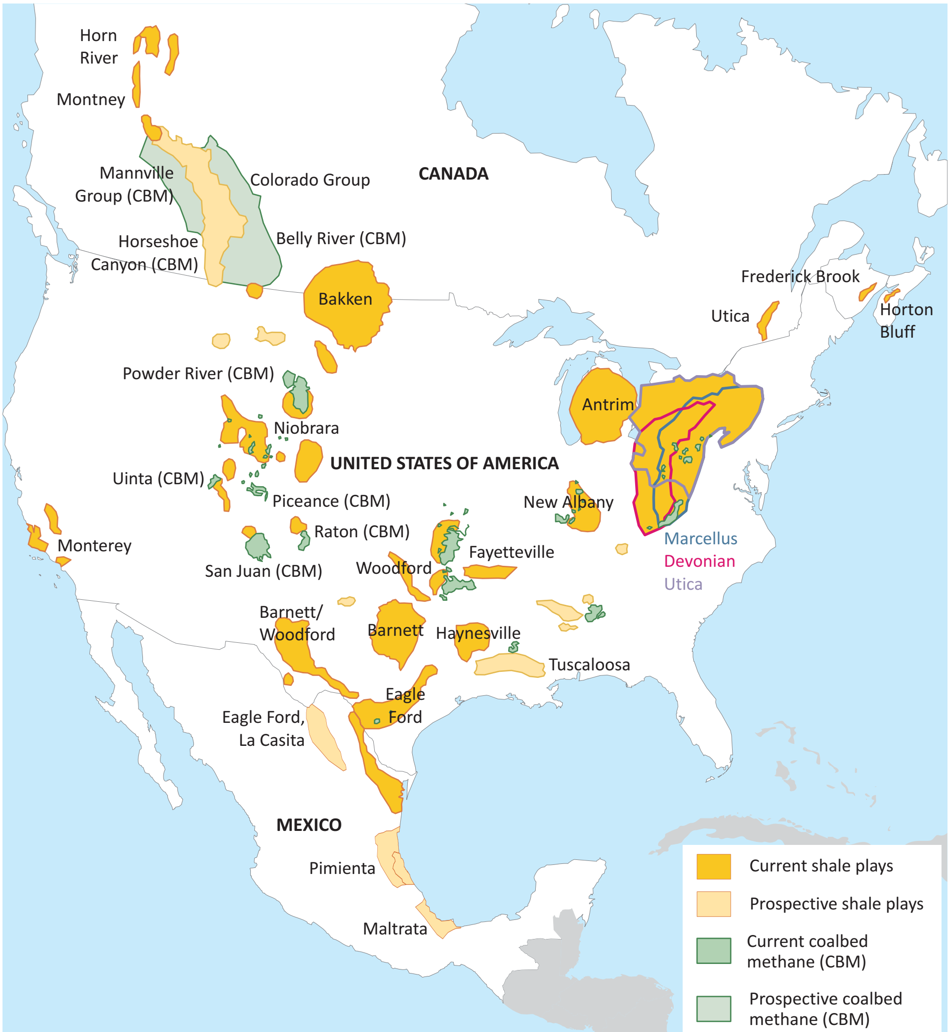
There are large resources of all three types of unconventional gas across the United States. Of the 74 trillion cubic metres (tcm) of remaining recoverable resources of natural gas at end-2011, half are unconventional (Table 3.1); in total, gas resources represent around 110 years of production at 2011 rates. Major unconventional gas deposits in the United States are distributed across much of the country (Figure 3.1). Coalbed methane resources are found principally in the Rocky Mountain states of Wyoming, Utah, New Mexico, Colorado and Montana. Tight gas and shale gas are located in a number of different basins stretching across large parts of the United States, some of which are shared with Canada and Mexico. Two of the largest shale plays that have been identified, the Marcellus and Haynesville formations, taken as single reservoirs are among the largest known gas fields of any type in the world.

Table 3.1 ▷ Remaining recoverable natural gas resources and production by type in the United States

	Recoverable resources (tcm)		Production (bcm)		
	End-2011	Share of total	2005	2010	Share of total (2010)
Unconventional gas	37	50%	224	358	59%
Shale gas	24	32%	21	141	23%
Tight gas	10	13%	154	161	26%
Coalbed methane	3	4%	49	56	9%
Conventional gas	37	50%	288	251	41%
Total	**74**	**100%**	**511**	**609**	**100%**

Sources: IEA analysis and databases.

Figure 3.1 ▷ **Major unconventional natural gas resources in North America**



This document and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Regulatory framework

As pioneers of large-scale unconventional gas development, policy-makers, regulators, producers and the general public in the United States have been the first to face the question of how to evaluate and minimise the associated environmental risks. The emergence of unconventional gas production on a large scale has prompted a broad debate, particularly as production has moved out of traditional oil and gas producing areas. It has also led to changes in the regulatory framework and industry practices. As described in Chapter 1, the principal areas of concern are the impact of drilling on land use and water resources (in particular, the possible contamination of aquifers and surface water) and possible increases in air emissions, particularly of methane and volatile organic compounds.

The legal and regulatory framework for the development of unconventional resources in the United States is a mixture of laws, statutes and regulations at the federal, state, regional and local levels. Most of these rules apply to oil and gas generally and were in place before unconventional resource development took off. They cover virtually all phases of an unconventional resource development, from exploration through to site restoration, and include provisions for environmental protection and management of air, land, waste and water. States carry the primary responsibility for regulation and enforcement on lands outside federal ownership. This approach allows for some regionally specific conditions, such as geology or differing economic or environmental priorities, to be taken into account, with consequential variations in regulatory practices among states. However, on federal lands (extensive in the western United States), the federal government owns the land and mineral resources and directly regulates the extraction process.

Federal laws applicable to unconventional gas resource development are directed mainly at environmental protection. They include the Clean Air Act, Clean Water Act and Safe Drinking Water Act. Certain exemptions from federal rules have been granted; for example, hydraulic fracturing is excluded from the list of regulated activities under the Underground Injection Program authorised by the Safe Drinking Water Act (unless diesel-based fracturing fluids are used). Federal regulations related to community protection and occupational health and safety require that operators make information on certain hazardous chemicals used in drilling operations, including fracturing fluids, available to officials and those responsible for emergency services. Federal rules do not pre-empt additional state-level regulations and public concerns about the risk of pollution have prompted some states to require wider public disclosure about the types and volumes of chemicals used.

State-level regulations relevant to unconventional resources are typically specified in state oil and gas laws; in some cases, these are being updated to respond to public concerns about the environmental impact of unconventional gas development. Typical changes include rules about disclosure of information on fracturing fluids, additional measures to ensure adequate integrity in well casing and cementing, and rules on the treatment and disposal of waste water. Yet regulatory gaps remain in many states, not least because some have limited experience with oil and gas development. The states of New York, New Jersey and Maryland have enacted temporary bans on hydraulic fracturing pending further review of its environmental impacts and the need for changes to regulations; at the time of writing, Vermont also seems set to enact a ban.

Efforts to strengthen the United States' regulatory framework are a public priority, in order to ensure responsible development of unconventional resources and respond to rising public anxiety and pressure. Among the many public organisations focusing on the environmental aspects of unconventional gas development, two are working specifically on improving the quality of regulatory policy: the Ground Water Protection Council and the State Review of Oil and Natural Gas Environmental Regulations (STRONGER). They have both been advising states on regulatory matters to do with unconventional gas. The industry itself has taken steps to promote best practice, both through industry bodies, such as the American Petroleum Institute and through initiatives such as the creation of the FracFocus website, a voluntary online registry to which companies submit data about chemicals used in hydraulic fracturing operations (API, 2011). The site is managed through a partnership with the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission.

The United States Environmental Protection Agency has issued federal regulations under the Clean Air Act that aim to reduce emissions of volatile organic compounds from all operations of the oil and gas industry; these will also cut methane emissions. The regulations apply to wells that are hydraulically fractured and will, in essence, enforce the use of "green completions", as already mandated in Colorado and Wyoming. The Bureau of Land Management, responsible for regulation of most energy-related activities on federal land, has proposed new rules that would require companies to disclose the composition of fracturing fluids, seek additional permits and conduct stringent well integrity tests. These initiatives have sparked an intense debate among interested parties as to whether hydraulic fracturing should be regulated at both state and federal level, and whether harmonised regulations on federal lands and on neighbouring leases are required.

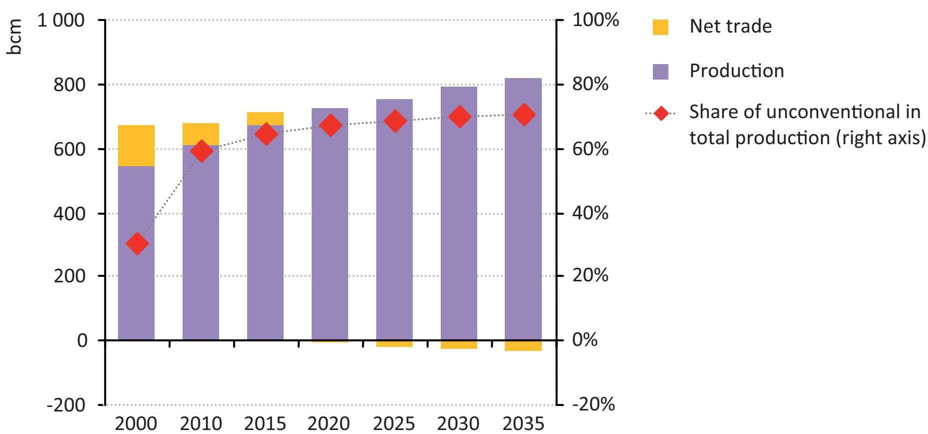
At the end of 2011, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued a set of twenty recommendations for short-term and long-term actions by federal and state agencies to reduce the environmental impact and improve the safety of shale gas production (US DOE, 2011). A major study by the National Petroleum Council on the future of oil and gas resources in the United States has also emphasised the need for "prudent development" and concluded that the benefits of the country's oil and gas resources can be realised by ensuring that they are developed and delivered in a safe, responsible and environmentally acceptable manner in all circumstances (NPC, 2011). These studies and recommendations have been important in defining the scope of regulatory change in the United States and setting its direction; by extension, they could be influential in many countries that are seeking to undertake unconventional gas development.

Within this diverse structure, a major challenge is to maintain reasonable consistency of regulation (for example, among the different states), closing regulatory gaps, where necessary, and doing this in a way that encourages best practice and responds to changes in production technology. Unconventional resource production may be well underway in United States, but shale gas development – and hydraulic fracturing in particular – has become an emotive public issue, with strong and well-organised positions taken by many of the parties involved. This has complicated the prospects for constructive engagement, limiting the common ground on which new regulation (at federal or state level) or new projects (at local level) might be based. Given the scale and pace of development in the United States, there is a likelihood that regulation will be driven by events. For example, an environmental incident linked to unconventional gas development could crystallise public views and prompt new restrictions on unconventional gas production or the use of hydraulic fracturing.

Projections and implications

Assumptions about the regulatory environment have a marked impact on the results of the two cases examined in this report.[1] In the Golden Rules Case, total gas production in the United States grows from around 610 billion cubic metres (bcm) in 2010 to 820 bcm in 2035 (Figure 3.2). Almost all of this increase comes from shale gas production: output of conventional gas, coalbed methane and tight gas remain close to current levels. As a result, the share of shale gas in total gas production rises from 23% in 2010 to 45% in 2035; total unconventional production takes a 71% share of gas output by 2035.

Figure 3.2 ▷ Natural gas balance in the United States in the Golden Rules Case*



* Positive values for net trade denote imports, while negative values represent exports. The sum of production and net trade represents total demand.

In the Low Unconventional Case, total gas production goes into decline after peaking at 660 bcm around 2015, falling to 580 bcm in 2035, 30% less than in the Golden Rules Case (Table 3.2). Production of shale gas in the United States grows until 2017 before limitations on access to resources cause output to fall back to 2010 levels; tight gas and coalbed methane production also decline, to levels seen around 2000 and 1990, respectively. In the Low Unconventional Case, the share of unconventional gas in total supply decreases to only 47% by the end of the *Outlook* period – 23 percentage points less than in the Golden Rules Case. On the other hand, higher gas prices and limited unconventional production in the Low Unconventional Case prompt a mini-renaissance in conventional gas output, with an increase of more than 50 bcm over 2010 production, driven by the investment capital

1. See Chapter 2 for details of assumptions in both cases.

and rigs freed up by the shrinking unconventional sector and the possible opening of more offshore and Arctic acreage as the United States struggles to reduce its imports and the associated bills.

These results point in two very different directions for the United States' domestic consumers of gas and its gas industry and its role in international markets. On the domestic market, although gas prices are set to increase in both cases, the rate of the price increase is moderated in the Golden Rules Case by the availability of domestic unconventional gas. United States gas consumption grows by 0.6% per year in this case, a modest rate of increase by global standards (reflecting the maturity of the gas market), but much more impressive considering that overall energy demand growth in the United States averages 0.1% per year (so gas consumption grows six times faster than overall energy demand[2]). In the United States, IHS Global Insight estimates that the lower gas prices attributable to shale gas production will save households $926 per year between 2012 and 2015 (IHS, 2011). Cheaper gas also stimulates industries – chemicals and fertilisers, in particular – that rely on gas as a key feedstock or source of energy. Several chemical companies have announced expansion plans in the United States (PWC, 2011). In the Low Unconventional Case, gas consumption in the United States grows until 2020 and then declines thereafter, ending almost 15% lower by 2035 than in the Golden Rules Case.

Table 3.2 ▷ Natural gas indicators in the United States by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	609	726	821	637	578	242
Unconventional	358	489	580	383	274	306
Share of unconventional	59%	67%	71%	60%	47%	23%
Cumulative investment in upstream gas, 2012-2035**		1 648		1 293		355
Unconventional		1 308		854		454
Net trade (bcm): net imports (+) / net exports (-)	71	-9	-33	57	97	-131
Imports as a share of demand	10%	n.a.	n.a.	8%	14%	n.a.
Share of gas in the energy mix	25%	26%	28%	25%	24%	4%
Total energy-related CO_2 emissions (million tonnes)	5 343	5 218	4 618	5 173	4 511	108

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

2. This figure for the United States is higher, for example, than the comparable figure for China, where gas demand grows by an average of 7% per year in the Golden Rules Scenario, "only" about four times faster than total energy growth averaging 1.9% per year.

The boom in shale gas thus far has already transformed prospects for gas trade. The future of this unconventional "revolution" will determine whether the United States becomes an influential gas exporter over the coming decades or, alternatively, sees its imports rise from current levels. As recently as 2008, the United States was projected to require increasing imports of liquefied natural gas (LNG) to meet incremental gas demand (US DOE/EIA, 2008). In the Low Unconventional Case, this again becomes a prospect as domestic production declines.

In the expectation of a more favourable outlook for unconventional gas supply, a number of projects have been proposed to convert idle regasification terminals into liquefaction facilities to enable LNG exports (see Chapter 2). The most advanced of these, Sabine Pass on the United States Gulf Coast, cleared the last of its regulatory hurdles in April 2012 and could be exporting as soon as late 2015, with a target throughput of 22 bcm per year. A further seven projects await Department of Energy export approval, totalling in excess of 120 bcm of capacity. While not all these projects will proceed by 2020, even an additional two projects could see United States LNG export capacity exceed 60 bcm by 2020.

The prospect of LNG export has ignited a debate in the United States about the possible impact on price levels, with domestic gas-intensive industrial users expressing concern that they might lose an element of their current competitive advantage. We assume that other LNG export projects besides Sabine Pass are approved to begin operation but, in the Golden Rules Case, because of limited opportunities for export, the additional capacity may not be needed: LNG exports out of North America reach 40 bcm in 2035 but this is split between the United States and Canada. As discussed in Chapter 2, such exports and capacity would nonetheless have significant implications for the structure of international gas markets and for gas security, especially since a part of these exports would be based on a gas-priced formula, derived from the Henry Hub price.

Successfully meeting public concerns by putting in place the regulatory conditions that deal convincingly with environmental risks could be expected to have a significant impact on the pace of development of unconventional gas resources in other parts of the world. The United States has been the testing ground for unconventional gas technology and the place where this technology has been most widely and most productively applied. Just as experience from the United States has prompted both global interest in developing unconventional resources and reservations about their environmental impact, so too will other countries look to the United States for evidence that social and environmental risks can be managed successfully, in part with appropriate regulation.

Canada

Resources and production

Canada is endowed with large unconventional gas resources of all three types and is one of only a handful of countries outside the United States where commercial production is underway. Production of tight gas was around 50 bcm in 2010 and production of coalbed methane (concentrated in the province of Alberta) close to 8 bcm. Shale gas is believed to have the greatest production potential in the longer term, although commercial production is only 3 bcm. The main Canadian shale gas plays currently being explored and appraised are the Horn River Basin and Montney shales in northeast British Columbia, the Colorado Group in Alberta and Saskatchewan, the Utica Shale in Quebec and the Horton Bluff Shale in New Brunswick and Nova Scotia (Figure 3.1). Remaining recoverable unconventional resources in Canada at end-2011 are estimated to be 18 tcm (11 tcm shale gas, 5 tcm coalbed methane and 2 tcm tight gas), representing around 6% of world unconventional resources. 80% of Canada's total remaining recoverable gas resources are unconventional.

Regulatory framework

Unconventional gas in Canada is subject to a set of federal, provincial and local laws and regulations governing upstream activities, including those relating to environmental impacts. Most oil and gas regulations are provincial, as the resources belong to the provinces (with the exception of those on native lands). The National Energy Board is the federal regulatory body for international and inter-provincial energy issues, while Environment Canada is the federal agency responsible for environmental protection, including the administration and enforcement of federal laws.

The regulatory picture in Canada varies by province, but in response to public pressure and the heightened commercial interest in Canadian unconventional gas opportunities, regulators across the country are paying increasing attention to the potential pollution risks from hydraulic fracturing and to the disposal of waste water from unconventional wells. While each province has its own particular regulations, all jurisdictions have laws to protect fresh water aquifers and to ensure responsible development. In western Canada, gas producers are required by regulation to re-inject produced water into deep saline zones located far below the base of the groundwater, using water disposal wells. In other regions, where no such disposal wells are available, provincial regulations set requirements for treating and disposing of produced water.

Approvals for water use are required from the responsible regulatory agency or government department. Regulators and governments have a variety of control mechanisms available to manage water use and mitigate potential impacts, including the ability to limit the rate at which water is used from any source and to specify aggregate water use limits. There are also regulations aimed at minimising the environmental footprint of drilling and production operations, for example by requiring centralised drilling pads and requiring land restoration after production has ceased.

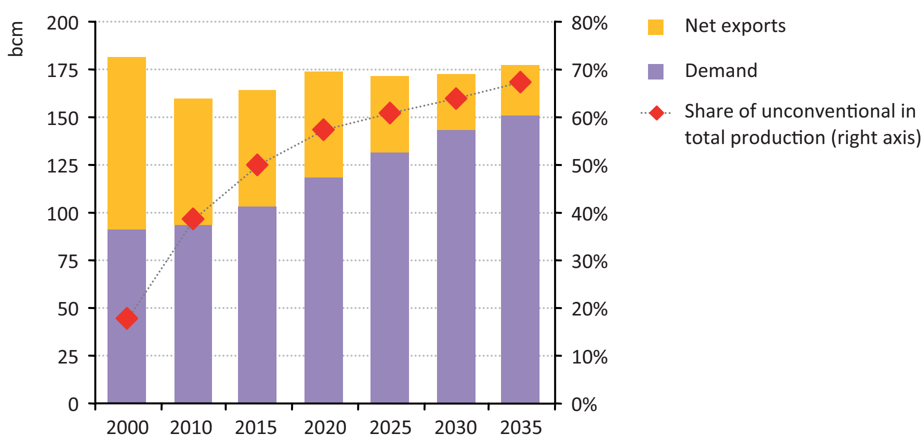
As in the United States, industry bodies are promulgating and promoting best practices. The Canadian Association of Petroleum Producers has recently issued new guidelines for its members, covering many of the issues in the Golden Rules (CAPP, 2012). The Energy Resources Conservation Board, the regulator for the Province of Alberta, a province with a long history of oil and gas production, has initiated a review of its regulatory framework as it applies to unconventional gas (ERCB, 2011). Five of Canada's provinces and one territory are associate members of the United States Interstate Oil and Gas Compact Commission.

The prospect of expanded drilling for shale gas has generated some public and political concern; the clearest incidence of this led the provincial government in Quebec to call a halt in 2011 to the use of hydraulic fracturing, pending an environmental review of the impacts of this practice on water supplies. This followed commercial interest in developing the Utica shale which, running near population centres along the St Lawrence River, generated substantial local opposition. The review is expected to report in 2013.

Projections and implications

Unconventional gas in Canada is expected to play an increasingly important role in offsetting a projected decline in conventional gas production and meeting rising domestic demand. In the Golden Rules Case, unconventional gas production rises from 62 bcm in 2010 to about 120 bcm in 2035, its share of total gas output increasing from just under 40% to two-thirds (Figure 3.3). Shale gas and, to a slightly lesser extent, coalbed methane drive this growth. Total gas production increases from 160 bcm to nearly 180 bcm between 2010 and 2035. Canadian gas demand grows even faster, so net exports drop sharply – from around 65 bcm in 2010 to 25 bcm in 2035. The United States has less need – possibly none at all – to import gas from Canada as its own production of unconventional gas is projected to outpace its domestic gas needs. While Canadian LNG exports to Pacific markets commence before 2020, further growth in exports to Asia is limited in the Golden Rules Case by the large increase in domestic production in China, as well as the rise in unconventional production in Indonesia and Australia.

Figure 3.3 ▷ Natural gas balance in Canada in the Golden Rules Case*



* The sum of demand and net exports represents total production.

In the Low Unconventional Case, shale gas production remains relatively robust, even with the assumed limitations on access to resources. It is about the only unconventional gas resource type with room to grow to offset otherwise rising North American demand for imports. However, overall gas production peaks before 2025 and falls back below current levels by the end of the projection period (Table 3.3). The higher prices that result from slower development constrain demand, which reaches around 130 bcm in 2035, 15% lower than in the Golden Rules Case. Although production is lower in the Low Unconventional Case, it is noteworthy that the required upstream investment is at a level similar to that in the Golden Rules Case; this is because of the relative resilience of shale gas production in the Low Unconventional Case and to the assumption (built into the model) that production tends to become more costly as a given resource starts to become more difficult to access. Since access to shale gas resources is limited in this case, the cost of production rises in a way that balances the effect of lower output on the overall investment requirement.

Table 3.3 ▷ Natural gas indicators in Canada by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	160	174	177	173	141	37
Unconventional	62	100	119	82	84	35
Share of unconventional	39%	57%	67%	48%	60%	7%
Cumulative investment in upstream gas, 2012-2035**		292		296		-4
Unconventional		218		207		11
Net exports (bcm)	66	55	26	63	12	14
Share of gas in the energy mix	30%	34%	40%	32%	35%	5%
Total energy-related CO_2 emissions (million tonnes)	523	547	540	533	521	19

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

Mexico

Resources and production

Mexico's large resources make it one of the most promising countries for shale gas development. Its 19 tcm of shale gas is the fourth-largest shale gas resource base in the world after China, the United States and Argentina; this figure represents some 85% of Mexico's remaining recoverable gas resources. While known about for more than two decades, as elsewhere, shale gas was not considered economically viable to produce until recently.

The government is keen to exploit shale gas resources to boost the country's flagging output of conventional oil and gas. In its National Energy Strategy 2012-2026, for the first time, the Mexican Ministry of Energy has included two scenarios for the development of shale gas: the baseline scenario foresees production of 2 bcm (200 million cubic feet per day [mcf/d]) starting in the Eagle Ford shale play in 2016 and reaching 14 bcm (1 343 mcf/d) in 2026 (Secretaria de Energia, 2012). The "strategy scenario" assumes the additional development of the La Casita shale play, which leads to total shale gas production of 34 bcm (3 279 mcf/d) in 2026.

In line with this strategy, Pemex, the national oil company, is looking in particular at the areas in the north that are extensions of the Eagle Ford shale play (Figure 3.1). Pemex sunk its first shale gas well, Emergente 1, in the Burgos basin in February 2011 and this has been producing at a rate of almost 30 million cubic metres (3 mcf/d). Pemex plans to drill around 175 wells during the period 2011 to 2015 to evaluate reserves and delineate priority areas for development. Pemex also plans to acquire about 10 000 square kilometres of three-dimensional seismic data, which it will use to carry out detailed geological and geochemical modelling studies.

If this exploration effort demonstrates the commercial viability of shale gas production, the large-scale development of these resources would require a huge increase in drilling. Pemex estimates that the development of 8.4 tcm (297 trillion cubic feet) of shale gas – its central estimate of recoverable resources – would call for drilling a total of more than 60 000 wells[3] over the next 50 years, requiring a very large-scale capital investment.

In addition to the need for adequate investment, a number of technical challenges would need to be overcome for this to happen, notably adequate access to water for hydraulic fracturing. Coahuila, where much of the Eagle Ford play is located, is one of Mexico's driest states, with rainfall less than half the national average and all of the surface water rights have already been allocated. Three-quarters of the state's water is used in agriculture for the production of grains and other crops that can survive the desert climate, while the rest is for industrial consumption. Hydraulic fracturing on a large scale would require very careful treatment and recycling of waste water to reduce the need for fresh water. Other hurdles to shale gas development, such as the lack of pipeline infrastructure to deliver gas to market, could complicate operations and make the cost of drilling shale gas wells in Mexico significantly higher than in the United States. A plan to increase the transport and distribution capacity for natural gas is being implemented, including a pipeline that will run close to the main gas-rich areas in the northern parts of the country.

3. Information provided in a presentation by Carlos Morales, Director General, PEMEX Exploration & Production, to the IEA Workshop on Unconventional Gas in Warsaw, 7 March 2012. This appears to be based on an Estimated Ultimate Recovery (EUR) of 5 bcf per well; this is representative of good wells in the United States but could overestimate a likely average EUR per well; if so, the number of wells required to produce this volume of shale gas could be higher.

Regulatory framework

The environmental impact of gas development in Mexico is covered by existing environmental, health and safety laws and regulations. There are no specific national regulations in place yet for shale gas; however, the new National Energy Strategy 2012-2026 recognises that the new targets for shale gas production might require specific regulatory provisions and calls for the future development of an "integrated strategy" for shale gas, addressing environmental, social and financial challenges. This will require not only attention to the regulatory framework, but also the allocation of sufficient resources to regulatory bodies to ensure adequate supervision and enforcement.

Pemex holds monopoly rights over all upstream activities in Mexico and no other company is allowed to own hydrocarbons reserves or undertake exploration or production for its own benefit. A law adopted in 2008 allows Pemex to sign incentive-based development contracts with other companies, though the price paid for services cannot be linked to production: three such contracts for the development of small, mature onshore fields were awarded in August 2011. Larger contracts, which could have a more substantial impact on the country's production, are expected to be offered in future.

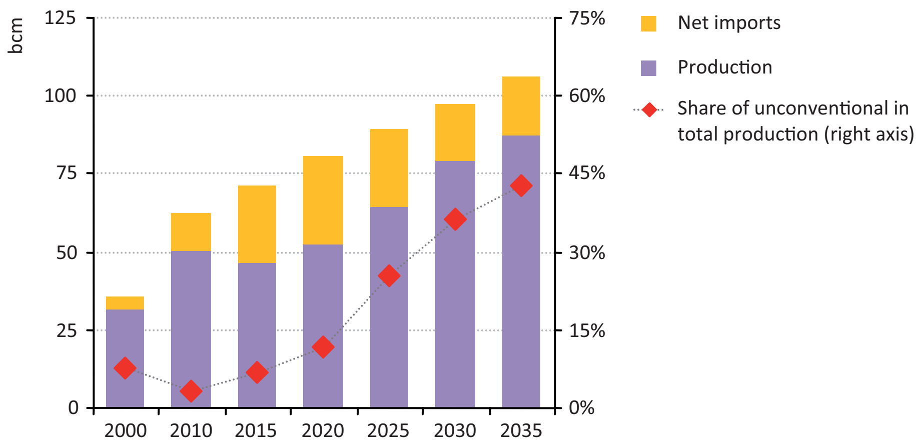
The strategy to be developed for shale gas could follow one of a range of possibilities: it could rest heavily on assistance from companies under service contracts, either basic in terms of remuneration or more strongly incentive-based, although it is also possible that Pemex could decide to handle all shale development on its own. The pace of shale gas development will depend in part on the approach chosen; a greater involvement of private firms, beyond the arrangements already provided for in current legislation, could accelerate the process, but may be politically challenging.

Projections and implications

Shale gas could make a significant contribution to meeting Mexico's gas needs in the longer term, but much will depend on the regulatory regime governing participation by private companies and whether the environmental challenges – notably related to the use and recycling of water for hydraulic fracturing – can be overcome. Development costs will have to be low enough to allow domestic resources to compete with imports from the United States, the price of which recently hit new lows. The alternative – to try and protect the domestic market from cheaper gas imports – is difficult in the context of Mexico's participation in the North American Free Trade Agreement.

In the Golden Rules Case, Mexican gas production grows from 50 bcm in 2010 to almost 90 bcm in 2035, with nearly all of the increase coming from unconventional gas (mostly shale gas, plus some tight gas); conventional gas production grows slightly to around 50 bcm by the end of the projection period, as new fields struggle to compensate for the continuing decline in output from the Cantarell field and other mature fields.[4] Shale and tight gas production reach about 37 bcm combined in 2035, accounting for close to 45% of total Mexican gas production (Figure 3.4). In the Low Unconventional Case, unconventional gas production remains negligible through to 2035.

Figure 3.4 ▷ Natural gas balance in Mexico in the Golden Rules Case*



* The sum of production and net imports represents total demand.

Rapid growth in unconventional gas would have a major impact on Mexico's overall energy mix, with the lower gas prices encouraging gas use and leading to an increase in gas demand. In the Golden Rules Case, demand rises from around 60 bcm in 2010 to 105 bcm in 2035, the share of gas in total primary energy use increasing from 29% to 35% (Table 3.4). The country's need to import gas varies over time. It currently imports about 20% of its gas needs, by pipeline from the United States and in the form of LNG; these imports rise to nearly 30 bcm by 2020, but then fall back to about 20 bcm by 2035 as gas production outstrips demand growth. Higher gas demand and lower imports promise energy security and economic benefits to Mexico, with the possibility of net environmental benefits. In the Low Unconventional Case, the share of gas in primary energy demand actually drops, to 28% by 2035, leading to higher energy-related carbon-dioxide (CO_2) emissions relative to the Golden Rules Case.

4. In the strategy scenario, or high case, included in Mexico's National Energy Strategy 2012-2026, conventional gas production increases from around 60 bcm in 2011 to almost 85 bcm in 2026. Shale gas production, on its own, contributes around 34 bcm to total natural gas production in 2026.

Table 3.4 ▷ Natural gas indicators in Mexico by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	50	52	87	46	59	28
Unconventional	2	6	37	0	0	37
Share of unconventional	3%	12%	43%	0%	0%	43%
Cumulative investment in upstream gas, 2012-2035**		140		111		29
Unconventional		47		-		47
Net imports (bcm)	12	28	19	25	28	-9
Imports as a share of demand	19%	35%	18%	35%	32%	-14%
Share of gas in the energy mix	29%	32%	35%	29%	28%	7%
Total energy-related CO_2 emissions (million tonnes)	402	449	492	455	511	-19

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

China

Resources and production

The size of unconventional gas resources in China is at an early stage of assessment, but it is undoubtedly large. At end-2011, China's remaining recoverable resources of unconventional gas totalled almost 50 tcm, comprised of 36 tcm of shale gas, 9 tcm of coalbed methane and 3 tcm of tight gas.[5] This is around thirteen times China's remaining recoverable conventional gas resources. China's shale gas resources lie in several large basins spread across the country, with plays in the Sichuan and Tarim Basins believed to have the greatest potential. The main coalbed methane deposits are found in the Ordos, Sichuan and Junggar Basins (Figure 3.5).

Coalbed methane is currently the primary source of unconventional gas produced commercially in China, with output of around 10 bcm in 2010. Most of this output comes from coal producers PetroChina and China United Coal Bed Methane Company. Shale gas exploration activities have increased in recent years under a government-driven programme to evaluate the resource base. Results from several pilot projects, to be completed in 2012, are expected to inform the selection of high potential areas for further exploration. As of early 2012, an estimated 20 shale gas wells had been drilled by Chinese companies. Based on what is known about China's geology at this early stage, shale gas resources may prove more difficult and more expensive to develop than those in North America. Early

5. We use the ARI estimate for shale gas to be consistent with our methodology for other countries. This is higher than the 25 tcm estimated by China's Ministry of Land and Resources for recoverable shale gas resources; however the MLR number does not yet include all provinces (MLR, 2012).

indications are that kerogen quality in the shale plays is relatively poor, resulting in low organic content. This suggests that, for China to achieve a similar output to that of the United States, it would need to drill more wells, with longer reach.

Figure 3.5 ▷ Major unconventional natural gas resources in China

This document and any map included herein are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

The Chinese government has outlined ambitious plans for boosting unconventional gas exploration and production. These call for coalbed methane production of more than 30 bcm and for shale gas production of 6.5 bcm in 2015; the targets for shale gas output in 2020 are between 60 and 100 bcm. They are accompanied by the goal to add 1 tcm of coalbed methane and 600 bcm of shale gas to proven reserves of unconventional gas by 2015. In support of this effort, China plans to complete a nationwide assessment of shale gas resources and build nineteen exploration and development bases in the Sichuan Basin in the next four years. Efforts are also supported by the international partnerships that Chinese companies have formed in North America to develop shale gas acreage, which will provide valuable development experience.

An initial tender for four blocks of shale gas exploration acreage in the Sichuan Basin was held in June 2011, with participation limited to six eligible state-controlled companies. Of those, Sinopec and Henan Provincial Coal Seam Gas Development and Utilization Company obtained licences. An expanded group of bidders, including privately-owned Chinese companies (qualified based on sufficient capital, technology and expertise), are expected to participate in a second round of licensing in mid-2012. Foreign firms will not be allowed to participate directly, but may enter into partnerships with eligible companies that submit successful bids. Various major international oil companies have already entered into some form of partnership with state-controlled companies, reflecting their strong interest in pursuing unconventional gas development opportunities in China.

Regulatory framework

China's huge unconventional gas potential and strong policy commitment suggest that these resources will provide an increasingly important share of gas in the longer term, though the pace of development through to 2020 – the key period of learning – remains uncertain. Because of China's highly centralised regulatory and policy-making framework and the high priority placed on industrial and economic development, unconventional gas projects may face fewer hurdles stemming from environmental concerns than those in Europe or the United States. Nonetheless, the regulatory framework is evolving, and different features of it could affect the pace of development in different ways, for example the terms of access, the pace of diffusion of advanced technology, financial incentives, the pricing regime, environmental constraints and infrastructure development.

Strategic policy decisions in China relating to resource management and environmental protection are made nationally, with implementation and enforcement responsibilities often delegated to local authorities. Many aspects of China's legal and regulatory framework for oil and gas development are broadly defined, giving local regulators latitude to consider project-specific circumstances in their decisions (although this can also lead to unpredictable outcomes). Challenges arise from the fragmentation and overlap of responsibilities among various regulating entities, uncertainty about effective co-ordination between them and potentially inconsistent enforcement of regulations.

Domestic petroleum exploration and development has traditionally been the domain of China's state-owned enterprises. Under the Law on Mineral Resources, only state-controlled entities may acquire mineral rights, foreign companies being confined to minority partnerships with state-controlled entities and, in some cases, production-sharing agreements. Although the strategic importance of unconventional gas means that China's national oil companies are likely to be the primary drivers of production growth, there are some changes underway in response to China's ambitious plans for shale gas exploration and development, and the need for the advanced technology and investment that foreign companies can bring. The legal classification of shale gas as a separate "mineral resource" in late 2011 means that the current regulations that give CNPC and SINOPEC exclusive rights for exploration of onshore oil and gas resources do not apply to shale gas, and this step may presage an intention to grant greater access to others. Foreign companies have already been allowed to take a majority stake in coalbed methane projects.

All project promoters must conduct an environmental impact assessment, which must be filed with national and local regulators and approved in advance of submission of a field-development plan. Drilling permits are issued on the basis of the development plan, rather than well-by-well; and any significant changes to the plan, for example related to the density of drilling, require submission of a new environmental impact assessment. Project delays during the early phases of development may occur because of the limited experience of producing unconventional gas in China.

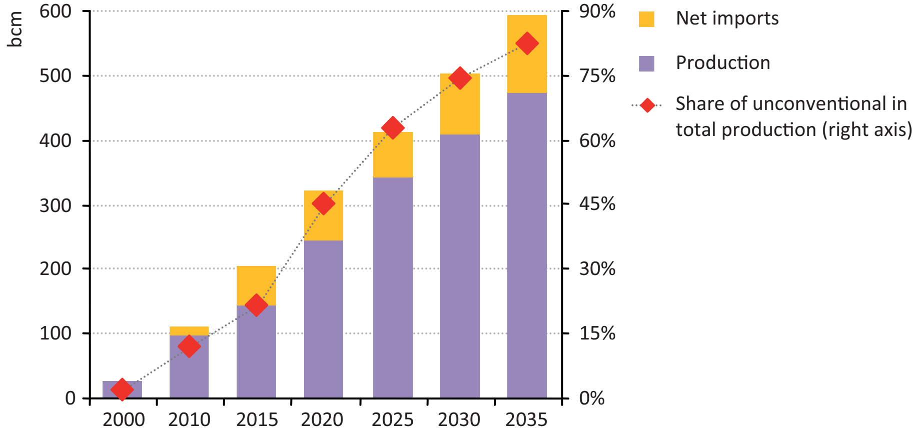
Water availability may prove to be one of the biggest obstacles to unconventional gas development in China, particularly in the north and west, where water is scarce and may be already strained by agricultural or urban needs. Water policies, regulations and plans are determined nationally, though responsibilities for management and enforcement are delegated locally. Many different entities are involved at the national, regional and local levels, which risks limited co-ordination of water resources at the river basin level. National standards establish maximum discharge concentrations for pollutants into water sources and the Circular Water Law promotes reuse and recycling of waste and produced water.

The fiscal regime, gas pricing policies and pipeline access are other regulatory variables that will critically influence the pace of unconventional gas development in China. The 12th Five-Year Plan promises favourable fiscal incentives to producers, namely direct subsidies, preferential tax treatment and priority land use. The domestic coalbed methane industry receives price subsidies of RMB 0.2 ($0.03) per cubic metre for extracted gas and RMB 0.25/m^3 ($0.04) for gas produced for some specific end-users. Shale gas might be expected to attain a similar or higher level of subsidy. According to the 12th Five-Year Plan, the pricing regime for shale gas will be market-based, an important signal that the government is willing to allow higher end-user prices (relative to current controlled prices for natural gas) to encourage development. China's gas pipeline network will necessarily have to expand to reach into unconventional gas production areas in order to avoid becoming a bottleneck as output increases. As major gas pipelines are currently run by national oil companies, making access more available to other producers will be vital.

Projections and implications

Gas is set to play an increasingly important role in meeting China's burgeoning energy needs and the successful development of the country's unconventional resources could accelerate that trend, given effective resource and environmental management. In the Golden Rules Case, unconventional gas production is projected to jump from 12 bcm in 2010 to just over 110 bcm in 2020 and 390 bcm in 2035. Total gas production rises from just under 100 bcm in 2010 to nearly 475 bcm in 2035 (Figure 3.6). Unconventional gas accounts for 83% of total gas production by the end of the projection period. Unconventional gas production in 2035 is predominately from shale gas (56%) and coalbed methane (38%); tight gas (6%) takes a smaller share.

Figure 3.6 ▷ **Natural gas balance in China in the Golden Rules Case***



* The sum of production and net imports represents total demand.

Table 3.5 ▷ **Natural gas indicators in China by case**

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	97	246	473	139	194	279
Unconventional	12	112	391	37	112	279
Share of unconventional	12%	45%	83%	27%	58%	25%
Cumulative investment in upstream gas, 2012-2035**		554		311		243
Unconventional		374		170		204
Net imports (bcm)	14	77	119	143	262	-143
Imports as a share of demand	12%	24%	20%	51%	57%	-37%
Share of gas in the energy mix	4%	8%	13%	7%	10%	3%
Total energy-related CO_2 emissions (million tonnes)	7 503	9 792	10 449	9 877	10 695	-246

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

In the Low Unconventional Case, output of shale gas and coalbed methane grows much less rapidly, reaching a combined level of less than 115 bcm in 2035 (Table 3.5). The reduced availability of local gas supplies increases the country's dependence on imports at higher average prices. Less ambitious policies to boost demand, coupled with higher prices, lead to slower growth in Chinese gas demand, as the Chinese authorities seek to limit the country's reliance on imports. Demand reaches only 455 bcm by 2035, almost one-quarter lower than in the Golden Rules Case. The share of gas in total primary energy is correspondingly markedly lower: 10% versus 13% in 2035. This results in increased dependence on coal and, to a lesser extent, on nuclear and renewables.

Rapid growth in unconventional gas would greatly strengthen China's energy security and have major implications for international gas trade. In the Golden Rules Case, imports amount to nearly 120 bcm in 2035, about 20% of the country's gas demand, compared with just over 260 bcm or nearly 60% of demand in the Low Unconventional Case. The overall cost of gas imports is correspondingly much lower, by 60%, in the Golden Rules Case. Lower import volumes would improve China's negotiating position *vis-à-vis* its suppliers, including producers of LNG, existing suppliers by pipeline from Central Asia and Myanmar, and Russia, which has the potential to become a major supplier of gas to China but whose opportunities to do so would be much more limited in the Golden Rules Case. The uncertainty surrounding the prospects for China's unconventional gas industry may favour investment in LNG over pipeline projects (and, in both cases, lessen the attractiveness of large long-duration supply contracts) as China may seek more flexibility to allow for gas-import needs turning out to be smaller than expected.

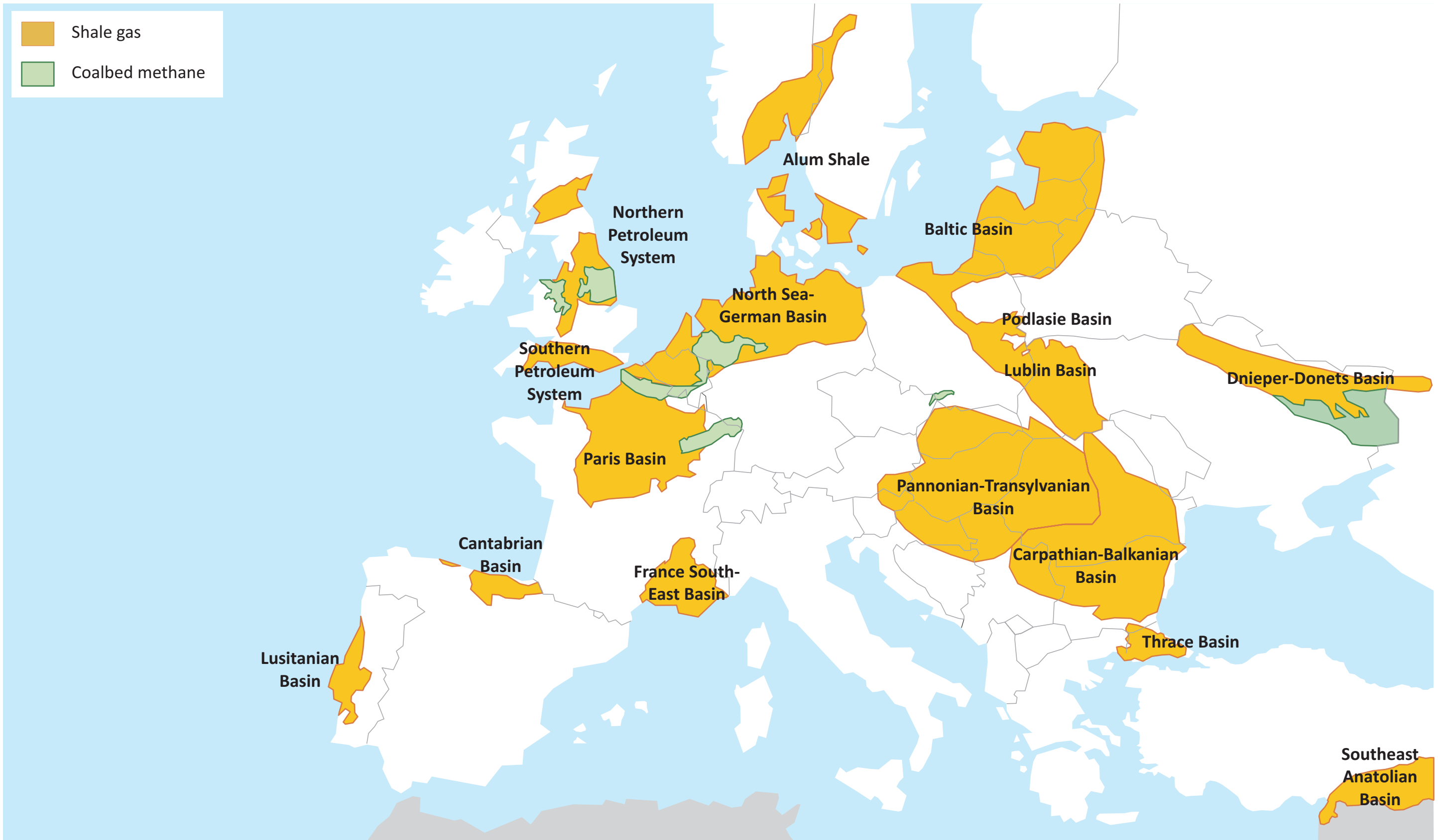
Europe

Resources and production

Europe's unconventional gas resources have attracted considerable interest in the last few years, although in practice the push to develop this resource varies considerably by country, depending on the mix of domestic fuels and imports and perceptions of the risks to energy security and the environment. Attention to unconventional gas focused initially on coalbed methane and tight gas, but has now switched to shale gas. Recoverable resources of shale gas are believed to be large, though how much can be recovered economically remains uncertain.

Europe's shale gas resources are found in three major areas that contain multiple basins, sub-basins and different plays: from eastern Denmark and southern Sweden to northern and eastern Poland (including Alum shales in Sweden and Denmark, and Silurian shales in Poland); from northwest England, through the Netherlands and northwest Germany to southwest Poland; and from southern England through the Paris Basin in France, the Netherlands, northern Germany and Switzerland (Figure 3.7). Poland and France are thought to have the largest shale-gas resources, followed by Norway, Ukraine, Sweden, Denmark and the United Kingdom. Potential coalbed methane resources in Europe are reasonably well established and are significant in some countries, notably in Ukraine, the United Kingdom, Germany, Poland and Turkey.

Figure 3.7 ▷ Major unconventional natural gas resources in Europe



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As yet, there is no large-scale production of unconventional gas in Europe. How soon it will begin and how quickly it will grow remain to be seen, though there are several factors favouring development. The European Union is the second-largest regional gas market in the world, with demand amounting to around 550 bcm in 2010, and it is set to become increasingly dependent on imports as indigenous production of conventional gas continues to decline and demand continues to expand. The region has a well-established pipeline and storage network (albeit not as densely developed as in the United States). And, crucially, natural gas prices are high compared with North America, adding to the attractiveness of developing new indigenous gas resources.

But there are above-ground factors that are likely to impede rapid growth in unconventional gas production, the most significant of which is the high population density in many of the prospective areas. This increases the likelihood of opposition from local communities, especially in areas with no tradition of oil and gas drilling. State ownership of oil and gas rights can also reduce the incentives for communities to accept development of local unconventional gas resources, compared with parts of the United States where these rights are held by private land-owners.

The European regulatory framework

Most regulations applicable to upstream oil and gas in the European Union are determined at the national level: member states define their own energy mix and make decisions concerning domestic resource development. At the EU level, there is a common set of rules (under the Hydrocarbons Licensing Directive) to secure transparent and non-discriminatory access to the opportunities for exploration, development and production of hydrocarbons, but the main area in which Europe-wide regulation applies is environmental protection, including:

- Water protection (Water Framework Directive, Groundwater Directive and Mining Waste Directive).
- The use of chemicals (under REACH regulation, administered by the European Chemicals Agency).
- The protection of natural habitats and wildlife.
- Requirements to carry out an environmental impact assessment, under general environmental legislation.
- Liability for upstream operators to incur penalties for environmental damage (under the Environmental Liability Directive and the Mining Waste Directive).

Public concerns about the environmental risks associated with hydraulic fracturing have prompted calls for new regulation on aspects of this practice, often based on the "precautionary principle" that is a statutory requirement in European Union law. A 2011 report commissioned by the Directorate General for Energy of the European Commission found that European environmental legislation applies to all stages of unconventional gas developments. It also concluded that, both on the European level and at the national level (in the countries studied), there are no significant gaps in the legislative framework when it comes to regulating shale gas activities at the present level of intensity (Philippe & Partners, 2011). However, it did suggest that the situation might change if activities were to expand significantly and did suggest some improvements to national legislation, including procedures to include local citizens at earlier stages in the impact assessment process.

Additional assessments of various aspects of unconventional gas are currently being carried out within the European Commission. These include: a study on the economics of shale gas, by the Joint Research Centre in collaboration with the Directorate General for Energy; a study on methane emissions, by the Directorate General for Climate Action; and an assessment of the adequacy of the current regulatory framework to ensure an appropriate level of protection to the environment and to human health, by the Directorate General for the Environment. On the basis of the results of these assessments, the Commission will decide whether to put forward regulatory proposals specifically related to unconventional gas.

The European Parliament has also taken up the debate about various aspects of shale gas development. An assessment presented to the Committee on Environment, Public Health and Food Safety (European Parliament, 2011a) found that the current regulatory framework concerning hydraulic fracturing has a number of deficiencies, most importantly, the high threshold before an environmental impact assessment is required[6]; it also called for the coverage of the Water Framework Directive to be re-assessed focusing on the possible impacts of hydraulic fracturing on surface water and urged consideration of a ban on the use of toxic chemicals. A draft report to the same committee, prepared by a Polish parliamentarian, is more supportive of unconventional gas development (European Parliament, 2011b), while recognising the need to address concerns about the environmental effects of extraction. A separate draft report, focusing on the energy and industrial implications of shale gas development, is also under consideration by the Parliament's Committee on Industry, Research and Energy (European Parliament, 2012).

Poland

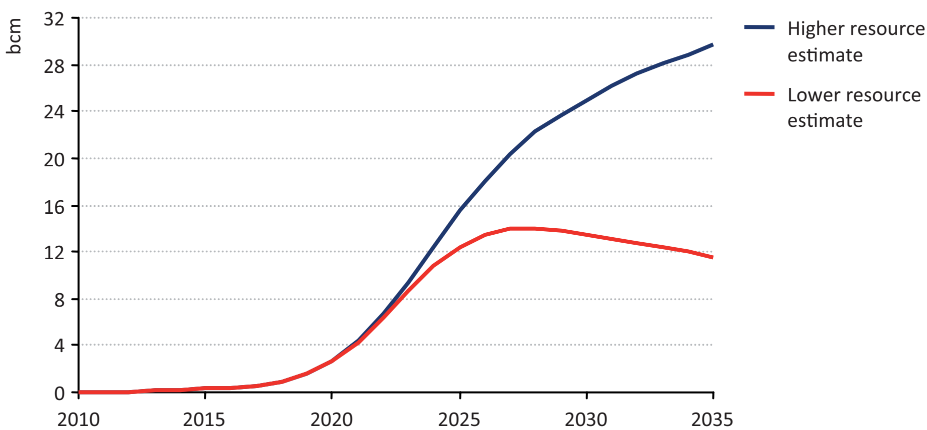
Medium-term prospects for unconventional gas production in Europe appear brightest in Poland, where exploratory drilling for shale gas is most advanced and where above-ground factors are generally less of an obstacle to development than elsewhere. Optimism about Poland's shale gas potential stems from the size of its resources, although these are still subject to considerable uncertainty. The US EIA put technically recoverable resources in Poland at 5.3 tcm (US DOE/EIA, 2011), while an assessment by the Polish Geological Institute (with the support of the United States Geological Survey), studying archive data on the Baltic, Podlasie and Lublin Basins, estimated recoverable resources at 346 bcm to

6. The Environmental Impact Assessment Directive does though include an obligation to screen for possible adverse environmental effects in projects which fall below any relevant thresholds.

768 bcm (PGI, 2012). The large difference is explained primarily by differences in methodologies between the two studies; the range of resource assessments should narrow as more data become available from exploratory drilling.

As described in Chapter 2, the model used for the projections in this report relies on the Rogner and ARI estimates for shale gas resources, which are so far the only assessments that apply a consistent methodology across a large enough number of countries. If actual resources in Poland are significantly lower than assumed, inevitably this would have a considerable impact on our projections, all else being equal. This is illustrated in Figure 3.8, which shows projections for shale gas production in Poland for a higher and lower recoverable resource estimate, respectively, based on the ARI estimate of 5.3 tcm and using a mid-range figure of 0.55 tcm from the Polish Geological Institute estimate.

Figure 3.8 ▷ Impact of different resource assessments on projected shale gas production in Poland



Poland has one of the oldest petroleum industries in the world and has been producing oil and gas from conventional reservoirs since the 1850s, though production has fallen to low levels over recent decades. Interest in shale and tight gas began towards the end of the last decade. A series of exploration licensing rounds has led to a large influx of international companies, with a number of firms that are already active in the United States – including ExxonMobil, Chevron, Eni, Talisman and Marathon – buying up drilling rights, either directly or through joint ventures (although the national oil and gas company, PGNiG, holds the most licences). Over 100 exploration licences, most of which have a duration of five years, have so far been issued, covering most of the prospective shale gas areas.

Early results from exploration drilling have put something of a damper on the initial hopes for a rapid take-off in production. Since PGNiG completed Poland's first shale well in 2009, 18 exploration wells have been drilled, with a further 14 underway and 39 planned (as of March 2012). Flow rates were low in the few wells for which data have been made public, with some reportedly proving unresponsive to normal drilling and well-completion techniques. ExxonMobil has announced that two wells that it drilled and completed in 2011 are not commercially viable, though it is looking into whether different fluids, proppants or pumping techniques might produce better results. ExxonMobil and other companies continue to drill new wells.

The Polish government has been very supportive of drilling for shale and tight gas, reflecting the potentially large economic and energy security benefits that could be gained from supplementing the country's dwindling resources of conventional gas and reducing its heavy dependence on gas imports from Russia. Gas demand is expected to grow in the coming years, particularly for power generation, as older, low-efficiency coal-fired stations close. Although shale gas production costs are likely to be above those in the United States, high oil-indexed prices for imported gas should make shale developments profitable. Relatively low population density in the main basins as well as a history of oil and gas activities may favour public acceptance.

The regulatory framework applicable to unconventional gas development is changing with the prospect of commercial production. Until the recent arrival of foreign firms, the upstream sector was dominated by PGNiG, which ensured that the government captured a large part of any rent on hydrocarbons production and reduced the need for explicit regulation for that purpose. The legislative system for the upstream is now being adjusted to the reality of many new market entrants and participants, including changes to the licensing system and the fiscal framework for upstream activity.

A new Geological and Mining Law came into force in Poland at the start of 2012, which clarifies some administrative and legal questions regarding the development of Poland's unconventional gas potential. The most significant change was that licences for exploration of hydrocarbons in Poland can now be granted only through tenders (exploration licences issued over the last five years were on a first-come, first-served basis). Since most prospective gas exploration acreage in Poland has already been awarded, the new regulations will become more significant when the first production licences are sought. The new law also modifies the system of mineral rights ownership, more clearly defining the division between state rights and those of landowners, but shale gas, as a strategic mineral, remains the exclusive property of the state.

France

With resources almost as large as those in Poland, France was expected to be one of the first European countries to produce unconventional gas commercially. Shale gas potential is primarily in two major shale basins: the Paris Basin and the Southeast Basin. The Southeast Basin is considered to be the more prospective, in view of the low depth of parts of the basin, possible liquids content and low levels of clay. The government had issued three licences for shale gas exploration drilling in the Southeast Basin but, in May 2011, in the face of a strong public opposition over the potential environmental impacts of hydraulic fracturing, the government announced a moratorium on its use and later prohibited it by law. Two firms that held licences – France's Total and the US-based Schuepbach Energy – subsequently had their licences cancelled. Schupebach Energy had maintained their intention to use hydraulic fracturing, whereas Total had submitted a report where they committed not to use it. A third company that committed not to use hydraulic fracturing has had its permit maintained.

Public opposition was linked to the fact that part of the prospective basin underlay scenic regions that are heavily dependent on the tourism industry. Resentment was exacerbated by a lack of public consultation: under French mining laws, public consultation is required only at the production stage and not at the exploration stage. Revision of the mining code is under consideration to include earlier public consultation.

A report was commissioned jointly by the Ministry of Ecology and Sustainable Development and the Ministry of Industry, Energy and Economy to provide information on shale gas and light tight oil, the environmental concerns surrounding their development and the applicability of existing hydrocarbon regulation in France to this new potential energy source. A preliminary report recommended some drilling in France, under strict controls, while more information was gathered about the impact of hydraulic fracturing elsewhere in Europe and the United States (Leteurtrois, 2011). However, the final report was not issued because the ban on hydraulic fracturing was voted in the meantime.

In France, as in some other countries, the debate around shale gas developments became a proxy for a much broader question about the approach to sustainable energy policy. In a separate report prepared for the National Assembly, the co-authors did not share a common vision of France's future energy mix, writing two separate conclusions (Gonnot, 2011). One concluded that more study was required to understand the extent of the country's resource and the technologies to safely develop it, with a view to then taking a decision on whether to proceed developing the resources. The second asserted that the development of new hydrocarbon resources has no place in a national energy policy striving to meet agreed climate change objectives.

The Paris Basin has a long history of conventional oil production. In the early 1980s, high hopes were held that significant volumes might be found, but exploration turned out to be disappointing and production has not exceeded a few thousand barrels per day. Production is mostly from the rural Seine et Marne Région, southeast of Paris, where several hundred wells have been drilled. Some geologists have argued recently that the reason large oil fields have not been discovered is that the hydrocarbons have not been expelled from the source rocks. Indeed, there are indications from wells that have intercepted some of the shales that they may be hydrocarbon bearing, probably mostly light tight oil, with some shale gas. Estimates of oil-in-place vary from 1 to 100 billion barrels, though the fraction which might be technically and economically recoverable is not known.

In the Golden Rules Case, we assume a reversal of the ban on hydraulic fracturing. Shale gas production rises after 2020 to reach 8 bcm in 2035, which would allow France to exceed its peak gas production from the end of the 1970s. At the same time, light tight oil production could reach several tens of thousands of barrels per day. Some of the resources, located in sensitive areas, are likely to remain barred from development but, if productivity can be established, there should be enough resources in other areas to sustain such production.

Other EU member countries

3

There has been a good deal of discussion about unconventional gas prospects in several other EU member countries, but little exploration activity as yet. Most of the wells that have been drilled are for coalbed methane. There appears to be significant potential for shale gas development in several other EU member countries, notably in Sweden, the United Kingdom and Germany.

Sweden's shale gas resources are located in the Scandinavian Alum shale, which extends from Norway to Estonia and south to Germany and Poland. The Alum shale has been mined for oil shale for many decades in central and southern Sweden (and in Estonia), where it is close to the surface. It has the advantages of high organic content and thermal maturity and is relatively shallow, with depths averaging less than 1 200 metres. But it lacks overpressure and contains a high concentration of uranium, which poses problems for water treatment and recycling. Shell has been most active in assessing the shale, having drilled three exploration wells in the Skåne region of southern Sweden, but it ceased operations when they proved to be dry. Opposition to hydraulic fracturing had delayed the programme and threatens to deter renewed exploration activity.

In the *United Kingdom*, a main shale play is the Bowland shale formation (in the Northern Petroleum System), which is relatively shallow, with an average depth of only 1 600 metres, and with certain areas rich in liquids. Cuadrilla Resources has drilled two exploration wells, one of which encountered gas. It subsequently announced that the formation could hold as much as 5.7 tcm (200 trillion cubic feet) of technically recoverable gas. However, operations have been suspended as a result of two small earthquakes that occurred after hydraulic fracturing was carried out. A report commissioned by Cuadrilla concluded that it is "highly probable" that the fracturing and subsequent earthquakes were linked, although future occurrences should be rare given the unique local geology at the well site (de Pater and Baisch, 2011). The UK Department of Energy and Climate Change commissioned an independent report on the causes of the earthquakes and appropriate means of mitigating seismic risks (Green, Styles and Baptie, 2012). It recommended cautious continuation of Cuadrilla's hydraulic fracturing operations and several safety provisions, including greater use of micro-seismic monitoring and new safeguards that would lead to a suspension of operations in case of seismic activity. At the time of writing, the government was awaiting comments on this report before making any decision regarding additional hydraulic fracturing.

The UK government appears to be supportive of continuing shale gas exploration and development. A parliamentary inquiry in 2011 found no evidence that hydraulic fracturing poses a direct risk to underground water aquifers, provided the drilling well is constructed properly, and concluded that, on balance, a moratorium on shale gas activity in the United Kingdom is not justified or necessary at present (UK Parliament, 2011). Nonetheless, the inquiry urged the UK Department of Energy and Climate Change to monitor drilling activity extremely closely in its early stages in order to assess its impact on air and water quality.

Germany has shale resources, estimated at 230 bcm, in the large North Sea-German basin, which extends from Belgium to Germany's eastern border along the North Sea coast. Several companies have acquired exploration licences and ExxonMobil has drilled at least three exploratory shale gas wells in Lower Saxony as part of a ten-well programme. Germany has a history of tight gas production with relatively large hydraulic fracturing treatments having been common practice for the last 20 years. As in France, there has been strong opposition to shale gas drilling on environmental grounds, but attention to the need for indigenous energy sources, including unconventional gas, has been intensified by a decision to phase out nuclear power.

Shale gas exploration efforts are advancing elsewhere in the European Union: there are plans by OMV to drill several test wells in *Austria* in the next two years; in *Lithuania*, exploration licences were being tendered at the time of writing. *Bulgaria* and *Romania* have awarded shale gas exploration licences, but these countries have experienced strong public opposition over fears about the environmental impact of hydraulic fracturing and, in Bulgaria, this has led to parliament voting in early 2012 to ban the use of the technique, making it the second country in the European Union to do so.

EU projections and implications

Against a backdrop of declining indigenous production and a policy priority to diversity sources of gas supply, the European Union has reasons to be interested in exploiting its domestic unconventional gas potential. At the same time, environmental concerns could easily delay or derail development. In our projections in the Golden Rules Case, unconventional gas production is slow to take off but accelerates in the longer term, as confidence grows in the effective application of the Golden Rules in the most prospective countries. In our projections, unconventional production in the European Union climbs to just over 10 bcm by 2020, but it grows more rapidly thereafter, reaching almost 80 bcm by 2035 (Table 3.6). Shale gas accounts for the bulk of this output. Unconventional gas contributes almost half of the European Union's total gas production and meets just over 10% of its demand by 2035. As a result, even though there are not dramatic shifts in the trade balance, as seen in the United States, growth in unconventional production offsets continued decline in conventional output from 2020 (Figure 3.9).

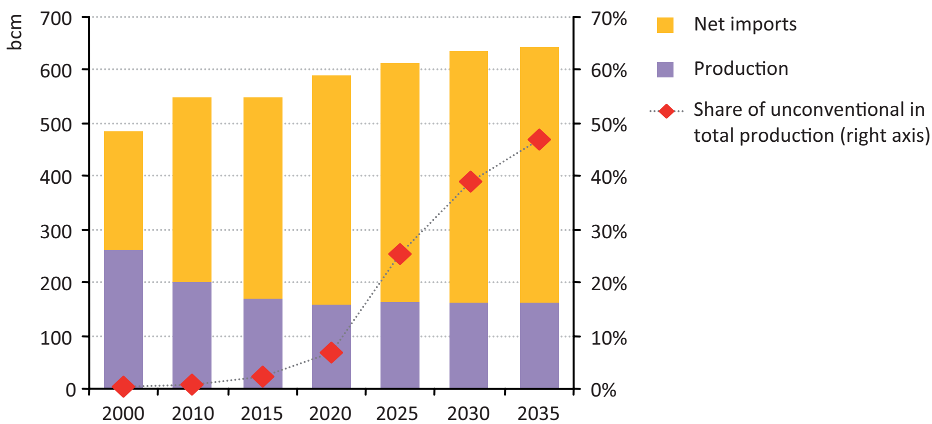
Rising unconventional gas production (both in Europe and worldwide) helps to restrain the rise in gas prices in Europe, which – together with additional policies to encourage gas use – drives up gas demand. As a result, the upward trend in net gas imports into the European Union continues throughout the projection period, reaching 480 bcm in 2035, or three-quarters of total demand (compared with 345 bcm, or more than 60%, in 2010). In the Low Unconventional Case, in which there is very little commercial unconventional production before 2035, European Union net gas imports are 30 bcm higher in 2035 than in the Golden Rules Case (and gas import prices are higher). Consequently, the cost of those imports reaches about $250 billion in 2035 (in year-2010 dollars) – an additional import bill of almost $60 billion relative to Golden Rules Case.

Table 3.6 ▷ Natural gas indicators in the European Union by case

		Golden Rules Case		Low Unconventional Case		Delta*
	2010	2020	2035	2020	2035	2035
Production (bcm)	201	160	165	139	84	81
Unconventional	1	11	77	0	0	77
Share of unconventional	1%	7%	47%	0%	0%	47%
Cumulative investment in upstream gas, 2012-2035**		434		235		199
Unconventional		181		-		181
Net imports (bcm)	346	432	480	423	510	-30
Imports as a share of demand	63%	73%	74%	75%	86%	-11%
Share of gas in the energy mix	26%	28%	30%	26%	28%	2%
Total energy-related CO_2 emissions (million tonnes)	3 633	3 413	2 889	3 414	2 873	16

* Difference between the Golden Rules Case and the Low Unconventional Case. ** Investment figures are in billions of year-2010 dollars.

Figure 3.9 ▷ Natural gas balance in the European Union in the Golden Rules Case*



* The sum of production and net imports represents total demand.

Ukraine

Ukraine has considerable unconventional gas potential in the form of coalbed methane in the main coal-mining areas of eastern Ukraine and in two shale gas basins: a portion of the Lublin Basin, which extends across from Poland, and the Dnieper-Donets Basin in the east.

Coalbed methane resources are estimated at close to 3 tcm. Technically recoverable shale gas resources in Ukraine are 1.2 tcm, around one-third less than remaining recoverable resources of conventional gas. The Ukrainian section of the Lublin Basin is large and reportedly has higher average total organic content than the Polish section and lower average depth. The Dnieper-Donets Basin – which currently provides most of the country's conventional oil, gas and coal production – also has high organic content, but is deeper.

The government is keen to develop new sources of gas in order to reduce the country's heavy dependence on imports from Russia – it has set a target of producing 3 to 5 bcm of unconventional gas by 2020. Coalbed methane is the most likely source of unconventional production growth in the short to medium term, but, if the conditions are in place, shale gas also offers considerable promise. A new tender for two large shale gas blocks in both basins is underway, offering foreign companies the opportunity to bid for the right to enter a production-sharing contract. Naftogaz, the state-owned oil and gas company, signed a memorandum of understanding with ExxonMobil in 2011 to co-operate on shale gas exploration; other companies are also interested in Ukraine's potential. An earlier shale gas tender led to some exploration drilling. Hawkley, an independent Australian company, drilled a shale gas well in the Dnieper-Donets basin in 2011. Kulczyk Oil, an international upstream company, announced in November 2011 that it had successfully completed the hydraulic fracturing of a well in a previously non-commercial zone of the Dnieper-Donets basin, yielding 65 thousand cubic metres per day (2.3 mcf/d) of gas and condensates.

In the Golden Rules Case, production of unconventional gas in Ukraine reaches 3 bcm in 2020, before ramping up to around 20 bcm in 2035. The Golden Rules Case assumes, importantly, that supportive measures are adopted to facilitate investment in the gas sector: Ukraine has a poor investment climate and upstream conventional gas output currently stands at around 20 bcm per year.

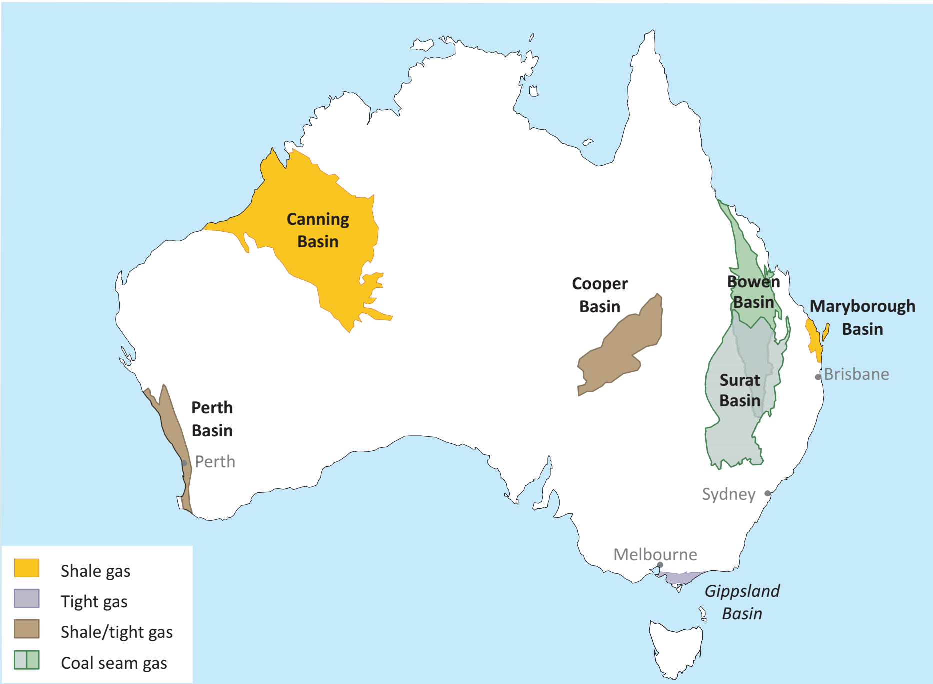
Australia

Resources and production

As a sizeable producer of coalbed methane (known as coal seam gas), Australia is one of only a handful of countries already producing commercial volumes of unconventional gas. Its large resources of shale gas, tight gas and coalbed methane hold the promise of continuing strong growth in unconventional gas output in the long term. The attraction of unconventional gas developments is heightened by the fact that Australia's conventional gas resources, while sizeable, tend to be offshore, expensive to develop and far from national markets.

More is known about the size of the country's coalbed methane resources than about the other two categories of unconventional gas. According to official estimates, demonstrated economically recoverable coalbed methane resources were 930 bcm at the end of 2010 (Geoscience Australia, 2012). The estimates of these resources have grown substantially in recent years, as exploration and development has expanded. Nearly all current reserves are contained in the Surat (69%) and Bowen (23%) basins in central Queensland, with almost all the balance in New South Wales (Figure 3.10).

Figure 3.10 ▷ Major unconventional natural gas resources in Australia



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Commercial production of coalbed methane began in 1996 in eastern Australia and has grown sizeably over the last few years. Output reached 5 bcm in 2010, accounting for about 15% of total Australian gas consumption. Virtually all output comes from the Surat and Bowen basins, with small volumes also now produced from the Sydney Basin. The rapid growth of the unconventional gas industry has been supported by strong demand growth in the eastern Australian market, reflecting in part the Queensland government's energy and climate policies, including a requirement that 13% of power generation in the state be gas-fired by 2005 and 15% by 2010. The abundance of coalbed methane has led to a number of LNG-export projects being proposed in Queensland; and three large plants to be sited at the port of Gladstone are under construction: Queensland Curtis LNG (BG), Gladstone LNG (Santos), and Australia Pacific LNG (Origin and ConocoPhillips), with a fourth – Arrow LNG (Shell/PetroChina) – at an advanced stage of development. Total investment in the three projects underway is projected to be some $40 billion; their capacity of 29 bcm more than doubles current national export capacity. However, policy uncertainty and public reaction to the potential environmental impacts of coalbed methane production has slowed upstream development, particularly in New South Wales.

Remaining recoverable resources of tight gas in Australia are estimated at 8 tcm. The largest resources of these are in low permeability sandstone reservoirs in the Perth, Cooper and Gippsland Basins. Tight gas resources in these established conventional gas-producing basins are located relatively close to existing infrastructure and are currently being considered for commercial exploitation.

Although shale gas exploration is in its infancy in Australia, exploration activity has increased significantly in the last few years. Australia is estimated to contain 11 tcm of remaining recoverable shale gas resources. These are found predominately in the Cooper, Maryborough, Perth and Canning basins. The first vertical wells specifically targeting shale gas were drilled in the Cooper Basin in early 2011 and significant exploration is now underway in this basin and, to a lesser extent, in other promising areas. But a boom in shale gas production is unlikely in the near future because of logistical difficulties and the relatively high cost of labour and hydraulic fracturing.

Regulatory framework

Under the existing regulatory framework governing the upstream hydrocarbons sector in Australia, powers and responsibilities are shared between the federal, state and territory governments and local authorities. The states hold rights over coastal waters from the coast line to the three-mile limit and joint regulatory authority over the federal waters adjacent to each state and the Northern Territory. In addition to various petroleum and pipelines laws, there is an extensive body of legislation governing upstream petroleum activities, covering such aspects as the environment, heritage, development, native title and land rights, and occupational health and safety; most are not specific to the oil and gas sector. A number of bodies across all levels of government have a role in regulating upstream petroleum activities.

Under Australian law, hydrocarbon resources are owned by the state (at federal, state or territory level) on behalf of the community, and governments at all levels have a “stewardship” role in petroleum resource management (AGPC, 2009). Farmers or graziers may hold freehold or leasehold title to land, but generally do not have rights to mineral or petroleum resources – these are subject to petroleum tenure rights granted by the state or territory governments. Underlying native title can coexist with other land title rights. In general, landowners have no right to refuse access to the petroleum tenure holder for petroleum operations; but they do have a claim to compensation for the impact of those operations. Approvals, generally a state or territory responsibility, are required to construct petroleum pipelines and facilities such as LNG trains. Landowners do not have the incentive of ownership of mineral resources to facilitate surface access to unconventional gas projects, but state and territory governments do have an incentive to promote development, as they can benefit from any taxes or royalties levied on production.

Within each jurisdiction, environmental regulation of upstream activities can include hydrocarbon-specific environmental approvals, though there are few rules specific to unconventional gas. The main federal regulations are the Offshore Petroleum and Greenhouse Gas Storage Act 2006 and the Environment Protection and Biodiversity Protection Act 1999 (EPBC Act). Under the EPBC Act, if a project affects matters of national environmental significance, it requires federal approval. LNG projects in Queensland, including their upstream coalbed methane operations, trigger the need for such federal approval. In general, an environmental impact assessment must be carried out in advance of all upstream projects that are likely to have a significant impact on the environment.

The rapid expansion of the coalbed methane industry has led to increased public concern over access issues and the potential environmental risks, particularly the drawdown and contamination of aquifers and groundwater and problems arising from the disposal of produced water. As described in Chapter 1, the techniques used in coalbed methane production differ significantly from those for shale gas; in particular there is a need to remove large amounts of water from the coal formation. This causes concern that those already drawing water from the same formations will be adversely affected and that the disposal of the large water volumes involved in coalbed methane production will not be properly handled. Given the semi-arid conditions in the producing areas, evaporation or discharge of even suitably-treated formation water to existing watercourses may not be appropriate. This has led to delays in issuing approvals for some upstream developments.

The federal government announced in 2011 that all future coalbed methane and other coal projects would come under increased environmental scrutiny. A new, well-resourced and independent scientific committee, established under the EPBC Act, will evaluate most future projects prior to approval to ensure that they do not pose a hazard to underground and surface water sources. Protocols are being developed at federal and state level to determine which projects will be referred to this committee. In Queensland, where most coalbed methane activity is concentrated, new proposals to manage the impact of water extraction on groundwater are being finalised. They provide for cumulative assessment of the impacts on groundwater resources in defined management areas. This work will be based on a major groundwater flow model, designed to predict impacts on aquifers, as well as new monitoring arrangements. A major report, the Surat Underground Water Impact Report, is expected to be published for public consultation by the Queensland Water Commission in mid-2012. A key principle in the regulatory approach is that petroleum operators must make good any impairment of water supply that they cause and that any consequence of underestimating that risk should lie with the operator, not the water source owner or the state government. The upstream industry has argued that the new regulations will hamper the development of the country's nascent unconventional gas sector. In New South Wales, where regulatory activity is less advanced, the state government has introduced a moratorium on hydraulic fracturing while it considers new regulation.

In December 2011, energy and resources ministers at both federal and state levels agreed to develop a nationally harmonised framework for coalbed methane regulation to address the following areas of community concern:

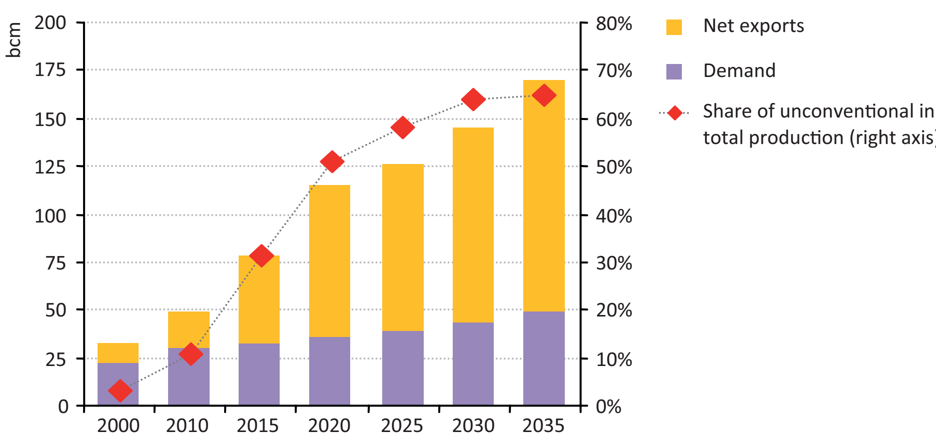
- Water management.
- The need for a multiple land-use framework, meaning measures to reconcile the ability for extraction of coalbed methane with existing and potential agricultural or pastoral uses.
- The application of best practice standards to production activities.
- Minimising environmental and social impacts.

The objective is to achieve measures in these areas which maximise transparency and generate greater public confidence in the effective regulation of the industry while supporting commercial extraction of coalbed methane.

Projections and implications

The prospects for unconventional gas production in Australia hinge to a large degree on whether policy-makers and the industry itself can sustainably manage the associated environmental risks on a basis that retains public confidence in the outcomes. In the Golden Rules Case, this is achieved, with unconventional gas output continuing to expand rapidly, reaching about 60 bcm by 2020 and 110 bcm in 2035. Coalbed methane contributes almost all of this increase, with shale gas production growing more slowly. As a result, total gas production more than triples, with unconventional gas accounting for more than half of gas output after 2020 (Figure 3.11). The projected level of coalbed methane production for 2020 assumes that the four LNG-export projects in Queensland proceed as planned and enter the market before the large increase in unconventional production in other countries, notably China, gains momentum.

Figure 3.11 ▷ Natural gas balance in Australia in the Golden Rules Case*



* The sum of demand and net exports represents total production.

Gas production is driven primarily by exports, based on both conventional and unconventional sources, which rise by 100 bcm in the Golden Rules Case. Exports reach 80 bcm in 2020, based on developments under construction, and continue to grow throughout the projection period. The value of those exports increases seven-fold to just over $55 billion in 2035 (in year-2010 dollars).

In both the Golden Rules and Low Unconventional Cases, east coast Australian domestic prices rise towards the export netback price (the delivered export price less liquefaction and transport costs) from their current very low levels. The high capital costs of Australian LNG plants meaning that these netback levels are likely to be at least $5 to $6/MBtu below the price of LNG delivered to Asian markets. In the Golden Rules Case, Australia's gas consumption nonetheless continues to expand on the back of government policies to encourage switching to gas for environmental reasons (including the recently agreed carbon trading scheme).

In the Low Unconventional Case, coalbed methane production expands at a much slower pace on the assumption of bigger hurdles to development of these resources, while there is no shale gas production at all. In 2035, unconventional gas production falls to around 35 bcm – this is 75 bcm lower than in the Golden Rules Case. The higher international price environment in the Low Unconventional Case means that the upward pull on Australian domestic prices is stronger.

Gas exports still reach more than 110 bcm in the Low Unconventional Case, as investment is shifted to LNG projects based on conventional gas. In this case, the needs of importing countries are much increased and so any gas exporter with the capacity to export has an incentive to do so; this is certainly the case for Australia, with its conventional resources and existing export infrastructure, even if these conventional resources are more costly to develop. Export earnings are even higher in this case, as international gas prices are higher. Unsurprisingly, Australia would stand to benefit from restrictions on unconventional gas developments in other parts of the world, especially in Asia-Pacific, as it is able to expand its own production of conventional and unconventional gas.

Units and conversion factors

This annex provides general information on units and general conversion factors.

Units

Emissions	ppm	parts per million (by volume)
	Gt CO_2-eq	gigatonnes of carbon-dioxide equivalent (using 100-year global warming potentials for different greenhouse gases)
	kg CO_2-eq	kilogrammes of carbon-dioxide equivalent
	gCO_2/kWh	grammes of carbon dioxide per kilowatt-hour
Energy	toe	tonne of oil equivalent
	Mtoe	million tonnes of oil equivalent
	Mt LNG	million tonnes of liquefied natural gas
	MBtu	million British thermal units
	MJ	megajoule (1 joule x 10^6)
	GJ	gigajoule (1 joule x 10^9)
	TJ	terajoule (1 joule x 10^{12})
	kWh	kilowatt-hour
	MWh	megawatt-hour
	GWh	gigawatt-hour
	TWh	terawatt-hour
Gas	mcm	million cubic metres
	bcm	billion cubic metres
	tcm	trillion cubic metres
	mcf	million cubic feet
	bcf	billion cubic feet
	tcf	trillion cubic feet
Mass	kg	kilogramme (1 000 kg = 1 tonne)
	kt	kilotonnes (1 tonne x 10^3)
	Mt	million tonnes (1 tonne x 10^6)
	Gt	gigatonnes (1 tonne x 10^9)

Monetary	$ million	1 US dollar x 10^6
	$ billion	1 US dollar x 10^9
	$ trillion	1 US dollar x 10^{12}
Oil	b/d	barrels per day
	kb/d	thousand barrels per day
	mb/d	million barrels per day
Power	W	watt (1 joule per second)
	kW	kilowatt (1 watt x 10^3)
	MW	megawatt (1 watt x 10^6)
	GW	gigawatt (1 watt x 10^9)
	TW	terawatt (1 watt x 10^{12})

General conversion factors for energy

Convert to:	bcm	bcf	Mt LNG	TJ	GWh	MBtu	Mtoe
From:	multiply by:						
bcm	1	35.315	0.7350	4.000 x 10^4	11.11 x 10^3	3.79 x 10^7	0.9554
bcf	2.832 x 10^{-2}	1	2.082 x 10^{-2}	1.133 x 10^3	3.146 x 10^2	1.074 x 10^6	2.705 x 10^{-2}
Mt LNG	1.360	48.03	1	54 400	15 110	5.16 x 10^7	1.299
TJ	2.5 x 10^{-5}	8.829 x 10^{-4}	1.838 x 10^{-5}	1	0.2778	947.8	2.388 x 10^{-5}
GWh	9.0 x 10^{-5}	3.178 x 10^{-3}	6.615 x 10^{-5}	3.6	1	3 412	8.6 x 10^{-5}
MBtu	2.638 x 10^{-8}	9.315 x 10^{-7}	1.939 x 10^{-8}	1.0551 x10^{-3}	2.931 x 10^{-4}	1	2.52 x 10^{-8}
Mtoe	1.047	36.97	0.7693	4.1868 x 10^4	11 630	3.968 x 10^7	1

Notes

- Gas volumes are measured at a temperature of 15°C and a pressure of 101.325 kilopascals.
- The Gross Calorific Value (GCV) of gas is defined as 40.0 MJ/cm for conversion purposes in the table above.
- The global average GCV varies with the mix of production over time, in 2009 it was 38.4 MJ/cm.
- 1 Mtoe is equivalent to 10^7 gigacalories.

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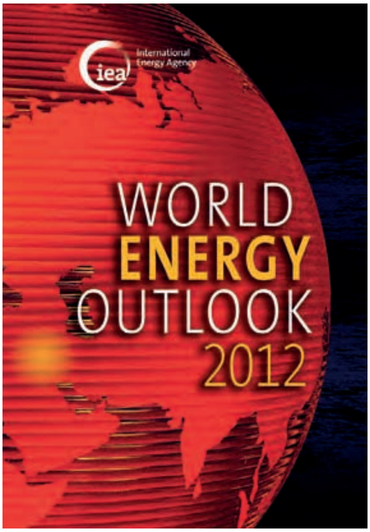

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The Joint Institute for Strategic Energy Analysis is operated by the Alliance for Sustainable Energy, LLC, on behalf of the U.S. Department of Energy's National Renewable Energy Laboratory, the University of Colorado-Boulder, the Colorado School of Mines, the Colorado State University, the Massachusetts Institute of Technology, and Stanford University.

Technical Report
NREL/TP-6A50-55538
November 2012

Contract No. DE-AC36-08GO28308

JISEA
Joint Institute for
Strategic Energy Analysis

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About JISEA

The Joint Institute for Strategic Energy Analysis (JISEA) conducts interdisciplinary research—realized through teams drawn from the founding partners and a network of national and global affiliates—and provides objective and credible data, tools, and analysis to guide global energy investment and policy decisions. JISEA is focused on providing leading analysis; guiding decisions on energy, investment, and policy; and answering questions that enable a cost-effective transition to sustainable energy at significant speed and scale, while minimizing unintended impacts.

JISEA is operated by the Alliance for Sustainable Energy, LLC, on behalf of the U.S. Department of Energy's National Renewable Energy Laboratory (NREL), the University of Colorado-Boulder, the Colorado School of Mines, the Colorado State University, the Massachusetts Institute of Technology, and Stanford University. Each institution brings a unique set of capabilities to the partnership.

Learn more at JISEA.org.

Foreword

We are very pleased to present this work on natural gas and the transformation of the United States' power sector. The subject is both highly topical and divisive. Very few people saw the dramatic changes coming that are being witnessed in the U.S. natural gas sector. The critical role of unconventional gas—and specifically, shale gas—has been dramatic. The changes taking place in the U.S. natural gas sector go well beyond the boundaries of traditional energy-sector analysis. They touch on areas as diverse as foreign policy and industrial competitiveness.

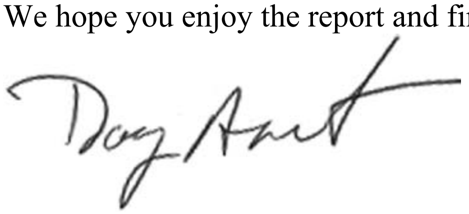
This makes the topic ripe for robust analytical work, which is the role of the Joint Institute for Strategic Energy Analysis (JISEA).

To help inform both the national and international dialogue on this subject, we have focused on a few key areas critical to decision makers. These issues include greenhouse gas emissions, regulatory interventions, water management, and the portfolio of generation in the power sector.

As part of our series of studies on the U.S. energy system, this body of work continues to elucidate details related to life cycle greenhouse gas emissions of shale gas relative to other options for power generation. It also contributes new analysis related to water and regulatory frameworks that are evolving apace. Additionally, we evaluate various pathways for the evolution of the electric sector given a range of options for natural gas, other technologies, and policy.

Although the four principal areas of focus in this report are closely interrelated, each has its own specific needs in terms of analysis, investment risk, and policy design. We have presented detailed consideration of each area, with further appended supporting material, to contribute to the ongoing and increasing national and international dialogue.

We hope you enjoy the report and find the results and discussion useful for your work.



Douglas J. Arent
Executive Director, JISEA

Preface

This report was developed with guidance from a cross-section of natural gas and electricity sector stakeholders. In 2011, JISEA convened a workshop with representatives from these organizations, some of whom also provided financial support for this work. That workshop resulted in identifying several key analytical issues for natural gas in the electric power sector that need to be addressed. Research, analysis, and writing were performed independently by the authors, with editorial oversight by JISEA. This study has been extensively peer reviewed. Findings, content, and conclusions of this study are the sole responsibility of the JISEA study team. JISEA provides objective information so that decision makers can make informed choices, but does not make its own policy recommendations.

Although the sponsoring organizations provided invaluable perspective and advice to the study group, individual members may have different views on one or more matters addressed in the report. The sponsoring organizations were not asked individually or collectively to endorse the report findings nor should any implied endorsement by the sponsoring organizations be assumed.

Authors

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The authors would like to thank the following individuals for research assistance: Ashwin Dhanasekar, Shane White, and Xiaochen Yang of Colorado State University; Katie Patterson and Jamie Cavanaugh of the University of Colorado Law School; and Carolyn Davidson, Andrew Martinez, Patrick O'Donoughue, and Vanessa Pineda of the National Renewable Energy Laboratory.

We would like to thank the following organizations for their support and steering committee engagement: British Petroleum; Colorado Oil and Gas Association; ConocoPhillips; DB Climate Change Advisors; Electric Power Research Institute; GE Energy; National Grid; Southern Company; UBS Global Asset Management; and Xcel Energy.

This report has been reviewed in draft form by individuals chosen for their diverse perspectives and technical expertise. These reviews serve to make this report as technically sound as possible, and they ensure that the report meets institutional standards for objectivity, evidence, and responsiveness to the study scope.

We wish to thank the following individuals for their participation in the review of this report:

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Acronyms and Abbreviations

AGR	acid gas removal
bbl	barrels
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
BLM	Bureau of Land Management
Btu	British thermal unit(s)
CBM	coal-bed methane
CCS	carbon capture and sequestration
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CES	clean energy standard (also known as clean electricity standard)
cf	cubic feet
CH_4	methane, the primary component of natural gas
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
COGCC	Colorado Oil and Gas Conservation Commission
CSP	concentrating solar power
CWTs	centralized waste treatment facilities
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EUR	estimated ultimate recovery
FF	frac flowback (water)
g	gram(s)
GHG	greenhouse gas
GIS	geographic information system
GW	gigawatt(s)
hp	horsepower
hr	hour
kg	kilogram(s)
kWh	kilowatt-hour(s)
lb	pound(s)
LCA	life cycle assessment
LNG	liquefied natural gas
MJ	megajoules
Mcf	thousand cubic feet
MMBtu	million British thermal unit(s)
NG-CC	natural gas combined-cycle
NG-CCS	natural gas generator with carbon capture and sequestration
NG-CT	natural gas combustion turbine
NGLs	natural gas liquids
NO_x	nitrogen oxides
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standards
POTWs	publicly owned treatment works
PW	produced water
PV	photovoltaic

RE	renewable energy (also known as renewable electricity)
RE Futures	Renewable Electricity Futures Study
ReEDS	Regional Energy Deployment System
SCC	Source Classification Code
scf	standard cubic foot
SEAB	Secretary of Energy Advisory Board Shale Gas Production
SolarDS	Solar Deployment System
TCEQ	Texas Commission on Environmental Quality
Tcf	trillion cubic feet
Tg	teragram(s), or million metric ton(s)
VOC	volatile organic compound
yr	year

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Executive Summary

Domestic natural gas production was largely stagnant from the mid-1970s until about 2005. Planning had been under way by the early 2000s to construct about 40 liquefied natural gas import terminals along the U.S. coasts to meet anticipated rising demand. However, beginning in the late 1990s, advances linking horizontal drilling techniques with hydraulic fracturing allowed drilling to proceed in shale and other formations at much lower cost. The result was a slow, steady increase in unconventional gas production.

As the technology improved and spread, domestic shale gas output began to increase rapidly, such that by 2008 commentators began to routinely speak of a shale gas "boom." Today, shale gas accounts for about 30% of total U.S. natural gas production—up from only 4% in 2005—helping to make the United States the largest producer of natural gas in the world by 2009. Within a decade, the question of how much more dependent the country would become on natural gas imports had been replaced by how much the U.S. gas supply will affect the economics and geopolitics of energy around the globe.

Although the long-term outcome of the shale gas revolution is far from decided, significant shifts are already apparent in U.S. power markets. In that context, low-price natural gas has had the greatest impact to date on generation by coal power plants. Since 2008, coal's share of annual generation has declined from 48% to 36% as of August 2012. This switch from coal to natural gas, combined with growth of renewable energy generation, has led to a reduction of carbon dioxide emissions in the U.S. power sector of about 300 million tons—equivalent to 13% of total power sector emissions in 2008.

It remains unclear, however, whether natural gas will continue to exert such a dramatic impact on the power sector and the overall U.S. economy. If natural gas prices continue to stay at, or near, historically low levels, then a self-correction in the shale gas boom may occur. Due to price concerns, some companies have shifted away from drilling for dry gas and instead are focusing on plays that provide natural gas liquids. The ongoing debate is about what price is needed for unconventional natural gas production to be more sustainable over the medium term. As an example, analysis from Range Resources indicates that New York Mercantile Exchange prices of $4–$6/MMBtu are needed at the vast majority of plays to generate adequate returns on investment.[1] Other factors—including "use it or lose it" lease terms, reserve filings with the Securities and Exchange Commission, and the amount of natural gas liquids that can be recovered—all play a role in continuing investment decisions. But, for now, natural gas markets are still widely acknowledged as oversupplied, and storage facilities held record high amounts of gas as of mid-2012.

Hydraulic fracturing has received negative attention in many parts of the country—especially those areas not accustomed to the oil and gas industry—due to real and perceived environmental and social concerns. Water use and contamination, air pollution, greenhouse gas (GHG) emissions, and truck traffic are among the concerns that have strained the social license to operate, and they have been the subject of multiple national and international reports and

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[1] Specifically, a 12% internal rate of return (IRR). The reference to this analysis appears in Ventura, J., 2012. "Uncovering Tomorrow's Energy Today," presentation at the Goldman Sachs Global Energy Conference 2012. 10 January 2012. Slide 11. Accessed 9 June 2012.

continued dialogue. Field practices associated with unconventional natural gas production have evolved rapidly in some regions, either from new regulatory requirements or voluntary company practices. These field practices are still evolving, can be uneven across regions, and are sometimes controversial. At the same time, consolidation within the industry is shifting production from smaller to larger companies.

The Joint Institute for Strategic Energy Analysis (JISEA) designed this study to address four related key questions, which are a subset from the wider dialogue on natural gas:

1. What are the life cycle greenhouse gas (GHG) emissions associated with shale gas compared to conventional natural gas and other fuels used to generate electricity?
2. What are the existing legal and regulatory frameworks governing unconventional gas development at federal, state, and local levels, and how are they changing in response to the rapid industry growth and public concerns?
3. How are natural gas production companies changing their water-related practices?
4. How might demand for natural gas in the electric sector respond to a variety of policy and technology developments over the next 20 to 40 years?

Major Findings

Although the questions analyzed in this report are interlinked to a certain extent, they have specific requirements in terms of analysis methodologies and associated stakeholders. The key findings are presented very briefly as follows:

- **Greenhouse gas emissions:** Based on analysis of more than 16,000 sources of air-pollutant emissions reported in a state inventory of upstream and midstream natural gas industry, life cycle greenhouse gas emissions associated with electricity generated from Barnett Shale gas extracted in 2009 were found to be very similar to conventional natural gas and less than half those of coal-fired electricity generation.

- **Regulatory trends:** The legal and regulatory frameworks governing shale gas development are changing in response to public concerns and rapid industry changes, particularly in areas that have limited experience with oil and gas development. All of the states examined in this study have updated their regulatory frameworks to address the opportunities and challenges associated with increasing unconventional natural gas production.

- **Water management:** Many regions evaluated in this study are making greater use of innovative water management practices to limit real and perceived risks. However, a lack of reliable, publicly available water usage and management data—such as total water withdrawals, total wells drilled, water-recycling techniques, and wastewater management practices—currently hinders efforts to develop appropriately flexible and adaptive best management practices. Recent studies have documented a number of management practices related to the chemical makeup of fracking fluids, impacts on local freshwater, and on-site wastewater management that may be appropriate in many locations.

However, to date, no public studies have been published on cost-benefit, risk-mitigation potential, or the transferability of practices from one shale play to another.

- **Electric power futures:** A number of different future electric power scenarios were analyzed to evaluate both the implications of shale gas development and use, and various policy and technology changes. These scenarios include power plant retirements, advances in generation technologies, federal policies to reduce greenhouse gas emissions, and variations in natural gas supply and demand. We find that natural gas use for power generation grows strongly in most scenarios.

Life Cycle Greenhouse Gas Emissions from Barnett Shale Gas Using Air-Quality Inventory Data

A national debate over life cycle GHG emissions[2] from shale natural gas erupted in 2011 after a study was released stating that shale gas had equivalent or even greater GHG emissions than coal.[3] Since then, a number of other published, peer-reviewed studies have included contrary findings,[4] although data limitations and methodological variability make conclusive statements problematic about the "real" GHG emission profile.

For Chapter 1, the study team conducted original research on life cycle GHG emissions associated with natural gas production in the Barnett Shale play in Texas. This estimate leverages high-resolution empirical data to a greater extent than previous assessments. The data sources and approach used in this study differ significantly from previous efforts, providing an estimate valuable for its complementary methodological approach to the literature.

The authors used inventories from 2009 that tracked emissions of regulated air pollutants by the natural gas industry in the Barnett Shale play. The Texas Commission on Environmental Quality (TCEQ) collected and screened these inventories. These data cover the characteristics and volatile organic compound (VOC) emissions of more than 16,000 individual sources in shale gas production and processing. Translating estimated emissions of VOCs into estimates of methane and carbon dioxide emissions was accomplished through the novel compilation of spatially heterogeneous gas composition analyses.

Major findings from this analysis of life cycle GHG emissions include:

- Electricity generated using a modern natural gas combined-cycle turbine combusting Barnett Shale gas produced and processed in 2009 has life cycle GHG emissions ranging between 420 and 510 grams carbon dioxide-equivalent emissions per kilowatt-hour (g

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[2] GHG emissions considered within a life cycle assessment (LCA) include those from the "fuel cycle" of natural gas, which includes activities from well drilling and completion, through production, processing, and transport to the power plant, as well as from the life cycle of the power plant, which includes construction and decommissioning of the power plant and combustion of the fuel. Results are normalized per unit of electricity generated (kWh). See Figure 7 within Chapter 1 and the surrounding text for further description of the scope of this LCA.
[3] Howarth, R. W., R. Santoro, and A. Ingraffea. 2011. "Methane and the greenhouse gas footprint of natural gas from shale formations." *Climatic Change Letters*, DOI: 10.1007/s10584-011-0061-5 (http://www.springerlink.com/content/e384226wr4160653/fulltext.pdf).
[4] These studies include Burnham et al. 2012; Jiang et al. 2011; Skone et al. 2011; Stephenson et al. 2011; Hultman et al. 2011.

CO_2e/kWh) generated, depending on assumed lifetime production of a well, with a central estimate of about 440 g CO_2e/kWh—similar to levels reported in the literature from conventional natural gas and less than half that typical for coal-fired electricity generation (Figure 1).[5] Comparisons to conventional natural gas and coal are achieved through harmonization of 200 published estimates of life cycle GHG emissions for those two technologies.[6] Harmonization is a meta-analytical process that makes consistent the assumptions and methods between LCAs.

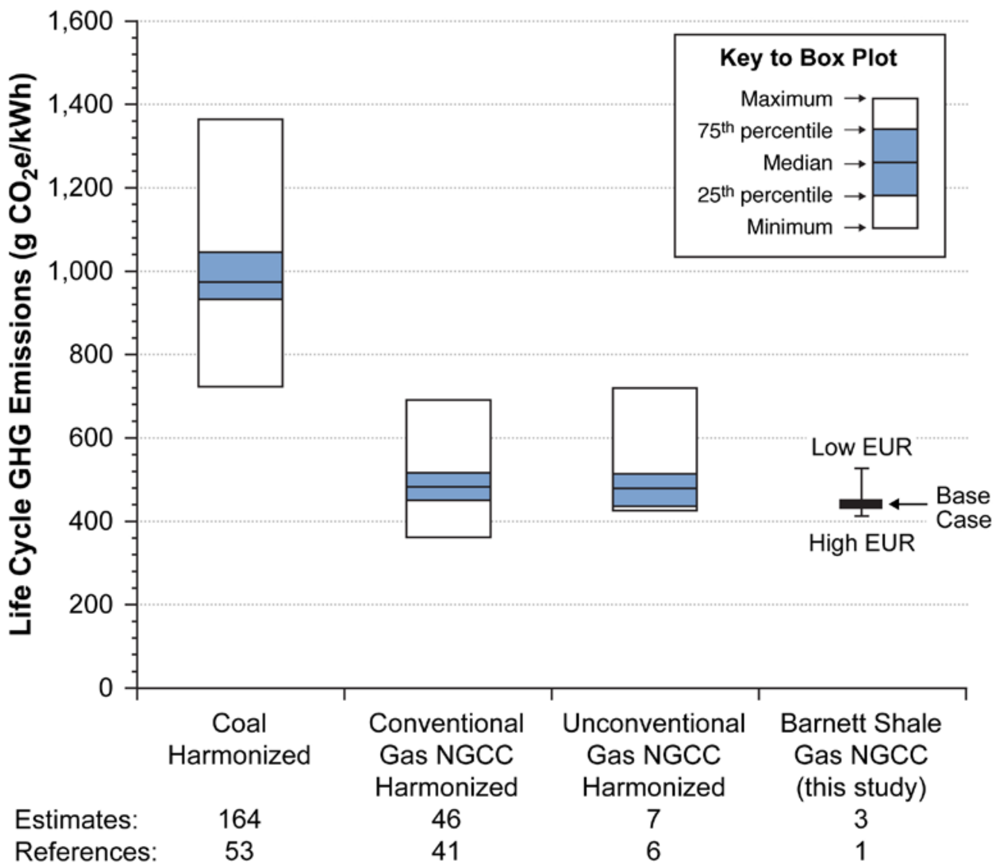

Figure 1. Estimate of life cycle GHG emissions from 2009 Barnett Shale gas combusted to generate electricity in a modern natural gas combined-cycle (NGCC) turbine compared to previously published estimates for unconventional (mostly shale) gas, conventional natural gas, and coal after methodological harmonization.

Notes: EUR = estimated ultimate recovery, or lifetime production; NGCC = natural gas combined-cycle turbine

[5] The results reported here do not include emissions associated with liquids unloading, a process that the natural gas industry recently reported as applicable to both conventional *and* unconventional wells, but without direct evidence for the Barnett Shale play. (See: Shires and Lev-On (2012).)
However, inclusion of these emissions would not qualitatively change our findings.

[6] See Whitaker et al. 2011 and O'Donoughue et al. 2012 for systematic review and harmonization of published estimates of life cycle GHG emissions from coal-fired and conventional natural gas-fired electricity generation, respectively.

- An estimated 7% to 15% of life cycle GHG emissions from electricity generation (mean = 9%) are from methane emissions throughout the fuel cycle of Barnett Shale gas (well pre-production activities through transmission), mostly from venting during completion and workover, and from the natural gas transmission pipeline network.
- GHG emissions result from many sources throughout the production and use of natural gas. Based on our analysis, more than half can be characterized as sources with potentially controllable leakage—for instance, from tanks or vents**.** Another 20% are combustion sources, which also have some emission control opportunities. Remaining sources, called fugitive emissions, are more challenging to control because of their dispersed nature.
- An estimated 1.5% of Barnett Shale produced gas is emitted to the atmosphere before reaching the power plant, much of which is potentially preventable, with an additional 5.6% of produced gas consumed along the process chain as fuel for different types of engines. Based on the estimated methane content of this produced gas and average assumed lifetime production of a well, this equates to a central estimate of leakage rate across the life cycle of 1.3% methane volume per volume of natural gas processed.
- Chemical composition of produced gas varies considerably within the Barnett Shale area such that at the county level, estimates of GHG emissions differ significantly from those based on composition averaged at a higher spatial resolution (play or nation). Variability in gas composition has implications for the understanding of emission sources and the design of regulatory emission control strategies.

A Changing Regulatory Framework for Unconventional Gas Production

Chapter 2 examines the main federal, state, and local regulatory frameworks that govern unconventional natural gas development. Specifically, it focuses on requirements related to water withdrawals used for hydraulic fracturing, disclosure of chemicals used in hydraulic fracturing fluids, setbacks for wells, baseline water monitoring of surface water resources or water wells, well-construction standards, "green" or "reduced emission" completions, storage of waste in closed-loop systems, and the disposal of produced water. It also examines state compliance monitoring and enforcement capabilities, and the efforts by some local governments in key gas-producing states to limit—and, in some cases, ban—unconventional gas development. Major findings include the following:

- There is a trend toward more regulation at all levels of governance, but there has been a corresponding increase in regulatory fragmentation and differentiation at state and local levels. Better coordination and policy alignment among regulators can help to reduce risks to industry and the public of regulatory fragmentation—including uncertainty, delays, gaps, and redundancies across jurisdictions. Improved communication and sharing of information among regulators at all levels of government and across jurisdictions, as well as increased transparency in the form of publicly available data from industry, would help address regulatory fragmentation and inform regulatory development tailored to specific geographic and geologic characteristics.

- Compliance monitoring and enforcement varies across states, with significant implications for the efficacy of regulations, as well as public confidence. Increased public disclosure of voluntary information—as well as public disclosure of violations, enforcement actions, and company compliance—would increase transparency, offer opportunities to highlight the compliance records of leading companies who have demonstrated a commitment to safe natural gas production, and help address public concerns.

- There is a significant range in the environmental performance of operators in the industry, with some operators performing at a level that goes beyond existing regulations and other operators falling short. There is an evolving portfolio of recommended practices emerging from across the stakeholder community; these practices can complement and supplement regulations.
- The varied state and local approaches to regulation can provide important opportunities for learning and innovation regarding substantive rules, the role of best practices, and compliance and enforcement. Regulators might consider adopting performance-based standards, rather than freezing today's "best management practices" into prescriptive rules that could become outdated.

Management Practices in Shale Gas Production: Focus on Water

Chapter 3 addresses current water usage and water management practices at shale gas development sites and discusses risks to water availability and quality. We evaluated publicly available water usage data from six shale plays throughout the United States. When data were available, we conducted statistical analyses from a randomized sample of wells in each play to gauge current estimates of water usage per well. In addition, data were collected on current wastewater management techniques and volumes associated with managing produced water from wells along with the returned fracking fluids. Lastly, in addition to analyzing current industry practices, we evaluated how water usage, well number, and water management techniques have evolved over time, indicating that water risk and management issues in the future may differ from historical issues. Natural gas exploration and production has significant spatial variability in community and environmental issues, current practices, and regulations. Therefore, JISEA is also publishing the water-related results of this study in a web-based GIS format.

The three primary water impact risks are: regional resource depletion due to use of fresh water during hydraulic fracturing, surface water degradation, and groundwater degradation. Impact risks to water resources vary geographically based on three considerations: 1) where the water comes from, 2) what water use and management practices are followed on site for hydraulic fracturing, and 3) how and where produced water and frac flowback water are treated and/or disposed.

Major findings from this analysis of water impacts include the following:

- Risks to regional freshwater depletion depend on a variety of factors, including water use per well, total number of wells, water recycling rates, and regional water availability. Analysis of use data for four of the six regions from 2007 to 2011 indicated average water use per well ranges from 1.1 to 4.8 million gallons, with a multi-region average of 3.3 million gallons. The total magnitude of water usage depends on the number of wells drilled, which has increased in most regions from 2007 to 2011. In the Eagle Ford play, for example, gas wells increased from 67 in 2009 to 550 in 2011. Total freshwater usage depends on water recycling rates, which may vary greatly depending on location. In

2011, the highest rates of recycling were reported in Pennsylvania, where 37% of produced water and 55% of frac flowback water were recycled, representing nearly 200,000 gallons per well, or 4% of average water use per well in Pennsylvania. Total impacts on regional freshwater resources can be evaluated by comparing total freshwater uses with estimates of regional freshwater availability.

- Wastewater management practices vary regionally and show different trends from 2008 to 2011. In Pennsylvania, 80% of produced water and 54% of frac flowback water was treated through surface water discharge in 2008, whereas in 2011, less than 1% of produced water and frac flowback was treated through surface water discharge. In 2011, centralized disposal facilities and recycling are the primary wastewater management methods, accounting for 80% of produced water volumes and 99% of frac flowback volumes. In Colorado, surface water discharge of both produced water and frac flowback volumes has increased from 2% in 2008 to 11% in 2011. Management of produced water and frac flowback through onsite injection pits and evaporation ponds have remained the dominant practices from 2008 to 2011, representing 72% and 58%, respectively. Treatment at a centralized disposal facility has increased from 26% to 31% from 2008 to 2011. The management and transport of produced water and frac flowback water is considered to be the stage at which spills and leaks are most likely.
- A lack of reliable, publicly available water usage and management data hinders comprehensive analyses of water risks**.** Data are not publicly available for total water withdrawals, total gas wells drilled, flowback volume per well, water recycling techniques, wastewater management, and other management practices for many regions. These data would assist in developing appropriately flexible and adaptive best management practices. Certain resources—such as the State Review of Oil and Natural Gas Environmental Regulations (STRONGER) and FracFocus—have greatly increased public access to information about risks of hydraulic fracturing; however, further efforts would be beneficial.
- A variety of best management practices are currently being employed in different regions, but there is industry uncertainty over transferability, cost-effectiveness, and risk mitigation potential. Recent studies have documented a number of water-related management practices related to the chemical makeup of fracking fluids (disclosure of additives, minimizing or switching to more benign additives, baseline water quality testing), the impacts on local freshwater (measuring and reporting of volumes, water recycling, use of non-potable or non-water sources), and onsite wastewater management techniques (use of closed-loop drilling systems, elimination of flowback and freshwater mixing in open impoundments, use of protective liners at pad sites) that may be appropriate in many locations. However, to date, there are no publicly available studies that have performed cost-benefit analyses, evaluated the risk-mitigation potential of each strategy, or analyzed practices that could be transferred from one shale play to another.

Modeling U.S. Electric Power Futures Given Shale Gas Dynamics

In Chapter 4, the study evaluates different electric power scenarios that are influenced by natural gas availability and price, as well as other key policy, regulatory, and technology factors. Many of the scenarios examine sensitivities for the estimated ultimate recovery (EUR) of gas fields. High-EUR corresponds to more abundant and inexpensive natural gas compared to Low-EUR.

Major findings from the electric sector analysis include the following:

- Natural gas demand by the power sector would grow rapidly—more than doubling from the 2010 level by 2050—in the Reference, or baseline, scenario.[7] Figure 2 illustrates the range of natural gas power generation in all scenarios. The main Reference scenario suggests that natural gas would replace coal as the predominant fuel for electricity generation. Attributes of this baseline scenario include rising power demand, stable greenhouse gas emissions, and slowly rising electricity prices that reflect natural gas availability and prices. By 2050, in the Reference scenario, gas could represent from 28% to 38% of power-sector generation compared to the 2010 portion of 20%.
- In a coal retirement scenario, natural gas, and wind to a lesser extent, replaces coal-based generation. Our modeling results indicate no impact on power sector reliability from 80 GW of coal retirements by 2025 on an aggregate scale, although additional detailed dispatch modeling is needed to evaluate localized impacts. National average retail electricity prices in the retirement scenario increase by less than 2% in 2030 compared to the baseline.
- Under a clean energy standard (CES) scenario, U.S. power sector carbon dioxide emissions would decrease by 90% between 2010 and 2050, with a corresponding 6%–12% increase in average retail electricity prices, including transmission build-out that ranges from 3 to 6 times more than the Reference scenario (measured in million MW-miles). Among the CES sensitivity scenarios, large quantities of variable renewable energy and flexible gas generation work synergistically to maintain system reliability requirements.

[7] A Reference scenario serves as a point of comparison with other alternative scenarios. The Reference assumes a fairly static view of the future, so it, and all alternative scenarios, should not be considered forecasts or predictions of the future.

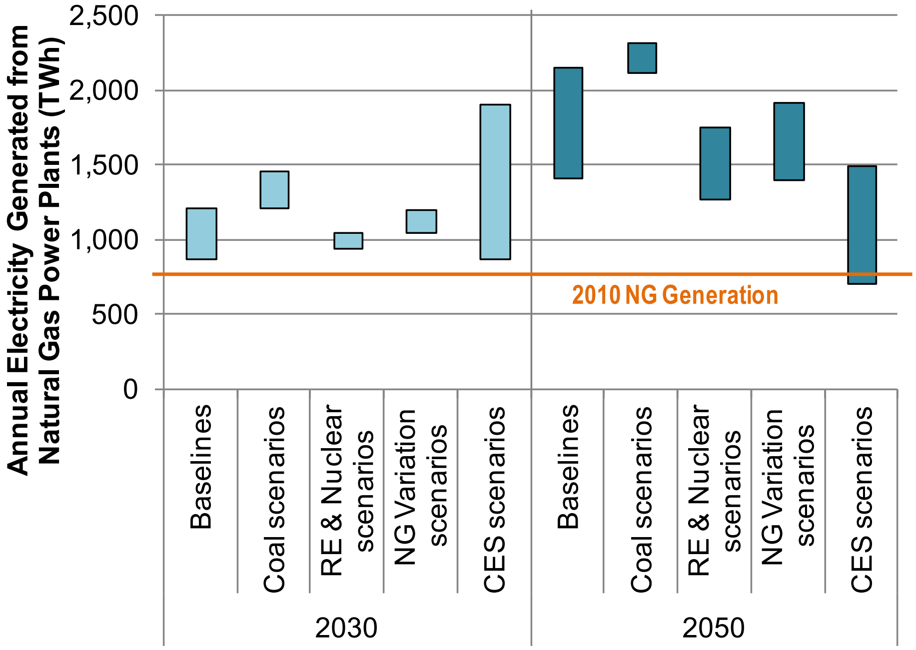

Figure 2. Range of electricity generated from natural gas plants in the scenario analysis

- Advances in generation technologies can have a significant impact on estimated carbon emissions, electricity diversity, and prices. For example, nuclear capital costs would need to decline by half, while gas prices remain relatively high (as simulated in the low-EUR assumption), for the nuclear generating option to compete economically with other options. Wind and solar electricity could more than double by 2050 compared to the Reference scenario with continued improvements in the cost and performance of these technologies. Likewise, continued improvements in production techniques for unconventional natural gas production could enable natural gas to continue to grow market share.
- We consider a range of potential incremental costs associated with operating practices that could better address some of the public concerns in the production of unconventional natural gas. Some of these options include recycling larger amounts of frac flowback water, reducing methane releases to the atmosphere, setting well locations further from potentially sensitive communities, and assuring consistent use of best practices or regulations in well drilling and completions. Sensitivities in incremental costs were evaluated from \$0.50/MMBtu to \$2/MMBtu. For example, additional costs of \$1/MMBtu associated with some or all of these several dozen operating practices would lead to a 17% reduction in gas use for power generation by 2050 compared to the Reference scenario; however, gas-fired generation still more than doubles from the 2010 level.
- A “dash-to-gas” scenario, where other sectors of the economy increase natural gas demand by 12 billion cubic feet per day by 2030, would likely result in higher domestic gas prices and lead to a roughly 20% reduction in power sector natural gas use by 2050 compared to the Reference scenario in that year, but still nearly twice the level used in 2010. Additional research is needed to understand how natural gas prices respond to rising demand in the new natural gas environment.

The rapid expansion of shale gas has created dynamic opportunities and challenges in the U.S. energy sector. How long the ascendancy of natural gas in the electric sector will last will be a function of a wide variety of market and policy factors. The story of unconventional gas is evolving rapidly, and in some cases, unexpectedly. Robust and up-to-date analysis will remain critical to informing the key decisions that must be made by all types of stakeholders in the energy and environmental arenas.

Introduction

This report addresses several aspects of the changing context of natural gas in the U.S. electric power sector. Increasingly plentiful and affordable natural gas has catalyzed major changes in U.S. power generation and has helped to boost U.S. economic recovery. Increased substitution of natural gas for coal in power generation has also cut U.S. GHG emissions. However, processes to produce natural gas—shale gas in particular—have also elevated environmental and safety concerns in certain regions of the country. The rapid rise of natural gas is also beginning to drive more thought on longer-term energy policy issues such as the appropriate level of generation diversity (given the history of volatile prices for natural gas), and trajectories of natural gas use that will still allow GHG mitigation sufficient to address the climate challenge.

This report is intended to help inform those energy policy and investment discussions. This chapter first outlines the current dynamics of natural gas in the power sector and then describes how the remainder of the report addresses selected challenges and opportunities in the use of natural gas to generate electricity.

Natural gas supply and demand are transforming the energy marketplace. Natural gas prices have been relatively volatile over the past 40 years, at least compared to coal (see Figure 3). Today, advances in unconventional gas production, which include a host of technologies and processes beyond horizontal drilling and hydraulic fracturing,[8] have enabled a new market outlook. Shale production grew from less than 3 billion cubic feet per day (bcf/d) in 2006 to about 20 bcf/d by mid-2012.[9] Without this expansion, natural gas prices might be significantly higher because most other sources of domestic natural gas production are in decline.

Given the low-price outlook, many new potential uses for natural gas outside of power generation are being considered and developed—including the export of LNG, the use of compressed natural gas in vehicles, the construction of ethylene plants and other chemical facilities that use natural gas and associated products as a feedstock, and, potentially, investment in gas-to-liquids facilities that convert natural gas into synthetic petroleum products (i.e., diesel) that can be used as a transportation fuel in existing infrastructure. Efforts to further develop the latter may become particularly strong if the price gap shown in Figure 3 remains.

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[8] For a description of this technological progress, see Seto (2011).
[9] In 2011, the U.S. power sector consumed about 22 bcf/d and the entire economy consumed about 67 bcf/d (EIA 2012b).

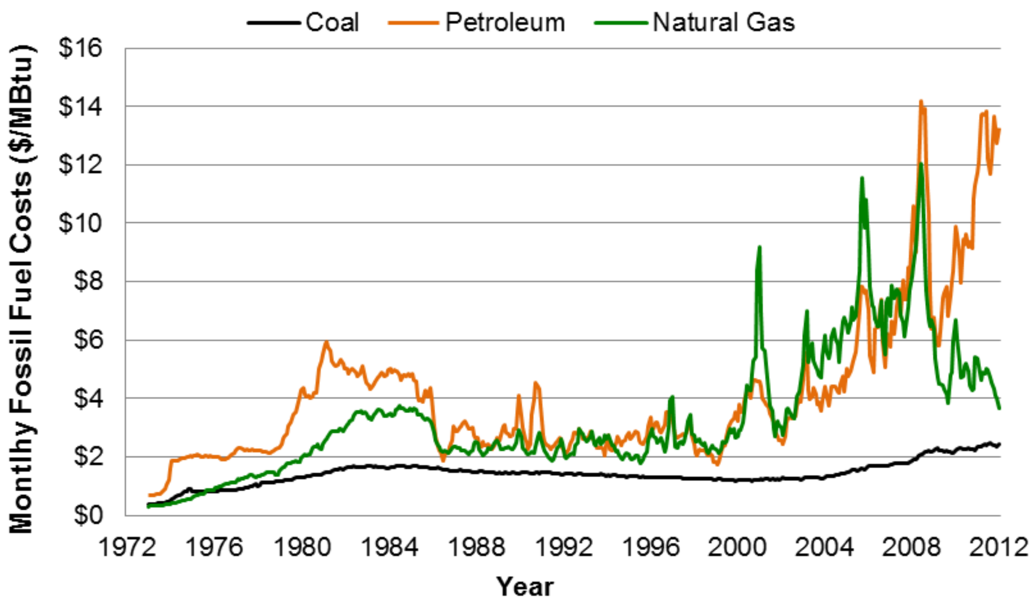

Figure 3. Volatility in fossil fuel costs for power generators

Source: EIA, "Monthly Energy Review," April 27, 2012.

However, given the current low-price environment, many producers have scaled back their plans to drill for dry natural gas, even as they accelerate drilling for wet natural gas (whose natural gas liquids are sold at prices comparable to petroleum products). These cutbacks have contributed to the recent increase in Henry Hub prices, from a low of $1.90/MMBtu in early 2012 to more than $3.60/MMBtu by November 2012. On the other hand, the number of rigs actively developing natural gas has declined sharply since 2009 while production continues to expand, indicating that producers are getting more output with less input (Ebinger et al. 2012). Where prices go next will be influenced by potential new sources of demand noted above, and by supply-side issues, including continued technology improvement, efforts to better protect the environment, and regulatory requirements.

Coal-generated electricity is rapidly declining. Dramatic changes are occurring in the U.S. electric power sector. These changes include a steep reduction in the portion of electric power coming from coal combustion, and a corresponding increase in that provided by natural gas and (to a lesser extent) renewable sources, especially wind power (see Figure 4). Eastern and southern regions are generally experiencing the most rapid shift in generation mix (see Appendix A for more detail). Coal's contribution to total annual U.S. power generation has fallen more rapidly over the past four years than in any time in the history of data collection—from roughly 48% of U.S. generation in 2008 to 36% as of August 2012. Had coal generation remained at the 2008 level, the U.S. power sector would be emitting roughly 300 million tons of additional CO_2 each year.[10]

[10] This is a "burner tip" analysis only and does not consider the full life cycle GHG emissions of coal or natural gas. Data for 2012 are based on a rolling 12-month sum ending in August. The carbon mitigation calculation is based on a 440 TWh reduction in coal generation and corresponding increase in natural gas combined-cycle generation of 310 TWh. Growth in certain renewable generation sources and a reduction in power demand make up the remaining

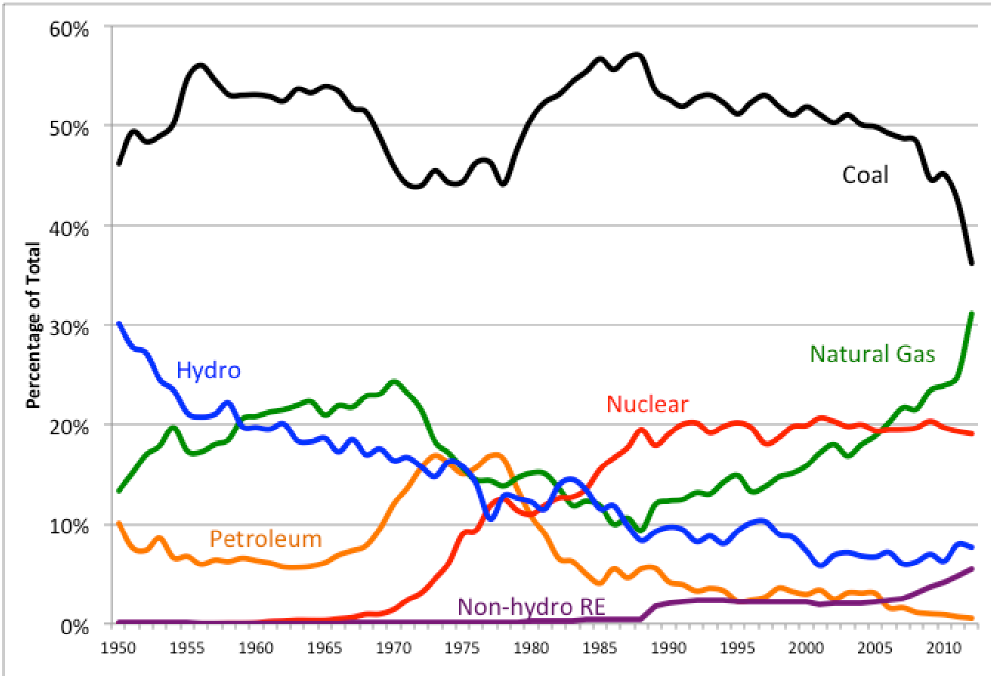

Figure 4. Coal-fired electricity generation is declining rapidly as the use of natural gas and renewable energy expand

Source: EIA, "Annual Energy Review," September 27, 2012; EIA "Electric Power Monthly," October 31, 2012. Data for 2012 includes generation through August only.

The primary drivers of these changes include low-priced natural gas resulting from rapidly growing shale gas production, an unusually warm 2011–2012 winter throughout much of the contiguous United States,[11] and the expectation that EPA will issue new or revised power plant regulations to further protect the environment.[12] It remains to be seen whether this trend of declining coal generation continues, stabilizes, or reverses itself.[13]

Hydraulic fracturing presents opportunities and challenges that are in the headlines daily. These opportunities include additional U.S. jobs, increased economic activity, potentially greater energy diversity (particularly in the transportation sector), and less reliance on imported fossil fuels. Challenges largely center on environmental and social concerns associated with shale gas

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difference. See EIA Electric Power Monthly (October 2012) for more detail. Chapter 1 of this report addresses the issue of life cycle GHG emissions for various electric generating technologies.

[11] The U.S. Department of Energy reported that the number of heating degree days in the first quarter of 2012 were at the lowest level since record keeping began in 1895 (EIA 2012a).

[12] These rules include the Cross-States Air Pollution Rule (recently vacated, but backstopped by somewhat less restrictive requirements), the Mercury and Air Toxics Standard, the Clean Water Act Section 316(b) Water Intake Structures, and the Coal Combustion Residual requirements. Numerous studies attempt to estimate the potential impacts of some or all of these rules after they take effect (see CRS 2011; CERA 2011; and Credit Suisse 2010).

[13] In a May 22, 2012 presentation to investors, for example, ArchCoal stated that half of the coal generation recently lost to low-cost natural gas could be recovered when gas prices rise back above $3/MMBtu (Slone 2012). AEP also noted in an October 24, 2012 news story that it had seen some fuel switching from natural gas back to coal due to rising natural gas prices (Reuters, 2012).

production, especially through hydraulic fracturing.[14] These concerns are acute in some states and increasingly on the docket for federal regulators in several agencies. Current federal regulations to protect surface and underground water resources are less onerous for hydraulically fractured gas production than they are for conventional oil and gas drilling, although many states are passing or updating rules quickly as drilling expands (see Chapter 2, UT 2012, Zoback 2010). Companies are also making greater voluntary efforts to ensure the likelihood that air, water, land, and other resources are protected—at least compared to the early days of hydraulic fracturing—although these efforts are still not practiced universally (see Chapters 2 and 3).

A more general concern for policy makers centers on the role of natural gas versus other sources of electricity in the future: low-priced natural gas could disrupt the development of advanced nuclear or renewable energy technologies, for example, and delay the date when they are cost competitive with traditional energy options. If natural gas prices rose substantially after the power sector had evolved to become more reliant on that fuel, the economy could be vulnerable to an expensive and "locked-in" power sector.

This report focuses on four topics. First, Chapter 1 addresses the full life cycle GHG emissions of shale gas compared to other power generation options. Questions about these "cradle-to-grave" emissions began to appear in 2011 with several reports claiming that shale gas had life cycle GHG emissions as high as, or higher than, coal.[15] Controversy remains over how much methane is released to the atmosphere during the process of producing natural gas, in general, and shale gas, in particular. Chapter 1 uses a new approach to advance the state of knowledge about the life cycle GHG emissions from shale gas based on analysis of highly resolved inventories of air pollutant emissions completely independent of the data sources used in previous research.

Second, Chapter 2 surveys the legal and regulatory trends associated with shale gas production at both the federal and state level. Although federal agencies are taking an active role in ensuring that shale gas is produced safely, Congress has imposed some limitations on what agencies can regulate. The state role in regulating unconventional natural gas production is more pronounced and varied. Chapter 2 summarizes trends in regulatory action at six major unconventional gas plays/basins: Barnett Shale play and Eagle Ford Shale play in Texas, Haynesville Shale play in Texas and Louisiana, Marcellus Shale play in New York and Pennsylvania, North San Juan basin in Colorado, and Upper Green River basin in Wyoming.

Third, Chapter 3 assesses environmental and community risks associated with unconventional natural gas production in the same six regions identified in Chapter 2. It focuses particularly on water issues and company practices that impact water. Public concern over environmental and safety issues has been severe enough in some areas to delay or halt plans to develop unconventional production.

[14] See, for example, SEAB (2011a and 2011b), MIT (2011), and UT (2012). There is some confusion surrounding hydraulic fracturing and the potential for environmental impact. Those in industry typically use the term in a focused way, referring to the brief period of time that a high-pressure mixture of water, sand, and additives is being injected, and later, partially removed (flowback). The general public often takes a broader view and labels the entire process of producing unconventional gas or oil as hydraulic fracturing. Significant controversy results from the difference in semantics.

[15] See Lustgarten (2011) and Howarth et al. (2011), for example.

A GIS tool was developed to help evaluate:

- Water availability, use, and cost information
- Water flowback and produced water
- Best current practices for management.

Current practices and regulatory oversight need to be evaluated at a deeper level before the overall goal of determining the costs of acceptable practices can be achieved. Chapter 3 describes a comprehensive approach to evaluating risks and following practices so as to support greater public confidence.

In Chapter 4, we report on different U.S. electric power futures based on a variety of potential developments in technology, environmental protection, GHG mitigation, social license to operate, and gas demand outside the power sector. We use the National Renewable Energy Laboratory's (NREL's) Regional Energy Deployment System (ReEDS) to simulate the impact of these different futures, and benchmark information from Chapters 1–3 in the scenario analysis. Chapter 5 synthesizes findings and summarizes potential follow-on research.

1 Life Cycle Greenhouse Gas Emissions from Barnett Shale Gas Used to Generate Electricity

1.1 Introduction

According to the 2010 U.S. Greenhouse Gas Emissions Inventory (EPA 2012a), the natural gas industry[16] represents nearly a third of total methane emissions in the United States in 2010—the largest single category—and is also the fourth largest category of CO_2 emissions.[17] EPA, which produces the U.S. GHG inventory, significantly increased estimates of methane emissions from the natural gas industry for the 2009 inventory year, resulting from a change in its assessment of emissions from four activities, the most important of which were: well venting from liquids unloading (attributed only to conventional[18] wells by EPA); gas well venting during completions; and gas well venting during well workovers[19] (EPA 2011). The sum of these changes more than doubled the estimate of methane emissions from natural gas systems from the 2009 inventory compared to the 2008 inventory. EPA acknowledges what is well understood: the estimates of GHG emissions from the natural gas sector are highly uncertain, with a critical lack of empirical data to support GHG emission assessments (EPA 2011). This is especially acute for production of unconventional gas resources. Data gathering to support re-assessment of the EPA's U.S. GHG inventory and potential regulations is under way.

An emerging literature has attempted to estimate GHG emissions from unconventional natural gas production, based on the limited available information. Measurement of GHGs in the atmosphere, if they could be reliably attributed to specific sources, would be the ideal methodological approach. However, such measurements are expensive, attribution is challenging, and only one pilot study has been published to date based on measurements in one gas field—which, since the time of measurement, has implemented new practices based on changing state regulations (Petron et al. 2012). The state of the practice employs engineering-based modeling, based on as much empirical information as is possible to assemble.

Much of this emerging literature is guided by the methods of life cycle assessment (LCA), which in this context aims to estimate all GHG emissions attributable to natural gas used for a particular function: electricity, transportation, or primary energy content (e.g., heat). Attributable emissions are those from any activity in the process chain of producing the natural gas—from exploration and well pad preparation to drilling and completion—processing it to pipeline quality, transporting it to the location of end use, and combustion. In addition, the construction, operation and maintenance, and end-of-life decommissioning of the end-use technology are also considered.

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[16] For purposes of the GHG Inventory, the natural gas industry includes exploration, production, processing, transmission, storage, and distribution of natural gas to the end user (EPA 2011).

[17] In 2010, total U.S. GHG emissions have been estimated as 6,822 Tg or million metric tons CO_2e (EPA 2012a). Of this total, 84% were from CO_2, with most of the remaining (10%) from methane. Direct emission from the combustion of fuels, including natural gas, for electricity generation contributes 2,258 Tg CO_2, or 33% of total GHG emissions. Natural gas systems contribute 247 Tg of CO_2e, or 3.6% of total emissions, 87% from emissions of methane.

[18] Defined as any non-stimulated well. This report follows EPA (2011) in recognizing "that not all unconventional wells involve hydraulic fracturing, but some conventional wells are hydraulically fractured, which is assumed to balance the over-estimate."

[19] The frequency of which has since been reduced from 10% of wells per year to 1% of wells per year (EPA 2012b).

LCAs are typically performed to compare the results from one system to another.[20] The focus of this chapter is to advance understanding of GHG emissions from the production and use of shale gas in the context of the electric power sector as compared to generation of electricity from conventionally produced natural gas. Natural gas once processed for pipeline transmission to end-use customers is a homogenous product, undifferentiated by source. End-use combustion of the natural gas has, by far, the largest contribution to life cycle GHG emissions (as is true for any fossil-fueled combustion technology); but is not a point of differentiation between conventional and unconventional natural gas. Therefore, this study focuses on the activities associated with production of natural gas because they are the points of potential differentiation between unconventional and conventional natural gas.

We additionally focus on emissions from natural gas processing, given current regulatory and scientific attention to emissions from the natural gas industry and opportunity provided by the unique data sources employed in this study. Furthermore, we rely on the multitude of previously published LCAs of conventionally produced natural gas, updated for recent changes in understanding (EPA 2011; EPA 2012b) and harmonized for methodological inconsistency, as embodied in our publication (O'Donoughue et al. 2012), for comparison to the results of this study. We also compare our results to those for coal-fired electricity generation based on a systematic review and harmonization of that LCA literature, because coal has been the largest source for electricity in the United States over the last 50-plus years (Whitaker et al. 2012).

Prior research comparing life cycle GHG emissions of electricity generated from shale gas to conventional gas has been inconclusive and remains highly uncertain. Both the magnitude and direction of difference reported in these publications vary (Howarth et al. 2011; Burnham et al. 2012; Jiang et al. 2011; Skone et al. 2011; Stephenson et al. 2011; Hultman et al. 2011). This is despite their reliance on very similar data sources (mostly EPA's GHG emission inventory and supporting documentation). Uncertainty in the underlying data sources drives the uncertainty in published results. Furthermore, inconsistent approaches to data use and other assumptions thwart direct comparison of the results of these studies and the development of collective understanding.

Separately, the authors have examined this literature using a meta-analytical technique called harmonization that clarifies the collective results of this emerging literature by adjustment to more consistent methods and assumptions (Heath et al. 2012). In that publication, the authors elucidate differences between previously published estimates of life cycle GHG emissions from combustion of shale gas for power production and key sensitivities identified in this literature. Key sensitivities include EUR and lifetime (years) of wells; emissions and emissions reduction practices from well completion and workover; and emissions and emission reduction practices from well liquids unloading, all of which vary from basin to basin and from operator to operator. A key conclusion from the assessment of previous estimates of unconventional gas life cycle GHG emissions is that given current uncertainties, it is not possible to discern with a high level of confidence whether more GHGs are emitted from the life cycle of shale gas or conventional gas used for electricity generation.

[20] For interested readers, many texts describe LCA principles and methods, such as Horne et al. (2009) and Vigon et al. (1993).

In this chapter, we present results from a new method of estimating life cycle GHG emissions from shale gas that takes advantage of unusually detailed and rarely produced empirical data specific to a shale gas play and year. Our empirical data sources and approach differ significantly from previous efforts. Broadly, we use the methods of air quality engineering, life cycle assessment, and energy analysis to estimate GHG emissions attributable to the generation of electricity from shale gas produced from the Barnett Shale play in Texas in 2009, the latest year with available data. There are several unique aspects of this research as compared to previous natural gas life cycle assessments:

- Highly resolved estimates of GHG emissions from shale gas production and processing developed at site (facility) and source (equipment and practices) levels.
- Use of industry-supplied and regulator quality-assured data regarding equipment, practices, and emissions developed with very high participation rates.
- Development of a publicly available data set of county-level, extended gas composition analyses of produced (raw) gas demonstrating wide variability of methane and VOC content within the Barnett Shale formation.

It is critical to note that the new results reported here are not necessarily applicable to other plays or years. However, they are discussed in the context of other published literature, where the broad outlines of consistency found within this literature increases confidence in the results, albeit still hampered by many areas of uncertainty remaining to be addressed through further research.

Commercial production of shale gas began in the 1980s, starting in the Barnett Shale play in Texas. The Barnett Shale play continues to be a large source of gas, estimated at more than 6% of total U.S. natural gas production (Skone and James 2010). Data on production and processing activities in this 22-county[21] area (Figure 5) are some of the best available for any unconventional gas formation in the United States. For these reasons, the focus of the analysis of this chapter is shale gas produced from the Barnett Shale formation. As illustrated in Figure 5, the highest production occurred within the Dallas-Ft. Worth metropolitan area, which is in non-attainment for the National Ambient Air Quality Standard for ozone (and other pollutants).

[21] The Barnett Shale is sometimes referred to as consisting of 23 or 24 counties. However, this analysis focuses on the 22 counties with non-zero gas production for 2009 (TRRC 2012).

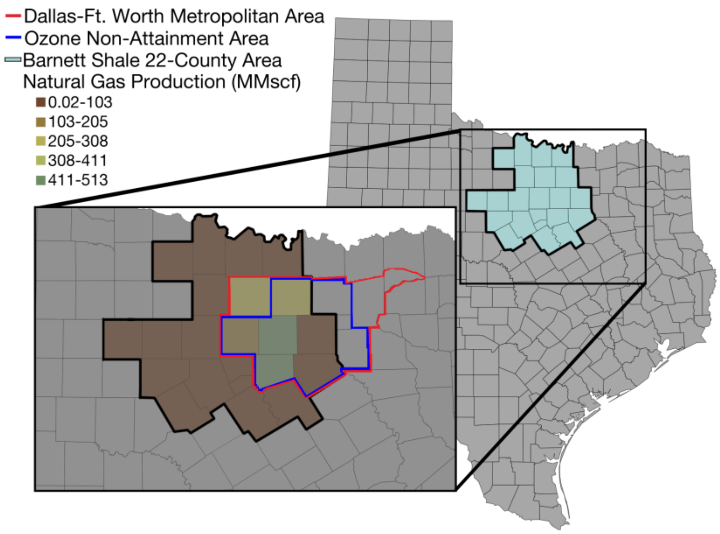


Figure 5. Counties with non-zero gas production from the Barnett Shale formation in 2009, and other demarcations of the Barnett Shale area in Texas (TRRC 2012)

1.2 Methods and Data

There are many different sources of GHG emissions in the natural gas industry (EPA 2011; ENVIRON 2010; API 2009), but the fundamental approach to estimating the magnitude of emission for all of them is:

$$[activity] * [emission\ factor] = [emission]$$

where the emission factor is in units of mass emission per unit activity, and "activities" for the natural gas industry range from counts of drilled wells or pieces of certain equipment to volume of natural gas produced, fuel combusted in an engine, or volume of water produced from a well (e.g., ENVIRON 2010; API 2009; EPA 1995). We call this approach *activity-based emission estimates*.

Different groupings of activity-based emission estimates lead to different types of results. *Inventories* aim to estimate emissions from a given chronological period, representing all activities occurring in that period. Inventories are developed with different foci: geographic, industrial sector, or pollutant. Few GHG emission inventories exist at higher spatial resolution than national, which aggregates industry- and pollutant-specific inventories produced at a national scale.

In contrast, LCAs aim to estimate all emissions attributable to a final product—here, a kilowatt-hour of electricity—scaling all the activities required over time and space to produce that unit of final product. Figure 6 depicts the scope of this LCA of electricity generated with natural gas, which covers all stages in the fuel cycle as well as the power plant's life cycle. As shown, this study combines an original inventory, for stages shown in blue, with best-available literature estimates for the remaining stages. Once co-products are separated from the produced gas, all emissions associated with their storage, processing, transport, and disposal or sale are considered outside of the system boundary for this study (as depicted with dashed lines).

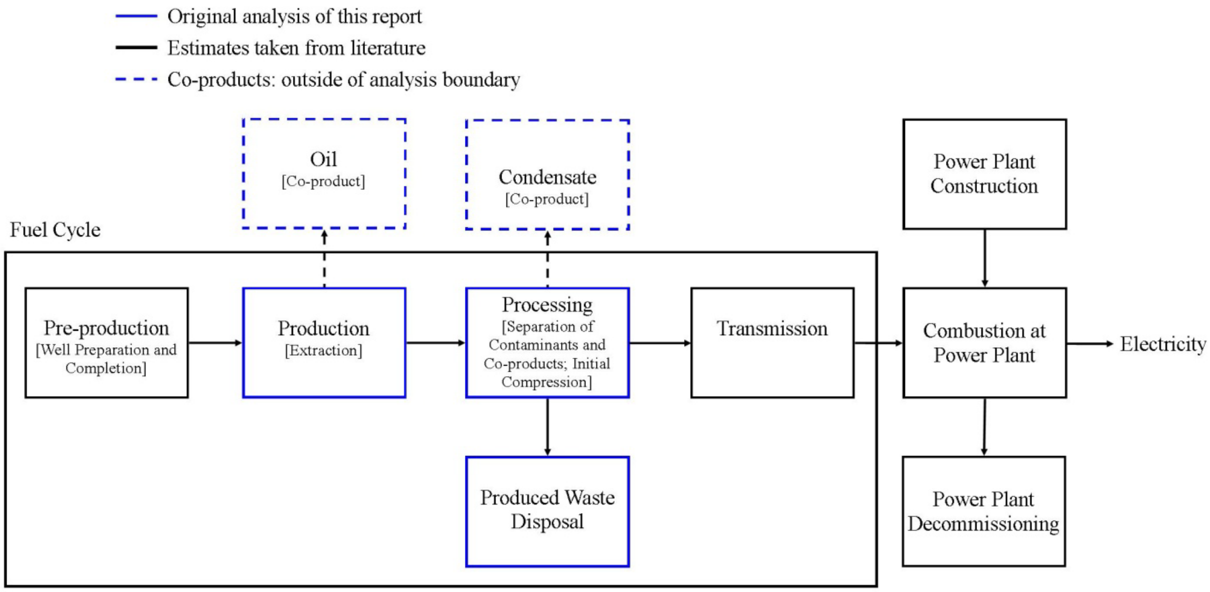


Figure 6. A life cycle assessment of electricity generated from natural gas involves estimating the GHG emissions from each life cycle stage

Because LCAs track the conceptual process chain—rather than the real supply chain—they typically model idealized activities, informed by as much empirical data on real conditions as possible. More than 30 LCAs of conventional natural gas follow this modeling philosophy (O'Donoughue et al. 2012). LCAs on shale gas that follow this approach include one employing a simplified, generic model of the industry (Stephenson et al. 2011); three assessing the U.S. national average or otherwise non-formation-specific conditions (Burnham et al. 2012; Skone et al. 2011; Howarth et al. 2011); and two assessing specific formations—Jiang et al. (2011) on the Marcellus formation and Skone et al. (2011) on the Barnett Shale.

More recently, some LCAs have leveraged EPA's national inventory of the natural gas industry's GHG emissions from a given year to simulate the process chain (Hultman et al. 2011; Venkatesh et al. 2011). These latter assessments benefit from emission estimates meant to be more closely related to actual performance; however, their estimates carry significant uncertainty given the current state of knowledge of activities and emission factors of this industry. In addition, results will change from year to year as the level of activity changes and may not reflect the life cycle of activities for a well (e.g., completions nationally in a given year may contribute a larger fraction of total emissions than what is reflective of their contribution within the life cycle of a single well).

In contrast to such approaches, this study translates estimates of VOC emissions to GHG emissions, capitalizing on a uniquely detailed inventory of VOC emissions and activities collected by the TCEQ. This approach enables a high-resolution GHG inventory for the production and processing of natural gas in the Barnett Shale play, within which individual GHG emissions from all relevant sources are estimated. Then, this annual inventory of the natural gas industry is translated into a longitudinal life cycle assessment for electricity produced from combustion of Barnett Shale gas. A brief summary of the approach is described below, with details provided in Appendix B.

1.2.1 Developing a GHG Emissions Inventory

Inventories of GHG emissions follow a long tradition of inventories for regulated air pollutants such as nitrogen oxides (NO_x) and VOCs that, in combination with sunlight, are precursors of ozone. Because of their role in demonstrating compliance with the National Ambient Air Quality Standard for metropolitan areas, the unit of analysis of these inventories is the county and large, so-called *point sources*. Point-source inventories contain detailed information related to all sources of emissions within specific facilities and are based on activity and characteristics information supplied by those facilities. Smaller, non-mobile sources (called *area sources*) are too numerous for regular, facility-specific information collection efforts and instead are tracked as a class, with emission factors (often simplified) correlating emissions with readily tracked activity data. The natural gas industry has many large point sources (including processing plants, compressor stations, and some production sites); the more numerous, smaller entities (including most production sites and some processing and transmission facilities) are classified as area sources.

Motivated by changing practices in the industry, in 2009, the TCEQ initiated a special inventory to collect detailed information on the activities and characteristics of the smaller entities in the natural gas industry that are normally part of the area-source inventory, similar to what is collected routinely from large point sources (TCEQ 2011). The purpose of the special inventory is to update and improve the TCEQ's estimates of emissions of regulated air pollutants from area sources, focused on the rapidly growing shale gas industry in the Barnett Shale area surrounding the metropolitan area of Dallas-Ft. Worth. The availability of the TCEQ's special inventory, in conjunction with its standard point-source inventory (TCEQ 2010), enables estimates of GHG emissions from activities within this important play at much finer resolution—by geography and entity—than is typically possible.

This study estimates GHG emissions from more than 16,000 individual sources detailed in three different TCEQ emission inventories:[22] the 2009 Point Source Inventory, 2009 Special Inventory, and 2008 Area Source Inventory (Pring et al. 2010). As shown in Figure 7, sources are characterized into profiles, which we further group into three general categories: combustion sources, potentially controllable leakage, and fugitives.[23] We differentiate between *potentially controllable leakage* and *fugitives*, where the former typically involves gas released from an isolatable emission point and therefore is potentially controllable, and the latter comes from more dispersed leaks that are less feasible to control. Many of the individual sources analyzed in this report are potentially controllable, as are many additional emissions in the fuel cycle, which come from completions and workovers, waste disposal, and transmission. For each profile, we estimate emissions with a tiered approach based on the availability of data. In general, primary (most accurate) methods are based on reported volumes, such as fuel combusted or gas emitted, whereas secondary methods are based on reported VOC emissions or average usage conditions. We use primary methods for 83% of sources, secondary for 15%, and profile medians for the remaining 1%.

[22] Detailed inventory data were received through personal communication (TCEQ 2012).
[23] Skone et al. (2011) state that 25% of compressor engines in the Barnett Shale area are electrically powered, which would require the inclusion of emissions attributed to the generation of that electricity as an additional category. However, no electrically powered compressor engines are listed in the TCEQ data provided, and personal communication with the TCEQ (TCEQ 2012) stated that few, if any, such engines exist in the area.

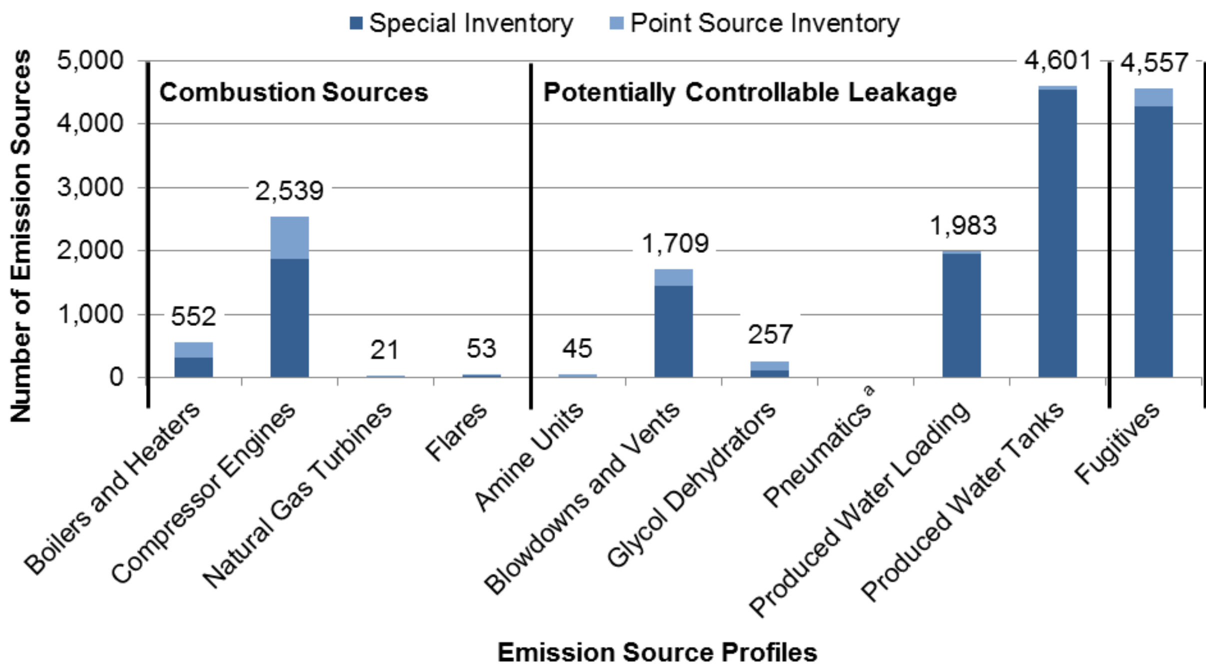


Figure 7. Greenhouse gas sources belonging to the natural gas industry in the 22-county Barnett Shale area; many are potentially controllable

[a]Pneumatics, from the area source inventory, have no count of individual sources

The central principle for translating a VOC emission inventory to one that estimates GHG emissions is the recognition that methane is a VOC,[24] albeit the slowest-acting one (Seinfeld and Pandis 2006). The key to translating VOC emission estimates to methane emissions is the availability of gas composition analyses reporting the proportion of methane, VOCs, and other gases (e.g., CO_2) within a sample. For validation purposes, the TCEQ requested many such gas composition analyses from reporting entities, which have been assembled into the largest known play-specific and publicly available set of gas-composition analyses. Organized by county, this database allows for estimation of methane and CO_2 content in gas emitted through venting and fugitive sources by ratio. It is well understood by geologists, petroleum engineers, investors, and others that gas composition varies within a geologic shale gas basin (e.g., Bullin and Krouskop 2008; Bruner and Smosna 2011); however, this is the first LCA or GHG emissions inventory to explore the implications of this variability.

In addition, other valued hydrocarbon products, such as condensate and oil, are created during the production and processing of natural gas. A principle of LCA research called co-product allocation dictates that the burdens of a system should be shared among all valued products from that system (e.g., Horne et al. 2009). In this study, emissions are allocated with respect to their share of the total energy content of all products from the fuel cycle. In addition to weighting the emissions from each source according to associated condensate and oil production, this means

[24] The VOCs typically tracked in Texas and national (EPA) regulations are non-methane, non-ethane VOCs. Accordingly, this report follows standard convention and refers to the set of non-methane, non-ethane hydrocarbons as VOCs. However, measurements of the composition of a gas sample (a so-called "extended analysis") include methane.

that the 25% of the sources in the TCEQ inventories that are associated only with the storage and handling of these co-products (e.g., condensate tanks) have been omitted.[25]

1.2.2 From Inventory to LCA

The GHG emissions inventory estimated here draws mainly from the TCEQ Special Inventory and Point Source Inventory for sources within natural gas production and processing life cycle stages (see Figure 7) (TCEQ 2010, 2011). Natural gas *production* relates to ongoing activities for the extraction of gas at wellheads. Natural gas *processing* relates to ongoing activities for the conversion of the produced gas to the required quality, composition, and pressure for pipeline transport.[26] In addition, the TCEQ area-source inventory is leveraged to estimate emissions associated with some activities at produced water *disposal* sites (Pring et al. 2010).[27]

Emissions from all sources within a fuel cycle phase are summed and then divided by the energy content of gas produced in that year to estimate an emissions factor in terms of mass of GHG emissions per unit of energy content of gas. Gas production statistics come from the Texas Railroad Commission for the 22-county play (TRRC 2012). Each GHG is weighted by its Intergovernmental Panel on Climate Change (IPCC) 100-year global warming potential according to standard procedure to normalize to units of CO_2e (Forster et al. 2007).[28] However, these emission factors cover only a portion of the natural gas fuel cycle, which itself is a subset of the life cycle of electricity generation from natural gas (Figure 6). Therefore, although the inventory data provide an important addition to the relatively sparse information about GHG emissions from shale gas development, literature sources are relied on for data on other emissions sources and life cycle stages—including sources such as completions, workovers, and liquids unloading—where there is considerable controversy currently about activity factors, emission reduction measures, and the magnitude of emissions.

Additional fuel-cycle stages include pre-production and transmission. *Pre-production* consists of one-time or episodic activities related to the preparation of wells, including the drilling and construction of well pads and wells, hydraulic fracturing to stimulate production, and well-completion activities. Emissions factors for these one-time activities, gathered from open literature (Santoro et al. 2011; EPA 2011; EPA 2012b; Skone et al. 2011), must be amortized over the lifetime production (EUR) of a well. *Transmission*, also estimated from literature data (Skone et al. 2011), involves the transport of processed gas to the power plant.[29]

This study combines fuel cycle emission factors into a full LCA by assuming a standard efficiency of conversion to electricity and adjusting for natural gas losses throughout the fuel cycle due to both leakage to the atmosphere and the use of production gas as fuel. This study

[25] Sources contained within the TCEQ inventories that are considered outside of the system boundary collectively represent 60% of total reported VOC emissions but a much smaller fraction of GHG emissions.
[26] Processing can occur either at wellheads or at separate processing facilities.
[27] Emissions from produced water tanks at produced water disposal sites are tracked by TCEQ; transport of the produced water to the disposal site and operation of engines at these sites are not considered in this analysis.
[28] Global warming potentials (GWP) are also reported by the IPCC for a 20 year horizon and 500 year. The 100-year GWP is used in this study to ensure consistency with the standard practice in LCA and GHG emission inventories. Results based on alternative GWPs or other metrics of climate impact could be developed based on the results reported here.
[29] Following Skone et al. (2011), we consider the final step of processing as initial compression to pipeline pressure.

assumes combustion in a modern natural gas combined-cycle facility with thermal conversion efficiency of 51% (higher heating value) to make the results comparable to the meta-analysis of electricity generated from combustion of conventionally produced natural gas (O'Donoughue et al. 2012). Many natural gas-fired power plants do not operate at this efficiency, and the results reported here can be easily adjusted to apply to alternative conditions. GHG emissions from power plant construction and decommissioning are also considered, amortized over the lifetime generation from the facility (O'Donoughue et al. 2012). Data on emissions from *combustion at power plant*, *power-plant construction*, and *power-plant decommissioning* come from open literature (Skone et al. 2011; Skone and James 2010).

The final estimate of life cycle GHG emissions is calculated as the sum of the estimated emissions from each life cycle stage, adjusted by the thermal efficiency and relevant production losses, as appropriate for each stage and detailed in the appendix. These full life cycle emissions are expressed in units of mass CO_2e per kilowatt-hour generated.

1.3 Results

In this section, we present and discuss key findings. Because of their relevance to the current debate about GHG emissions from natural gas, the full LCA results are presented first, followed by a comparison of these results to other published estimates. Then, the primary research contribution of this chapter is detailed: a high-resolution inventory analysis of the production and processing stages of the natural gas fuel cycle for Barnett Shale gas produced in 2009. Appendix B provides further results, including county-level analysis of production gas composition, allocation of emissions to co-products, and details supporting the presented results.

1.3.1 Life Cycle Emissions

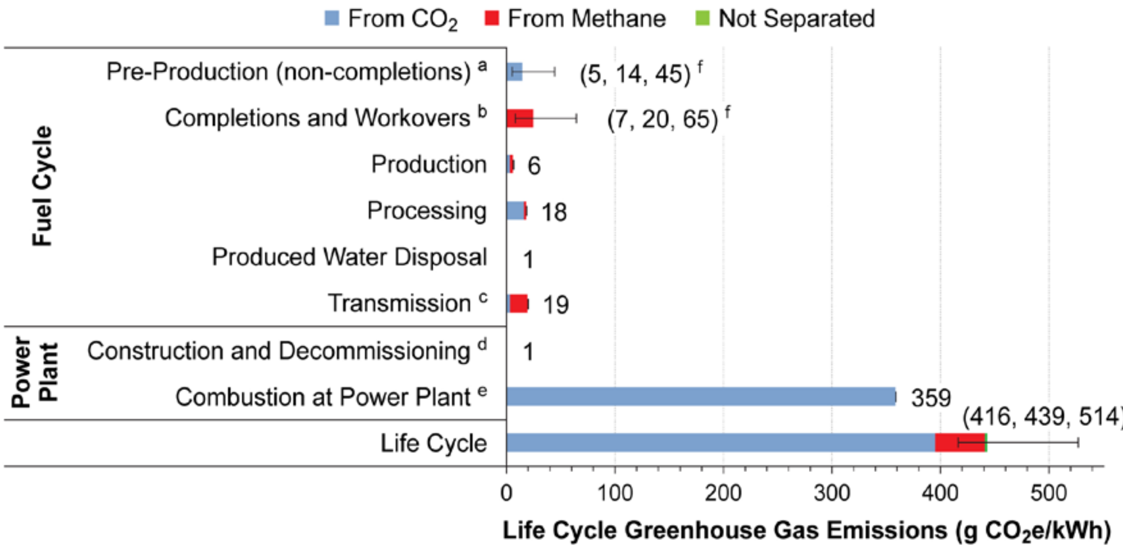
GHG emissions from the natural gas fuel cycle are a focus in the public sphere and of the novel analysis of this study. However, the functional unit of the fuel cycle—a unit of energy content of processed natural gas delivered to the end user—is not easily comparable to that for other fuels for end-uses other than direct heating. Use of natural gas in the electric sector is the focus of this report and is the market for about 30% of natural gas production in 2011 (EIA 2012). Some have argued that future production of unconventional natural gas will only displace dwindling production of conventional natural gas (e.g., Howarth et al. 2012). However, others believe that natural gas could displace existing and new coal as fuel for electricity generation (e.g., Venkatesh et al. 2011; Hultman et al. 2011). Comparisons of the results to both alternatives are provided in the next section.

First, it is critical to emphasize the importance of GHG emissions from combustion at the power plant in the life cycle of natural gas electricity generation. The GHG emissions from combustion are primarily determined by the carbon content of the fuel and the efficiency of converting fuel (chemical) energy to electrical energy. Regardless of whether natural gas comes from conventional or unconventional sources, its chemical and thermal properties once processed are indistinguishable. With regard to carbon content of the fuel, coal has about 75% more carbon per unit fuel energy than gas. Regarding efficiency, when considering new power plants, most new natural gas generation assets will likely be natural gas combined-cycle, which has a characteristic higher heating value efficiency of 51% (O'Donoughue et al. 2012). This efficiency, chosen to maintain consistency with other studies for comparison purposes, does not reflect the existing fleet of natural gas plants, but rather, it is characteristic of a modern, state-of-the-art facility. The existing fleet of coal power plants has an efficiency of close to 34% (Hultman et al. 2011), whereas new plants of either supercritical or integrated gasification combined-cycle designs will reach near 40% (MIT 2007). The efficiency improvement for natural gas combined-cycle plants over old or new coal plants is substantial, especially considering the inherent difference in carbon content of the two fuels (absent any coal decarbonization).

Assuming 51% efficiency for natural gas combined-cycle and 50 g CO_2/MJ carbon intensity of natural gas yields an estimate of nearly 360 g CO_2/kWh from combustion at the power plant. Other stages in the life cycle of the power plant (e.g., construction and decommissioning) add very little (~1 g CO_2e/kWh) to life cycle GHG emissions of electricity generation for fossil-fuel facilities because those emissions are amortized over lifetime generation.

Including the 2009 Barnett Shale fuel cycle emissions compiled in this study, total life cycle GHG emissions from natural gas combined-cycle electricity are estimated to be about 440 g CO_2e/kWh (Figure 8). Of this total, about 18% of life cycle GHG emissions (or 78 g CO_2e/kWh) are embodied in the fuel cycle of Barnett Shale gas, as defined in Figure 7. These fuel cycle emissions from unconventional gas are comparable to those estimated from the fuel cycle of conventional gas, which O'Donoughue et al. (2012) find have a median estimate of about 480 g CO_2e/kWh in the existing literature after methodological harmonization. (See the next section for further discussion and comparisons.) About 10% (or 42 g CO_2e/kWh) of life cycle emissions result from emissions of methane, mostly through venting during completion and workover and from the natural gas transmission pipeline network. These results are calculated assuming a base-case EUR of 1.42 bcf produced over the lifetime of a well, which is the play-average EUR used by the U.S. Energy Information Administration in their National Energy Modeling Systems (NEMS) model (INTEK 2011).

The results are fairly sensitive to alternative estimates of Barnett Shale well EUR, which other studies have found to be one of the most influential parameters on life cycle GHG emissions (Burnham et al. 2012; Stephenson et al. 2011; Skone et al. 2011; Jiang et al. 2011). Adjusting all one-time and episodic emissions by lower- and upper-bound estimates of well-level EUR (INTEK, 2011) yields estimates of life cycle GHG emissions that vary by nearly 100 g CO_2e/kWh. Figure 8 displays the use of reported lower- and upper-bounds of well-level EUR for the Barnett Shale play (INTEK 2011) of 0.45 and 4.26 bcf/well, respectively. Life cycle GHG emissions then range between about 420 and 510 g CO_2e/kWh owing to the tested variability in assumed EUR.



[a] Although lower estimates for this stage have been published, reported emissions increase as the comprehensiveness of processes considered increase. So we use the highest published estimate for this stage that provided results in a form that could be adjusted by EUR (Santoro et al. 2011).
[b] Based on EPA (2011) estimate of 9,175 Mcf natural gas emission/completion, 1% of wells/year workover rate (EPA 2012b), 30-year assumed lifetime (Skone et al. 2011), and 22-county, Barnett Shale average natural gas molecular weight of 20.1 lb/lb-mol and methane mass fraction of 66.2%.
[c] Based on Skone et al. (2011)
[d] Based on Skone and James (2010)
[e] Based on Skone et al. (2011)
[f] Multiple estimates, in parentheses, pertain to high EUR, base-case EUR, and low EUR, respectively. Single estimates pertain to stages without sensitivity to EUR. The error bar is plus or minus the total bar length (life cycle GHG emissions).

Figure 8. Combustion at the power plant contributes the majority of GHG emissions from the life cycle of electricity generated from Barnett Shale gas

1.3.2 Comparisons to Other Studies

There are three important points of comparison for the life cycle GHG emission results presented here:

1. Previous estimates for electricity generated from shale or other unconventional gas
2. Previous estimates for electricity generated from conventional gas
3. Previous estimates for electricity generated from coal.

Direct comparison of the results of LCAs is hindered by the sensitivity of results to alternative assumptions of key parameters and other methodological considerations. Harmonization, which is a meta-analytical approach to enable more direct comparison, has been demonstrated for a wide range of electricity generation technologies (e.g., Burkhardt et al. 2012; Warner and Heath 2012). For coal-fired electricity generation, Whitaker et al. (2012) harmonized 164 estimates from 53 LCAs on four coal generation technologies (i.e., subcritical, supercritical, integrated gasification combined cycle, and fluidized bed). More recently, this approach has been applied to the LCA literature on natural gas-fired electricity generation, where estimates from 42 LCAs on conventionally produced natural gas (O'Donoughue et al. 2012) and 6 shale gas LCAs (Heath et al. 2012) have been harmonized. Results from these studies are used for comparing results of this report to those in the literature because they ensure fair and consistent comparisons and enable insight useful for broad decision-making.[30] It is important to note that the results of this study were developed using the same key assumptions and system boundaries as in the harmonization of the literature estimates for conventional and shale gas—and, more broadly, with those for coal.

Figure 9 displays the results of this chapter's analysis (base case and EUR sensitivity)—which estimates life cycle GHG emissions from Barnett Shale gas produced in 2009 and combusted to generate electricity in a modern natural gas combined-cycle turbine—compared to other estimates, which are based on a systematic review and harmonization of existing literature. Compared to other estimates for shale gas electricity generation, the base case results of this methodologically independent assessment are near the 25th percentile of harmonized estimates, which is similar for the comparison to harmonized conventional natural gas estimates. High and low EUR scenarios are also within the range of previous estimates for shale and conventional gas life cycle GHG emissions. The results are also found to be considerably lower than those for coal—nearly half of the median estimate of 980 g CO_2e/kWh (Whitaker et al. 2012), even under low EUR conditions.

[30] Estimates of life cycle GHG emissions for specific facilities can legitimately differ from those produced through harmonization. See Heath and Mann (2012) and other harmonization articles in the Special Issue on Meta-Analysis of LCA in the *Journal of Industrial Ecology* (http://jie.yale.edu/LCA-meta-analysis) for further discussion.

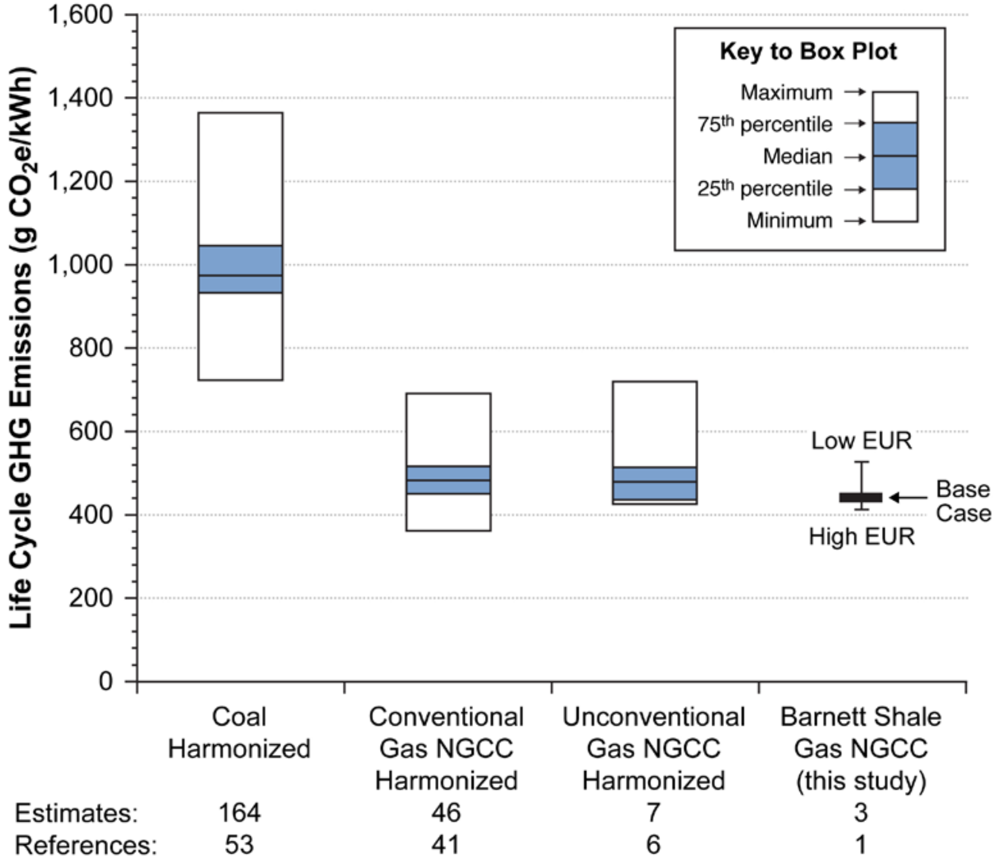


Figure 9. Estimate of life cycle GHG emissions from 2009 Barnett Shale gas combusted to generate electricity in a modern natural gas combined-cycle (NGCC) turbine compared to previously published estimates for unconventional (mostly shale) gas, conventional natural gas, and coal after methodological harmonization. [31]

Notes: EUR = estimated ultimate recovery, or lifetime production; NGCC = natural gas combined-cycle turbine

The rest of this section briefly reviews the key differences that could explain the relationship between the results from this study and those from other shale gas LCA literature. More detailed discussion of each of the existing shale gas life cycle GHG emission estimates can be found in Heath et al. (2012). Differentiating factors that tend to reduce estimates of life cycle GHG emissions for our study compared to some others include: equitably sharing the burdens of natural gas production with valuable co-products; not considering nitrous oxide emissions throughout the life cycle or non-CO_2 emissions from power-plant combustion; not considering embodied GHG emissions of purchased fuels; and not considering transport of produced water to disposal wells. None of the following factors are considered significant points of

[31] See O'Donoughue et al. (2012), Heath et al. (2012) and Whitaker et al (2012) for further description of the review and harmonization of estimates of life cycle GHG emissions from electricity generated from conventional natural gas, unconventional (mostly shale) gas and coal, respectively. The studies reviewed and harmonized in Heath et al. (2012) for unconventional (mostly shale) gas are: Howarth et al. (2011); Burnham et al. (2012); Jiang et al. (2011); Skone et al. (2011); Stephenson et al. (2011); Hultman et al. (2011).

underestimation: negligible impacts found in previous analyses,[32] contributions only to the fuel cycle (which represents 18% of total life cycle emissions), and negligible quantities of relevant sources.[33] Differentiating factors that tend to increase life cycle GHG emission estimates for particular literature estimates compared to ours include: higher natural gas leakage estimates (Howarth et al. 2011; Burnham et al. 2012; Skone et al. 2011; Hultman et al. 2011; Jiang et al. 2011); higher estimate of methane content of produced gas (Jiang et al. 2011; Burnham et al. 2012; Skone et al. 2011; Hultman et al. 2011); and inclusion of natural gas distribution for transport of gas to the power plant[34] (Jiang et al. 2011; Howarth et al. 2011; Hultman et al. 2011). On the other hand, EURs considered in this chapter are considerably lower than for other studies. This is especially true for the sensitivity analyses conducted by this and other studies, where the low-bound case for all other studies is at least twice the lower-bound estimate reported by EIA for the Barnett Shale play (INTEK 2011).[35]

A key distinguishing feature of the practices typically assumed for conventional as compared to unconventional wells is liquids unloading (i.e., periodic removal of liquids and other debris from a well). EPA has found that this practice occurs frequently—31 times per year on average (EPA 2011)—every year in the life of a well. And emissions from this practice, even when amortized over lifetime production of a well as in LCAs, are significant (e.g., Burnham et al. 2012). A recent survey of 91,000 wells by two industry associations suggests that at least for this sample, emissions from liquids unloading are nearly 80% lower than EPA's estimate (Shires and Lev-On 2012). Not only is the magnitude of emissions from liquids unloading controversial, but the same industry survey suggests that liquids unloading is also practiced on unconventional wells, reversing previous assumptions (Shires and Lev-On 2012). If liquids unloading were practiced on Barnett Shale wells,[36] then life cycle GHG emissions under average-EUR conditions would increase between 6 and 28 g CO_2e/kWh depending on the emission rate assumed[37] and potentially as high as 100 g CO_2e/kWh under low EUR conditions.

1.3.3 Fuel Cycle Methane Losses

Throughout each stage of the fuel cycle, a portion of the produced gas is used or lost: gas is used as a fuel for combustion activities, and it is lost when it leaks to the atmosphere either through potentially controllable leakage or fugitive emissions. As a potent GHG, methane emitted to the atmosphere is especially important to understand.

[32] For example, Skone et al. (2011) find that nitrous oxide contributes 0.04% to the total life-cycle GHG emissions for a natural gas combined-cycle plant. They also found that nitrous oxide and methane contribute 0.001% and 0.004%, respectively, to the GHG emissions from the energy-conversion facility (which primarily consist of fuel combustion emissions) for a natural gas combined-cycle plant.
[33] Fewer than ten engines in the inventory are identified as using purchased fuels (i.e., gasoline or diesel).
[34] To approximate an upper bound for such an omission, consider that even doubling the estimated emissions from transmission adds only 19 g CO_2e/kWh, or about 4%, to the total life-cycle GHG emissions.
[35] Base-case EURs were 3, 3.5, 3, 2.7, and 2 bcf for Howarth et al. (2011) (average of estimates reported in Table 1), Burnham et al. (2012), Skone et al. (2011), Jiang et al. (2011) and Stephenson et al. (2011), respectively. Lower bounds tested were 1.6, 2.1, 2.7, and 1 bcf for Burnham et al. (2012), Skone et al. (2011), Jiang et al. (2011), and Stephenson et al. (2011), respectively.
[36] Assuming 30-year well lifetime (Skone et al. 2011), 1.42 bcf EUR (INTEK, 2011), and 12% emission reductions (Burnham et al. 2012).
[37] The low estimate assumes an emission rate according to Shires and Lev-On (2012), whereas the high estimate assumes an emission rate according to EPA (2011).

This section reports two related metrics, each important for different purposes. The first metric we refer to as *natural gas losses*, which signifies the percentage of produced natural gas either lost or consumed along the fuel cycle, expressed in units of volume natural gas lost per volume natural gas produced.[38] The second metric we refer to as *methane leakage,* which signifies the volume of methane released to the atmosphere in relation to the amount of gas produced, expressed in units of volume methane emitted per volume natural gas produced. A leakage rate reported in these units enables rapid estimation of methane emissions based on a known amount of produced natural gas.

Based on the analysis of TCEQ inventories for natural gas production and processing emissions, as well as published estimates for other fuel cycle phases, this study estimates that 1.5% of produced gas is emitted to the atmosphere before reaching the power plant (see Table 1). Much of this is potentially preventable, with an additional 5.6% of produced gas consumed along the process chain as fuel for different types of engines. Based on the estimated methane content of this produced gas, this equates to a *leakage rate* across the fuel cycle of 1.3% methane volume per volume of natural gas processed, based on the assumed play-average EUR of 1.42 bcf/well. Because of the contribution of one-time emissions to these results, they are sensitive to EUR; low EUR corresponds to an estimated 2.8% methane leakage rate and the loss of 8.9% of produced gas across the fuel cycle, whereas high EUR corresponds to an estimated 0.8% leakage and 6.5% losses.

Table 1. Loss of Produced Gas along the Fuel Cycle[a]

	Completions and Workovers[b]	Production	Processing	Transmission[c]	Total
Extracted from Ground	100.0%				100.0%
Fugitive Losses	–	0.1%	0.0%	0.5%	0.6%
Potentially Controllable Leakage	0.8%	0.1%	0.0%	0.0%	0.9%
Combusted as Fuel	–	0.9%	3.9%	0.8%	5.6%
Delivered to Power Plant					92.9%

[a] Reported as volume of natural gas consumed or lost per volume of natural gas produced
[b] See footnote to Figure 9
[c] From Skone et al. (2011)

1.3.4 Air Pollutant Emissions Inventory-Based GHG Emissions Estimates

This study develops emissions factors for the production and processing stages of shale gas development based on original estimates of GHG emissions from TCEQ inventories and the Texas Railroad Commission's production statistics. These emission factors are shown in Figure using the functional unit of grams CO_2e per mega-joule of natural gas (i.e., g CO_2e/MJ).

[38] Although the use of natural gas in production and transportation processes is for beneficial purpose, it nonetheless represents the loss of a potentially marketable product. For instance, increasing the efficiency of engines at pipeline booster stations would increase the amount of product delivered to the end user. From this perspective, we employ the simplified terminology of "loss" of natural gas to include its use prior to sale to an end user.

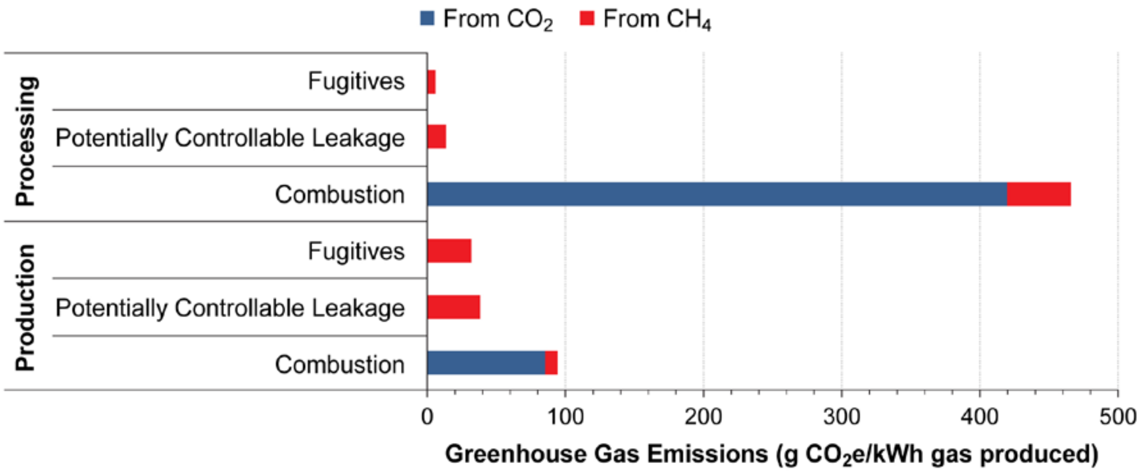


Figure 10. Inventory-based analysis of production and processing fuel cycle stages showing that the majority of GHG emissions are CO_2 resulting from combustion, although the CO_2e from methane emissions is significant

Most noticeably, the majority of GHG (CO_2e) emissions in both of these life cycle stages comes from CO_2 emissions from combustion sources. These emissions represent 53% of the total GHG emissions for the production stage and 87% for the processing stage. In the production stage, 90% of CO_2 emissions come from a large number of four-cycle rich-burn engines, nearly all of which are not normally individually tracked in the point-source inventory. Of the 1,564 compressor engines contributing to CO_2 emissions during natural gas production, only seven are reported to the point-source inventory, with the vast remainder of sources (and 99.9% of the CO_2 emissions) being reported only in the special inventory. Although the point-source inventory is intended to cover major emissions sources, the large number of individually smaller sources that are only captured by the special inventory play an important role in the GHG emissions from natural gas production in the Barnett Shale play. In the processing stage, 49% of CO_2 combustion emissions come from 405 4-cycle, lean-burn engines; 21% from 273 4-cycle, rich burn; 20% from 552 external-combustion boilers and heaters; and the remaining CO_2 emissions come from natural gas turbines, other compression engines, and equipment flares. In contrast to the production stage, 76% of these sources—representing 79% of the CO_2 emissions—are covered by the point-source inventory. Direct emission of CO_2 from fugitives and from processing (to achieve pipeline-quality specifications) is negligible but included for completeness.

Of the remaining GHG emissions, more methane emissions come from potentially controllable gas leakages than from fugitives. Specifically, only 41% of methane released in the production stage comes from fugitives. The 49% of methane coming from potentially controllable leakage in the production stage is dominated by emissions from pneumatic pumps and controls, which are a focus of recent EPA regulations. In the processing stage, fugitives make up an even smaller proportion (10%) of overall methane leakage. Of the 21% of methane emissions in this life cycle stage coming from potentially controllable leakage, more than half comes from emissions from produced water tanks, and almost a third from emissions from glycol dehydrators. Despite only a small proportion of combustion emissions being methane, combustion activities still account for

69% of the total methane emitted in the processing stage as a result of the large numbers of engines.

1.3.5 Sensitivity to Gas Composition Analysis

Because it reflects a key differentiation of this study from previous analyses, this section explores the sensitivity of this study's results to assumptions about the composition of the produced gas. Specifically, this section compares the study's main results—which are based on county-specific gas composition estimates (see Appendix B)—with results based on two alternative assumptions about produced gas composition.

The first alternative calculates emissions using a play-level gas composition estimate, which reflects a production-weighted average of all county estimates with original data. The second alternative uses EPA's reported national average production gas composition (EPA 2011) as the estimated composition for all sources. The national average is used for comparison because most LCAs rely on this gas composition, even for play-specific estimates (e.g., Skone et al. 2011). Table 2 reports the difference in emission estimates for CO_2, methane, and CO_2e using these alternative gas composition analyses compared to this study's spatially explicit approach (main results).

Table 2. Effects of Alternative, Spatially Uniform Estimates of Gas Composition on Inventoried GHG Emissions for the Barnett Shale Play

	Difference from Main Results		
	CO_2	Methane	CO_2e
Production and Processing Combined			
Main Results	–	–	–
Barnett Shale Average	-0.5%	2.6%	0.2%
National Average	-3.5%	5.7%	-1.5%

The overall impact is negligible of using spatially explicit estimates versus the Barnett Shale average, which is a production-weighted average of individual estimates: the effect on the two different GHGs cancel out in terms of CO_2e. The impact of using national average gas composition estimates is larger, but still small. As shown by the difference in Barnett Shale average versus national average results, these impacts come not from shifting to uniform gas compositions, per se, but rather, from using gas composition estimates less reflective of the specific gas analyses obtained from locations within the Barnett Shale region.

However, estimates differ more substantially when looking at a finer scale, as shown in Table 3, which focuses on production-stage emissions estimates for the four top-producing counties in the Barnett Shale. Using Barnett Shale or national average gas composition can lead to estimates one-third lower or higher for Tarrant and Wise counties, respectively, compared to using the county-level average. This variation comes from the substantial difference in estimated gas composition across counties, also shown in the lower portion of Table 3 for the representative gas constituents of VOCs, CO_2, and methane. Note that Tarrant and Wise counties both deviate substantially from the Barnett Shale average, as well as from the national average.

Table 3. Effects of Alternative, Spatially Uniform Estimates of Gas Composition on Estimated Production Emissions at the County-Level

	Denton County[a]	Johnson County[a]	Tarrant County[a]	Wise County[a]	22-County Total	
Barnett Shale average vs. main results	12%	-5%	-33%	29%	1%	
National average vs. main results	15%	-11%	-36%	29%	-3%	
	Denton County[a]	**Johnson County[a]**	**Tarrant County[a]**	**Wise County[a]**	**Barnett Shale play average[b]**	**National average[c]**
Volatile organic compounds content[d]	18%	19%	6%	23%	16%	18%
CO_2 content[d]	2%	2%	1%	3%	2%	2%
Methane content[d]	63%	63%	80%	56%	66%	78%

[a] Only the four top-producing counties in the Barnett Shale play are shown.
[b] Production-weighted average across the 22 counties of the Barnett Shale play
[c] As reported in EPA (2011)
[d] Percentage by mass

These results have implications for developing more accurate GHG emission inventories at sub-national levels and any regulatory system that might seek to identify high emitters within plays. Furthermore, when detailed activity data at the site or source level are developed, these data should be matched by detailed gas-composition analyses for the most accurate outcomes.

1.3.6 Areas for Improvement in Understanding

The estimate of life cycle GHG emissions from gas produced from Barnett Shale in 2009 reported here advances our understanding through rigorous analysis of more than 16,000 sources of emissions and accounts for the known spatial heterogeneity in gas composition within the Barnett Shale play. However, future efforts should explore the sensitivity of the estimates herein to the many contributing parameters and several other aspects because further improvement remains.

Chief among the areas for improvement are a greater number of recent measurements of emission factors and statistically representative surveys of current practices characterizing GHG emissions from the natural gas industry. For instance, there is a critical lack of measurements of emissions for completion and re-completion (workover) activities that account for different physical and operational conditions based on use of reduced-emission completion equipment, variations in gas flow during flowback and initial production, and mud degassing (EPA 2011; Shires and Lev-On 2012; CERA 2011; Burnham et al. 2012). Likewise, better and more recent measurements of fugitive emissions from well and processing equipment, as well as pipelines at all stages—gathering, transmission, and distribution lines—are warranted because the existing data are sparse and old. The prevalence of emission-reduction practices (e.g., flaring) during completion, workover, and other activities is another area of considerable lack of empirical information and variability in current assumptions (Heath et al. 2012) that would improve understanding of life cycle GHG emissions.

Furthermore, if other well-specific information—such as annual and lifetime gas, condensate, oil, and produced water production, and lifetime workovers—were available and could be matched to the TCEQ emissions inventories, then fuel cycle and life cycle GHG emissions could be estimated at the well level. These results could allow for consideration of well-level variability, with implications for the design of efficient strategies to control emissions. In particular, given the substantial sensitivity of results to EUR (total life cycle GHG emissions differ from base results by -5% or +17% for upper and lower EUR estimates, respectively), better well-specific information on EUR will improve the precision of emissions estimates. However, EUR is neither geographically nor temporally constant; rather, it relates both to physical characteristics of natural gas deposits and to the (constantly evolving) technical and economic feasibility of recovery of that natural gas. An improved and sophisticated understanding of EUR is therefore necessary. Finally, production activity is often planned for a field based on a set of wells; when initial wells decline in production, they could be restimulated and other wells could be drilled within the same area (through new laterals or new surface sites). Considerable knowledge of these dynamics is currently lacking. Yet, it is important to understanding GHG emissions in the context of deployment strategies used by many large players.

We have assembled the largest publicly available database of gas composition analyses for a shale gas play, and the counties with highest production correspond to those with the greatest number of analyses. However, given the sensitivity of the study's county-level results to the gas composition, it appears to be warranted to devote further effort toward improving the availability of production gas composition analyses specific to a region of interest. A random-sampling campaign conducted by a third party would be an ideal match for the methods used in this chapter if they are deemed useful for future analyses. A nearer-term objective could be to simply increase the pool of gas analyses from any entity willing to make such data available. Results of such further investigation could have implications for developing more accurate GHG emission inventories at sub-national levels and any regulatory system that might seek to identify high emitters within plays.

Further investigation of emissions from liquids unloading from unconventional wells is also warranted given the potentially significant GHG emissions from this activity, as described above. An emissions sampling strategy that accounts for variability across geography, gas type, well type, operator size, and operational practices, among other factors, should lead to an improved understanding of the potential for GHG emissions from liquids unloading for conventional and unconventional wells. Additional activity data regarding frequency of unloading and how this might change over the lifetime of a well, proportion of wells requiring unloading, and prevalence and effectiveness of emission-reduction activities are necessary to develop a more complete understanding of the emissions from this practice. Finally, because emissions from this episodic activity are amortized over lifetime production for use in LCAs, more certainty in the estimate of EUR would improve the accuracy of life cycle emission estimates.

Practices in the natural gas industry change over time, as do resource characteristics. Estimates of GHG emissions should be periodically repeated to reflect those changing practices and characteristics, using the most up-to-date and accurate data on emissions, emission-reduction practices, resource characteristics and activities available. Estimates could also be developed for future conditions based on expected changes in practices due to, for instance, full implementation of promulgated regulations. Such estimates could be compared to goals for GHG emission reduction to highlight whether additional emission reductions are necessary to reach those goals.

Analogously, industry practices and resource characteristics vary by location owing to differences in, for instance, geology, hydrology and state regulations. Estimates of GHG emissions should be developed in other locations using as much geographically specific data and information as possible. Furthermore, GHG emissions will also differ by gas type—not only by broad categories such as conventional and unconventional, but also, by different types of each, e.g., shale, tight, and coal-bed methane for unconventional, and associated, onshore, and offshore for conventional. GHG emissions for each of these types should be characterized so that a more accurate understanding of drivers of variability (if any) by type can inform discussions of opportunities to reduce emissions.

Finally, the bottom-up, engineering-based inventory of emissions should be confirmed through top-down atmospheric measurements. Literature suggests that emissions are typically underestimated through bottom-up approaches compared to concentrations of those same pollutants in the atmosphere (e.g., Townsend-Small et al. 2012; Petron et al. 2012). This effect likely results not only from issues such as non-reported sources, but also from inaccuracies that inherently arise from the use of non-specific methods that depend on average or ideal conditions. Although source attribution is still challenging and these measurements are expensive, they provide a much-needed confirmation of when inventories are accurate and when updates and improvements are necessary to support sound decision-making.

1.4 Conclusions

The aim of this research is to advance the state of knowledge of life cycle GHG emissions from electricity generated from shale gas extracted from a specific play—the Barnett Shale play in north Texas—using data sources independent of those used in previous LCAs of natural gas. We leveraged inventories of regulated air pollutants collected and screened by the Texas Commission on Environmental Quality for a 2009 special inventory of the Barnett Shale gas production, processing, and transportation sectors and their regular point- and area-source inventories in the 22-county Barnett Shale area. We used data supplied by the industry to TCEQ regarding the emissions and characteristics of more than 16,000 individual sources. The TCEQ inventories are used to estimate VOC emissions, a precursor of ozone. VOC emission estimates were translated to methane and CO_2 emissions by using gas composition analyses that report proportions by mass of each constituent. This study compiled a large dataset of such gas composition analyses at the county level, enabling a quantitative accounting of the significant variability that exists within the play of methane, CO_2, and other compounds.

Based on the analysis of TCEQ inventories and the addition of missing life cycle stages not included in those inventories, this study estimates that electricity generated using a modern natural gas combined-cycle turbine combusting Barnett Shale gas produced and processed in 2009 is associated with about 440 g CO_2e/kWh generated, with a sensitivity range based on published high and low EURs of 420 to 510 g CO_2e/kWh. Thus, the life cycle GHG emission result is sensitive to the lifetime production of wells, where additional research would be helpful to more precisely estimate life cycle GHG emissions. Regardless of this uncertainty, however, this chapter's main conclusion is that life cycle GHG emissions from electricity produced from Barnett Shale natural gas lie within the range of previously published estimates for GHG emissions (after methodological harmonization) from electricity produced by either conventional or unconventional natural gas (O'Donoughue et al. 2012; Heath et al. 2012). Furthermore, this report's estimate of life cycle GHG emissions is less than half of the median of published estimates for coal-fired electricity generation (after methodological harmonization) (Whitaker et al. 2012). It should be noted that the estimate of life cycle GHG emissions developed here is not strictly applicable to other locations or years, and that several important aspects of uncertainty in the methods of this research should be improved through additional research. However, the broad agreement between the estimate developed here and those published independently for both unconventional and conventional gas increases confidence in our understanding of life cycle GHG emissions of natural gas used for electricity generation.

This study found that about 19% of base case life cycle GHG emissions results from the fuel cycle of Barnett Shale gas (pre-production through transmission). About 10% of base case life cycle GHG emissions are methane, mostly vented during completion and workover and released from the natural gas transmission pipeline network. Only 11% of life cycle GHG emissions depend on characteristics of shale gas (e.g., extraction techniques, composition); the vast majority of life cycle emissions are not affected by the type or origin of the gas because they occur after processing that has the function of creating a homogenous product.

With regard to the fuel cycle GHG emissions, which were the focus of the analytical effort of this chapter, the vast majority comes from CO_2—80% or more of which is emitted from combustion sources (mostly engines and turbines) in the production and processing stages. The majority of emissions coming from natural gas production activities is from sources not routinely tracked individually (because they do not meet regulatory thresholds) in a classic example of how important the more numerous small sources can be to total emissions and how challenging quantifying and reducing emissions from the natural gas industry will be for regulators. Only through special inventories, such as the one conducted in 2009 for the Barnett Shale area, is it possible to have the kinds of detailed information necessary to estimate source-specific emissions for the vast majority of production sources within this industry. By contrast, processing sources are typically larger, meeting the threshold for annual emissions reporting under the regular point-source inventory.

We find that methane leakage, though playing a smaller role in life cycle GHG emissions from this analysis of 2009 Barnett Shale gas as compared to others, comes mostly from what we have classified as potentially controllable sources, rather than from fugitives—with implications for the potential for GHG emission reductions in the natural gas industry. In gas production, 40% of methane released comes from fugitive sources; methane emitted from potentially controllable leakage in the production stage comes mostly from pneumatic pumps and controls, which are specifically addressed in recent EPA regulations. In the processing stage, fugitives make up an even smaller proportion (10%) of overall methane emissions. As for potentially controllable leakage in processing, half comes from emissions from produced water tanks and a third from glycol dehydrators.

Our method represents an improvement in accuracy by accounting for spatial differences in gas composition as compared to previous LCAs. For instance, methane content of raw gas from the top four producing counties ranges from 56% to 80%, with implications for how much methane is released in venting or fugitive emissions. Previous research has either used play-level average gas composition (e.g., Jiang et al. [2011] for the Marcellus) or the national average. For Barnett Shale total emissions, the difference in results between using county-level gas composition compared to a play-wide average composition is relatively small; however, the improvement is more significant compared to using national average composition.

The overall results for the Barnett Shale play are only marginally sensitive to the variability in gas composition across the play because of offsetting differences. But the variability observed in gas composition has implications for accurate estimation of GHG emissions at finer spatial resolution, monitoring programs, and regulatory strategies. This study found differences in GHG emission estimates at the county level compared to estimates using national average figures; furthermore, inventories of the level of detail of the special inventory provide an important piece of the overall story of emissions. Therefore, accurate usage of such detailed information needs to be matched by more detailed input information, notably gas composition analyses. The database assembled for this study is a first step toward developing more robust databases in the Barnett and other natural gas basins around the country.

Improvements can be made to the estimate produced here of life cycle GHG emissions for 2009 Barnett Shale gas used in a modern combined cycle electricity generator. But this study's methodologically independent estimate confirms previous research on shale gas electricity generation. In addition, it is similar to previous estimates for generation using conventionally produced natural gas, and it is less than half of that estimated in other studies for coal. Liquids unloading, which is typically assumed to occur only for conventional wells, accounts for most of the difference between this study's estimate and that developed based on meta-analysis and updating of more than 40 references reporting life cycle GHG emissions for electricity generated from conventionally produced natural gas. However, evidence has emerged suggesting that liquids unloading is also a practice applicable to unconventional wells. If confirmed for Barnett Shale wells in particular, then it means that the estimate reported here should be updated accordingly. The high carbon content and significantly lower thermal efficiencies of coal-fired power plants account for their substantially higher life cycle GHG emissions.

2 Regulatory Framework Governing Unconventional Gas Development

2.1 Introduction

Rapid development of unconventional natural gas in the United States in recent years has raised a number of important environmental concerns, including ground and surface water contamination; disposal practices for frac flowback, produced water, and other associated drilling wastes; impacts on local and regional air quality; methane leakage and venting rates; and increased traffic, noise, and other community impacts. It is clear that regulations have increased at virtually all levels of governance in response to the unconventional gas boom. Various commissions, advocacy groups, and research organizations have weighed in on the pros and cons of additional regulation, including two reports issued by the Secretary of Energy Advisory Board Shale Gas Production Subcommittee ("SEAB Subcommittee").[39] But questions persist regarding the sufficiency of these regulations across differing jurisdictions and the adequacy of compliance monitoring and enforcement in the face of rapid growth.

Because of the "distributed" nature of unconventional gas development and the substantial increase in wells in key basins,[40] local land-use conflicts have erupted in certain areas of the country that have led to restrictions and moratoria on drilling by state, county, and municipal governments, raising questions about the industry's continued social license to operate in specific jurisdictions[41] (Dryden 2012; Middlefield 2012). In response, some states—notably Pennsylvania—have recently enacted legislation to restrict the ability of local governments to

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[39] *See e.g.*, U.S. DOE, *Secretary of Energy Advisory Board Shale Gas Production Subcommittee, Ninety-Day Report,* (Aug. 11, 2011) and *Second Ninety-Day Report* (Nov. 18, 2011), http://www.shalegas.energy.gov/resources/081111_90_day_report.pdf; National Petroleum Council, *Prudent Development Realizing the Potential of North America's Abundant Natural Gas and Oil Resources* (2011), http://www.npc.org/NARD-ExecSummVol.pdf; Cardi Reports, *The Economic Consequences of Marcellus Shale Gas Extraction: Key Issue*s, prepared on behalf of Cornell University (Sept. 2011), http://www.greenchoices.cornell.edu/downloads/development/marcellus/Marcellus_CaRDI.pdf; Thomas Kurth, et al., "American Law and Jurisprudence on Fracing," Haynes and Boone, LLP (2010), http://www.haynesboone.com/files/Publication/3477accb-8147-4dfc-b0b4-380441178123/Presentation/PublicationAttachment/195a3398-5f02-4905-b76d-3858a6959343/American_Law_Jurisprudence_Fracing.pdf ; Bipartisan Policy Center, Energy Project, *Shale Gas: New Opportunities, New Challenges* (Jan. 2012), http://www.scribd.com/doc/95194795/Shale-Gas-New-Opportunities-New-Challenges; Charles G. Groat and Thomas W. Grimshaw, *Fact-Based Regulation for Environmental Protection in Shale Gas*, report prepared for the Energy Institute, University of Texas at Austin (Feb. 2012), http://energy.utexas.edu/images/ei_shale_gas_regulation120215.pdf; Rebecca Hammer, et al, *In Fracking's Wake: New Rules are Needed to Protect Our Health and Environment from Contaminated Wastewat*er, Natural Resources Defense Council (May 2012) http://www.nrdc.org/energy/files/Fracking-Wastewater-FullReport.pdf; International Energy Agency, Golden Rules for a Golden Age of Gas, 9-10 (May 29, 2012), http://www.worldenergyoutlook.org/media/weowebsite/2012/goldenrules/WEO2012_GoldenRulesReport.pdf (discussing the importance of public acceptance for continued expansion of unconventional gas development in the U.S. and abroad).

[40] For a graphic depiction of the rapid increase in shale gas wells in Pennsylvania, see U.S. Energy Information Administration, "Horizontal drilling boosts Pennsylvania's natural gas production," available at http://www.eia.gov/todayinenergy/detail.cfm?id=6390.

[41] Some national governments, including France and Bulgaria, have also banned hydraulic fracturing (BBC News 2012). For a list of current moratoria and bans, see Sierra Club, FRAC Tracker, http://www.sierraclub.org/naturalgas/rulemaking/.

regulate unconventional gas development.[42] Other states, such as Colorado, have engaged in multi-stakeholder processes to strengthen and continue to revise new rules for oil and gas development that have been embraced by multiple constituencies and paved the way for innovative legislation that is re-shaping the electric power sector in the state (COGCC 2008; Xcel 2012). See Textbox 1 for more on Colorado's recent experience. But even in those states, such as Colorado, where oil and gas development has been a feature of the landscape for decades, a number of communities have expressed concerns about the proximity and pace of unconventional gas development and are seeking to impose new restrictions on development.[43]

Text Box 1: Colorado's Clean Air-Clean Jobs Act

In 2010, then Governor of Colorado Bill Ritter introduced landmark legislation that fundamentally altered the energy make-up of the state's electric power sector. The legislation, HB 1365, also known as the "Clean Air-Clean Jobs Act," required regulated utilities to reduce emissions of nitrogen oxides by 70% to 80% or greater from 900 megawatts of coal-fired generation by 2018 and meet certain "reasonably foreseeable" environmental requirements, such as lower ozone standards. To meet these targets, the state's regulated utilities proposed a plan that included retiring aging coal-fired power units, retrofitting others with state-of-the-art clean technology, and expanding capacity for units powered by natural gas and renewable energy sources. The Act had broad support from a number of constituencies including local Front Range governments, local and national non-governmental organizations, Xcel Energy and the natural gas industry (CCC 2010; Xcel 2012). Importantly, much of this support can be tied to the state's decision to first put in place strong rules for the development of its oil and gas resources before introducing legislation that would very likely lead to increased production. Many believe there is still work to be done to ensure that production is done properly statewide, especially in the Front Range, where new production is taking hold that did not exist to the same extent in 2008. However, many point to the Colorado model as an example of collaboration, innovation, and leadership that can be replicated elsewhere.

In short, the regulatory landscape affecting unconventional gas development is complex, dynamic, and multi-layered. Going forward, there is a risk of increased regulatory fragmentation within and among gas-producing basins, as well as a lack of coordination among the different government entities responsible for regulating and ensuring compliance with various aspects of unconventional gas development, leading to additional uncertainty, gaps, redundancies, potential delay for producers, and under-enforcement.[44] At the same time, leading companies continue to

[42] 58 Pa. Cons. Stat. § 3218; see also CO SB 088, introduced unsuccessfully Feb. 16, 2012.
[43] For example, Boulder County, Resolution No. 2012-16 (Feb. 2, 2012); Colorado Springs, Steve Bach, Mayer of Colorado Springs, "Memorandum on Administration of the Use of Regulations Set Forth in Chapter 7, City Code," (Nov. 28, 2011); the City of Erie, Ord. No. 09-2012 (Mar. 7, 2012); and the city of Longmont, Ord. No. O-2012-18 (Dec. 20, 2011)—all enacted temporary moratoria on applications for oil and gas development.
[44] For a recent report that surveys state shale gas regulation and similarly finds significant variations among them, see Resources for the Future, "A Review of Shale Gas Regulations by State," http://www.rff.org/centers/energy_economics_and_policy/Pages/Shale_Maps.aspx.

develop and elaborate best practices[45] to control and/or mitigate some of the environmental impacts associated with unconventional gas development. Some of these corporate practices go beyond existing regulation and some have served as the basis for new regulations.[46] Although it is impossible to predict the precise mix of future regulation, it is likely that additional regulations will be adopted and implemented as unconventional gas development proceeds. These could affect the costs of producing unconventional gas, but without basin- and company-specific data, it is not possible to determine the amount of additional compliance costs associated with any particular regulatory scenario. This is an important area for future research.

This chapter examines the main federal, state, and local regulatory frameworks that govern unconventional natural gas development.[47] Specifically, this chapter focuses on requirements related to water withdrawals used for hydraulic fracturing, disclosure of chemicals used in hydraulic fracturing fluids, setbacks for wells, baseline water monitoring of surface water resources or water wells, well construction standards, "green" or "reduced emission" completions, storage of waste in closed-loop systems, and the disposal of produced water. It also examines state compliance monitoring and enforcement capabilities. The goal of the research was to identify changes and trends in the governing legal frameworks across the different basins, as well as key challenges going forward. Specific attention is given to regulatory uncertainty, fragmentation, gaps, and redundancies associated with the proliferation of new rules and regulations at multiple levels, as well as the implications of shifting public perception and support for gas development across various jurisdictions.

Due to time constraints, it was not possible to examine all impacts associated with gas development and corresponding regulatory responses. Key areas for future research include, for example, regulations aimed at reducing the risk of surface spills of acids and chemicals used in hydraulic fracturing, storm-water controls, open-pit requirements, and mitigation measures for truck traffic. Beyond the scope of this report is a complete discussion of the environmental and public health risks posed by unconventional gas development and an analysis of the extent to which the current regulatory and statutory regimes reduce such risks, or the extent to which voluntary implementation of best practices fill any gaps remaining.

The chapter focuses on six unconventional U.S. basins: Barnett Shale play and Eagle Ford Shale play in Texas, Haynesville Shale play in Texas and Louisiana, Marcellus Shale play in New York and Pennsylvania, North San Juan basin in Colorado, and Upper Green River basin in Wyoming. As Table 4 illustrates, each of these basins is marked by distinct resource, geologic, and hydro-geologic characteristics, and each has had different historical and contemporary

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[45] The term *best practices* used here has the same meaning as that used by the SEAB in that it refers to "improvements in techniques and methods that rely on measurement and field experience" (SEAB 2011a). Best practices are not static, but rather, continuously evolving, as evidenced by the rapid changes in technologies related to stimulation techniques, methane capture, and water recycling.

[46] See, for example, green completions, voluntary disclosure of chemicals used in hydraulic fracturing fluids, and reuse of produced and flowback waters. EPA specifically cited industry's voluntary use of green completions in promulgating recent federal standards to limit air pollution from new and modified stationary sources in the Crude Oil and Natural Gas Production Category (EPA 2012c).

[47] Statutes applying uniquely to federal lands or actions, such as the Federal Lands Policy and Management Act, National Environmental Protection Act, and Endangered Species Act, are not discussed. For a more complete description of the federal framework that applies to unconventional gas development, see EPA 2000 and Kurth 2010.

experiences with oil and gas development. Accordingly, unconventional gas development in each of these basins and jurisdictions poses a distinct set of environmental issues, and it is the subject of a different mix of state and local regulation.

Table 4. Description of Shale Plays and Basins Studied

Primary Designation	Secondary Designation	Hydrocarbon Resources	Interest for Study	Production Characteristics
Barnett Shale Play	District 5, North Texas	Mostly dry gas, shale	Original shale gas basin, history, water stressed, near urban areas	6,000–8,500 feet deep
Eagle Ford Shale Play	Oil Producing Counties, South Texas	Oil, NGLs and gas, shale	High activity, resource diversity, water stressed	Oil 4,000–8,000 feet, NGLs/gas 8,000–12,000 feet deep, average thickness 450 feet
Haynesville Shale Play	DeSoto Parish, Louisiana	Mostly dry gas, shale	Second-largest shale gas reserves in U.S., active production	10,500–13,000 feet deep, high temperature and pressure
Marcellus Shale Play	Susquehanna River Basin, Ohio River Basin, Pennsylvania	Mostly dry gas, shale	Rapidly growing, diverse, area of significant public attention	5,000–7,000 feet deep, 100–500 feet thick, largest shale gas reserves in U.S.
North San Juan Basin	La Plata County, Colorado	Coal-bed methane	Colorado regulations, distinct risks due to CBM production	Fruitland formation, 550–4,000 feet deep
Upper Green River Basin	Jonah Field, Pinedale Anticline Wyoming	Mostly dry gas, tight sands	Active production, ozone nonattainment	Vertical wells, 8,000–11,000 feet deep in tight sands

This chapter also examines recent actions by local governments to ban, delay, or regulate hydraulic fracturing or gas development; responses to such actions by state courts and legislatures; and the implications of these developments for the industry's social license to operate in specific parts of the country.

Lastly, this chapter identifies several important examples where companies have adopted measures that go beyond compliance—namely, "green" completions, voluntary disclosure of chemicals used in hydraulic fracturing fluids, and reuse of produced and flowback waters. In some cases, these best practices have become the basis for new regulations (e.g., "green" completions). In others, they continue as voluntary actions that fill gaps or go beyond existing regulatory frameworks (e.g., reuse of produced and flowback waters).

The major conclusions that emerge from this analysis are as follows:

- Although there is a trend toward more regulation at all levels of governance, there has been a corresponding increase in regulatory fragmentation and differentiation at state and local levels. Better coordination and policy alignment among regulators can help to reduce risks of regulatory fragmentation including uncertainty, delays, gaps, and redundancies across jurisdictions. Improved communication and sharing of information between regulators at all levels of government and across jurisdictions—as well as increased transparency in the form of publicly reported and publicly available data from industry—will help ensure that regulations are coordinated and tailored to specific geographic and geologic characteristics. Appropriately designed regulations that reflect local conditions such as gas composition and geology reduce environmental risks and ensure more efficient resource recovery.
- Compliance monitoring and enforcement actions vary significantly across states, with significant implications for the efficacy of regulations, as well as public confidence in the ability of state regulators to ensure that development proceeds safely. Public disclosure of violations, enforcement actions, and company compliance would bring greater transparency and accountability to an industry that, by its nature, poses unique compliance and enforcement challenges due to the disparate and often remote location of facilities and its rapid development in recent years. It would also provide an opportunity to highlight the compliance records of leading companies that have demonstrated a commitment to safe natural gas production.
- There is a significant range in the environmental performance of operators in the industry, with some operators performing at a level that goes beyond existing regulations and other operators falling short. Ongoing consolidation in the industry could lead to more widespread adoption of best practices across the industry. However, additional implementation of beyond-compliance measures is unlikely to lead to less regulation given limited public acceptance of the concept of self-regulation in the industry. In some instances, the implementation of best practices may serve as the foundation for future regulation (Efstathiou 2012), which, in turn, could serve to level the playing field among producers and may help restore public trust in areas of the country where unconventional gas development has been controversial.
- There is a need for basin- and company-specific data to analyze the extent to which implementing beyond-compliance measures or additional regulation will affect the cost of producing natural gas and, by extension, the supply of gas to the electric power sector.[48] This study was not able to collect such data (see Chapter 4), but this will be a focus of a potential follow-up study.
- Notwithstanding the challenges of regulatory fragmentation, different state and local approaches to regulating unconventional natural gas development provide important opportunities for learning and innovation regarding substantive rules, the role of best practices, and process. Colorado, for example, recently implemented landmark legislation

[48] A recent report estimates that the application of 22 "Golden Rules" for shale gas development could add about 7% to the overall drilling and completion costs on a per well basis (IEA 2012). Assuming today's costs and prices are roughly equivalent, 7% added costs in the U.S. would amount to roughly an additional $0.25/MMBtu produced.

with the support of multiple constituencies, including the natural gas industry and environmental groups, that resulted in a dramatic shift in the state's electric power sector away from coal toward greater use of natural gas and renewable energy (see Chapter 1 for a discussion of the potential climate benefits associated with using natural gas as opposed to coal as a feedstock for electricity generation). This could not have happened absent an initial effort to revise the state's oil and gas laws. New York's decision to undertake a detailed and extensive study of the impacts associated with high-volume hydraulic fracturing has led to development of some of the most comprehensive rules in the country. It remains to be seen whether, if adopted, they alleviate public concerns regarding the risks associated with unconventional gas development .

2.2 Federal Legal Framework

The major federal environmental laws provide the overarching framework for regulating many of the environmental impacts associated with unconventional natural gas development. Some of these laws, however, contain explicit exemptions or definitional exclusions for natural gas development, resulting in a significant role for state regulation in key areas such as waste management, disclosure of chemicals used in hydraulic fracturing and releases, and well construction standards other than for underground-injection disposal wells. This section analyzes the federal regulatory framework governing air, water, and waste issues associated with unconventional gas development. It focuses on the scope of federal regulation, the extent to which state law fills any gaps left open by the federal regulatory scheme, recent legislative proposals and rule-makings, key trends, and the implications of a changing federal regulatory framework for future development.

2.2.1 Overview and Key Trends

Federal laws governing the air, water, and waste impacts associated with the production of unconventional natural gas vary in terms of scope. EPA has broad authority to regulate emissions of air pollutants, including GHGs, direct and indirect discharges of wastewater from point sources, and the injection of produced water into underground injection wells for disposal.[49] The federal government, primarily through the U.S. Department of the Interior, also has authority over the development of natural gas on federal and tribal lands. Federal oversight over the management of hazardous and solid wastes, reporting and disclosure requirements of toxic or hazardous releases, and the process of hydraulic fracturing itself is much more limited—and, in some cases, it is entirely absent given specific exemptions and definitional exclusions under certain federal laws such as the Resource Recovery and Conservation Act; the Comprehensive Environmental Response, Compensation and Liability Act; and the Safe Drinking Water Act.

Some federal exemptions have been the focus of proposed legislation in past and current Congresses,[50] and efforts to repeal or narrow these exemptions are likely to continue. Congress also recently requested that EPA conduct a study evaluating the potential impacts of hydraulic fracturing on drinking water (EPA 2011e). Depending on the results of this study, the first of

[49] An exception to this is section 112(n)(4) of the Clean Air Act, which contains prohibitions on the aggregation of hazardous air pollutant emissions from certain gas wells and other equipment that constrain regulation of such sources (42 U.S.C. § 7412(n)(4)).
[50] See, for example, The Fracturing Responsibility and Awareness Act of 2011, H.R. 1084.

which are due out sometime in 2012 with additional results in 2014, EPA may assume a more active role in regulating hydraulic fracturing—including reconsidering its determination that certain natural gas wastes are not hazardous, and recommending changes to the statutory framework that applies to the process of hydraulic fracturing. In the meantime, the states continue to play an important role in regulating various aspects of hydraulic fracturing. The extent to which states have filled gaps left open by federal regulation is discussed in Section 2.3.

The trend at the federal level is toward more regulation. As discussed in more detail below, a number of federal rules related to gas development have been finalized, proposed, or announced recently in response to increased development, and there have been repeated calls for new legislation. Taken together, these efforts indicate a growing interest in hydraulic fracturing and unconventional gas development at the federal level and the likelihood of additional federal regulation, and possibly legislation regarding the removal of certain exemptions in existing statutes, as has been proposed in the past.

2.2.2 Hydraulic Fracturing

The process of hydraulic fracturing, other than when diesel fuel is used, is expressly excluded from federal regulation under the Safe Drinking Water Act's Underground Injection Control program.[51] Were hydraulic fracturing not specifically excluded from the definition of *underground injection*, the natural gas industry would be required to comply with certain federal well construction, operation, and closure requirements, as well as disclosure requirements. This has been, and likely will continue to be, a source of controversy because numerous bills were introduced in 2009, 2010, and 2011 to bring the process of hydraulic fracturing within EPA's control (Martin et al. 2010).[52] Although prior attempts have all been unsuccessful, it is likely that similar legislation will be introduced in the future (Hammer and VanBriesen 2012). Additional pressure for greater federal regulation could also come as a result of EPA's hydraulic fracturing study if it concludes that the process of injecting fluids underground during hydraulic fracturing increases the risk of groundwater contamination.[53]

EPA recently published draft guidance governing the use of diesel in hydraulic fracturing fluids that includes requirements for diesel fuels used for hydraulic fracturing wells, technical recommendations for permitting, and a description of diesel fuels for EPA underground injection control permitting (EPA 2012b). As proposed, this guidance only applies where the EPA is the permitting authority. States with primacy over the Underground Injection Control program, which include Texas, Louisiana, and Wyoming, are not required to follow the guidance (Figure 11).

[51] 42 U.S.C. § 300h(d)(1)(B)(ii) (2005).
[52] The most recent efforts being The Fracturing Responsibility and Awareness Act of 2011, H.R. 1084.
[53] An area of ongoing controversy and debate is whether or not the process of hydraulic fracturing poses a greater risk of subsurface water contamination than other aspects of development that are common to all types of oil and gas production such as surface spills, impoundment failures, and faulty well construction (Groat and Grimshaw 2012; Hammer and VanBriesen 2012; Jones 2011).

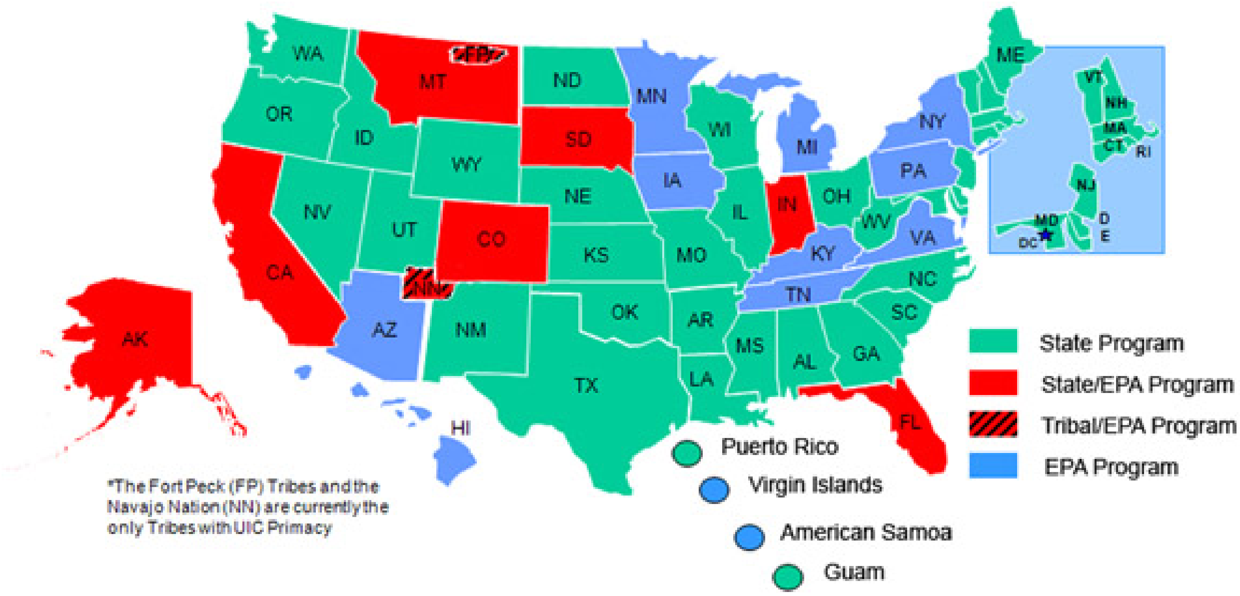

Figure 11. EPA map of Underground Injection Control Program Primacy[54]

Given the limited federal role in this area, states are the primary regulators of well construction standards that apply to the process of hydraulic fracturing (see Section 2.3.3 below).[55] However, with respect to natural gas development on federal lands, the Bureau of Land Management (BLM) recently proposed a rule that would require the use of cement bond logs on surface casing and mechanical integrity testing prior to hydraulic fracturing to improve well integrity (BLM 2012). Both EPA's proposed diesel fuel guidance and BLM's proposed well construction standards help to provide greater regulatory certainty to the production of natural gas. However, state regulations remain central given the limited applicability of the EPA guidance and BLM standards.

2.2.3 Water Quality

As reported in various news media, for the public, some of the most prominent environmental concerns associated with unconventional gas development that have emerged are adverse impacts to groundwater and surface water resources. The major federal statutes protecting water quality—the Clean Water Act and the Safe Drinking Water Act—apply to various aspects of unconventional gas development, with different approaches and experiences in different parts of the country.

The Clean Water Act prohibits the unauthorized discharge of wastewater into the surface waters of the United States from point sources. Discharges may be authorized by permits issued under the National Pollutant Discharge Elimination System, whose permits require industry-specific, technology-based limits and water-quality-based effluent limitations. The latter vary depending

[54] EPA, "UIC Program Primacy," http://water.epa.gov/type/groundwater/uic/Primacy.cfm.
[55] Well integrity is essential not only to reduce risks associated with hydraulic fracturing, but also, with the entire universe of down-hole activities (i.e., wells that are not hydraulically fractured also pose a risk to surface and subsurface water sources if not properly cased, cemented, and monitored).

on local conditions because they are tailored to protect specific designated uses of surface waters.

EPA has established two national effluent limitation guidelines that apply to unconventional gas wells. The first completely prohibits the discharge into navigable waters of natural gas wastewater pollutants, such as produced water, drilling muds, or drill cuttings from any source associated with oil and gas production, field exploration, drilling, well completion, or well treatment, located east of the 98th meridian. [56] The second guideline applies to operators west of the 98th meridian and allows the discharge of produced water only if it may be used beneficially for agricultural or wildlife propagation.[57]

Indirect discharges to publicly owned treatment works (POTWs) and discharges from centralized waste treatment facilities (CWTs) are also subject to the Clean Water Act framework. However, EPA has not promulgated pretreatment standards that apply to the discharge of shale and coal-bed methane (CBM) wastewater to POTWs, leaving a gap in the federal framework that has been the source of considerable controversy. Discharges from CWTs are subject to federal technology-based standards, although these standards do not contain limits for all of the pollutants contained in natural gas wastewater—in particular, bromide or total dissolved solids. [58]

EPA's decision under the CWA to prohibit direct discharges of drilling wastewater to surface waters in states east of the 98th meridian, combined with limited injection well capacity in that part of the country (see Chapter 4, discussing the fact that Pennsylvania has only eight Class II underground disposal wells), has resulted in increased use of indirect discharges to POTWs and CWTs. Many POTWs, however, are not designed or permitted to handle the volumes and types of wastewater produced from the booming shale gas industry (Urbina 2011). In Pennsylvania, insufficient treatment capacity for shale gas wastewater resulted in contamination of state waters—in particular, elevated levels of total dissolved solids, organic chemicals, and metals (EPA 2011c)—prompting the state to request operators to voluntarily cease sending shale gas wastewater to older POTWs and also resulting in new state limits for total dissolved solids and chlorides[59] (EPA 2011b).

EPA has announced its intent to develop pretreatment standards for discharges of CBM and shale wastewater in 2013 and 2014, respectively (EPA 2011a). These standards should bring certainty to this area, reduce the likelihood that treated wastewater discharges from POTWs will contaminate surface waters, and improve public confidence in the ability of natural gas development to be done safely. Depending on how these standards are set, they may also drive the development of technologies to recycle and reuse wastewater. If, for example, EPA adopted a "no discharge" or otherwise stringent limit, operators would need to rely more heavily on other

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[56] Onshore Subcategory Guidelines, 40 C.F.R. § 435.30 (2012). The 98th meridian runs through North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, and Texas. Direct discharges of produced water west of the 98th meridian are permitted provided the water does not exceed specified parameters for oil or grease and can be used for agricultural or wildlife propagation. *Id*. § 435.50.

[57] *Id*. § 435.50. Produced water has an effluent limitation of 35 mg/L of oil and grease. *Id.* § 435.52.

[58] See 33 U.S.C. § 1317 (2012); EPA, "National Recommended Water Quality Criteria," available at http://water.epa.gov/scitech/swguidance/standards/criteria/current/index.cfm.

[59] 25 Pa. Code § 95.10(b)(3)(iv)-(vi).

forms of wastewater disposal such as underground injection or recycling. In parts of the country, such as Pennsylvania, where underground injection wells are limited, a "no discharge" standard could result in significantly more recycling and reuse—especially if doing so is less costly than transporting wastewater out of state for injection.

As noted above, in addition to complying with national effluent limitation guidelines, POTWs and CWTs discharging wastewater must comply with numeric limits on certain pollutants designed to ensure that discharges do not impair the designated uses of surface water bodies. Although EPA has established guidance for water-quality criteria for some natural gas wastewater, it does not cover all pollutants contained in wastewater (Hammer and VanBriesen 2012).[60] Additional guidance from EPA would provide a certain degree of certainty and more uniform protection because states rely on EPA guidance when adopting water-quality criteria, and EPA retains authority to promulgate its own criteria if it determines a state has failed to adopt adequate standards of its own. Notably, EPA recently signaled its intent to update water-quality criteria for chloride, which is arguably outdated because it was established well before the recent shale gas boom (EPA 2011b).

2.2.4 Hazardous and Solid Wastes

2.2.4.1 Management of Waste

Subtitle C of the Resource Conservation and Recovery Act imposes stringent "cradle-to-grave" requirements that apply to the generation, transportation, treatment, storage, and disposal of hazardous waste.[61] Most of the wastes associated with natural gas drilling, however, are exempt from the Resource Conservation and Recovery Act's program for hazardous wastes. Specifically, drilling fluids, produced water, and other wastes "intrinsically related" to the production and development of natural gas are exempt from Subtitle C hazardous waste requirements.[62] As a result, management of these wastes is primarily a matter of state law. Non-exempt wastes, such as unused fracturing fluids, waste solvents, and used hydraulic fluids, are subject to the Resource Conservation and Recovery Act and may be covered under Subtitle C if they exhibit hazardous characteristics or are specifically listed as hazardous wastes. Exempt wastes not regulated as hazardous are subject to state rules because EPA has not promulgated regulations governing the management of oil and gas solid waste (NRLC 2012). Although this allows for regulation to be tailored to local geologic or hydrologic conditions, it also creates greater horizontal fragmentation, uncertainty, and the potential for inadequate state rules. See the discussion in Section 2.3.5.2 and Table 28 in Appendix C comparing state rules for produced water.

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[60] The current guideline only applies to certain pollutants such as chloride, oil and grease, suspended solids, turbidity, and nitrates. See EPA, "National Recommended Water Quality Criteria," available at http://water.epa.gov/scitech/swguidance/standards/criteria/current/index.cfm.

[61] 40 C.F.R. pt. 260 et seq. Specifically, generators must ensure and fully document that their hazardous waste is properly identified, managed, and treated prior to recycling and disposal. They must comply with requirements for training and emergency arrangements (including having an emergency coordinator and testing and maintaining emergency equipment) and must track the shipment and receipt of their waste. Additionally, a hazardous waste generator is limited in the amount of waste it can accumulate. A large-quantity hazardous waste generator (one that generates 1,000 kg or more of hazardous waste per month) must move all the waste it generates off site within 90 days; a small-quantity generator must move all its waste off site within 180 days. See EPA, Regulations Governing Hazardous Waste Generators, at III-41-47, http://www.epa.gov/osw/inforesources/pubs/orientat/rom33.pdf.

[62] In addition, EPA has determined that produced water injected for enhanced recovery is not waste subject to the Resource Conservation and Recovery Act and is therefore exempt from regulation under the statute. However, produced water stored in above-ground impoundments is subject to state law (EPA 2000).

Some observers have called for the federal regulation of natural gas waste as hazardous under Subtitle C of the Resource Conservation and Recovery Act (Hammer and VanBriesen 2012). EPA has not signaled its intent to reverse its decision regarding the management of natural gas waste; however, it remains a possibility, and may turn, in part, on the outcome of EPA's study on hydraulic fracturing.

2.2.4.2 Liability for Releases of Hazardous Substances

The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), also known as "Superfund," imposes strict liability for releases of hazardous substances on owners and operators of "facilities" (which include natural gas production sites), as well as arrangers and transporters of hazardous substances. The definition of *hazardous substance* under CERCLA, however, is limited in its application to crude oil, petroleum, and natural gas.[63] Specifically, petroleum and crude oil—as well as hazardous substances that are normally mixed with or added to crude oil or crude oil fractions during the refining process—are not considered hazardous substances under the so-called "petroleum exclusion."[64] Also excluded from the definition of hazardous substances are natural gas, natural gas liquids, liquefied natural gas, and synthetic gas usable for fuel.[65] Releases of other hazardous substances from natural gas drilling operations, such as hydraulic fracturing fluids containing hazardous chemicals, are subject to standard CERCLA liability. Thus, federal law provides for some potential CERCLA liability for natural gas operators, but the scope of such liability is narrow. Moreover, even though some states, such as Colorado, Texas, and Pennsylvania, have adopted their own environmental cleanup legislation, these states have all retained the federal definition of hazardous substances.[66]

2.2.4.3 Reporting of Hazardous or Toxic Chemical Releases

Federal law imposes few reporting requirements on operators of natural gas production facilities for the release of hazardous or toxic chemicals. Under CERCLA, operators must report releases of hazardous substances above reportable quantities, although the same definition of hazardous

[63] 42 U.S.C. § 9601(14).
[64] *Id*. Discharges of oil from certain production facilities may be subject to the Clean Water Act's Oil Pollution Prevention Program, which requires covered facilities to prepare and implement Spill Prevention Control and Countermeasures to prevent oil discharges (EPA 2000).
[65] *Id*. at § 9601(14).
[66] New York has a state law mirroring CERCLA, including a state Superfund to pay for site cleanup when no responsible party can be identified or the responsible party has inadequate funds for the cleanup. The state requires reporting and cleanup of petroleum spills within the state through its spill response program and its Brownfield and Superfund laws. New York's Brownfield regulations still exclude "natural gas, natural gas liquids, liquefied natural gas, synthetic gas usable for fuel, or mixtures of natural gas and such synthetic gas" from the definition of "hazardous waste" and "contaminant," thereby removing natural gas from the law's application. New York Department of Environmental Conservation, *Chemical and Petroleum Spills*, http://www.dec.ny.gov/chemical/8428.html; see also New York General Remedial Program Requirements, N .Y. Comp. Codes R. & Regs. title 6, § 375-1.2(w)(1). Pennsylvania operates within the CERCLA framework, but also has separate state legislation to fill in gaps in CERCLA. Pennsylvania Department of Environmental Protection, *Superfund*, http://www.portal.state.pa.us/portal/server.pt?open=514&objID=589587&mode=2. This state legislation retains the exclusion for natural gas and petroleum from the definition of "hazardous substance" and "hazardous waste." Pennsylvania Hazardous Sites Cleanup Act, 756 Act 1988–108, sec. 103 (definitions of "hazardous substance" and "hazardous waste"). Colorado has a statute on hazardous waste cleanup that essentially authorizes the State to cooperate with the federal government in the implementation of CERCLA. Colorado Hazardous Waste Cleanup Act, C.R.S. § 25-16-101. The Colorado statute adopts the CERCLA definition of hazardous substance, thereby excluding petroleum and natural gas. *Id*.

substance applies here as it does to the statute's liability scheme.[67] Oil and gas operators are not required to report annual releases of toxic chemicals under rules promulgated pursuant to the Emergency Planning and Community Right-to-Know Act's Toxics Release Inventory or to disclose the chemicals used in hydraulic fracturing to members of the public or regulators due to the exemption of hydraulic fracturing under the Safe Drinking Water Act.[68]

Natural gas operators are subject to requirements to report or disclose chemicals stored on-site, although these are limited. Owners and operators of storage facilities holding in excess of 10,000 pounds of any hazardous chemical must submit chemical inventory information to state and local emergency response and fire officials.[69] In addition, under the Emergency Planning and Community Right-to-Know Act and regulations promulgated pursuant to the Occupational Safety and Health Act, natural gas operators using products containing hazardous chemicals must maintain material safety data sheets on site, and must make them available to state and local emergency response and fire officials, subject to trade secret protection.[70]

States are increasingly filling the gap related to public disclosure of the chemicals used in hydraulic fracturing fluids. As discussed in more detail below, there is a clear trend toward public disclosure of all chemicals, not just those listed on material safety data sheets (Table 23 in Appendix C). This trend is evident at the state level and in the recently proposed BLM rule, which would require disclosure for production on federal and tribal lands (BLM 2012).

In terms of other reporting requirements, EPA has announced an intention to gather data on the aggregate amounts of exploration and production chemical substances and mixtures used in hydraulic fracturing. It is unclear to what extent these regulations will fill any of the gaps that remain in federal reporting requirements. But EPA has signaled an intent to avoid vertical fragmentation by framing its proposal as one that "would not duplicate, but instead complement, the well-by-well disclosure programs of states"(EPA 2011d).[71] In addition, states may adopt their own reporting requirements for releases.[72]

2.2.4.4 Disposal of Produced Water

As noted above, states primarily regulate waste disposal. One exception is the disposal of produced water into Class II underground injection wells, which is regulated by EPA's Underground Injection Control program, although states with primacy issue the actual permits.[73] Some states have recently raised concerns regarding the disposal of produced water into Class II wells, in response to evidence linking such disposal to earthquakes (Niquette 2011; Hammer and VanBriesen 2012). For example, nine earthquakes were recorded recently in Youngstown, Ohio,

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[67] 42 U.S.C. § 11004 (2012). EPA also requires operators to disclose "the source and analysis of the physical and chemical characteristics" of chemicals used in underground well stimulation permit applications (EPA 2008b).
[68] 42 U.S.C. § 11023(b) (2012) (EPA 2000; Wiseman 2010).
[69] 42 U.S.C. § 11022 (2012).
[70] *Id.*; 29 C.F.R. §1960.34(b)(6) (2012). Disclosure to the public of material safety data sheets is available upon written request.
[71] Letter from Stephen A. Owens, Assistant Administrator to Ms. Deborah Goldberg, Earthjustice re: TSCA Section 21 Petition Concerning Chemical Substances and Mixtures Used in Oil and Gas Exploration or Production, (Nov. 23, 2011), http://www.epa.gov/oppt/chemtest/pubs/EPA_Letter_to_Earthjustice_on_TSCA_Petition.pdf.
[72] See, for example, COGCC R. 906(b)(3) (requiring oil and gas producers to report spills that threaten to impact waters of the state).
[73] 40 C.F.R. § 144.6 (2010).

all of which were located within a half mile of an injection well, and all of which occurred within the first 11 months of injection of produced water into the well (Niquette 2011). Although scientists have yet to determine the cause of recent earthquakes, there have been instances in the past where injection wells used by other industries have been linked to earthquakes. (Holland 2011). This indicates that any causal relationship between underground injection of waste and seismic activity is not an impact unique to the natural gas industry. However, the volume of produced water associated with the significant increase in unconventional gas development across the country may place an increased strain on underground injection well capacity, especially in those areas where other disposal methods are less available. In addition to potentially causing earthquakes, underground injection of large amounts of produced water can increase the risk of subsurface contamination due to leaky wells.[74] Some suggest EPA should require the disposal of produced water into Class I, rather than Class II, wells because the former are subject to more rigorous standards on well construction, operation, and closure (Hammer and VanBriesen 2012). This will likely be an area of continuing public scrutiny and could be subject to additional state or federal regulation in the future.[75]

2.2.5 Air Quality

EPA has broad authority under the Clean Air Act to promulgate rules to reduce air pollution from natural gas sources. The most prominent air-quality issues associated with unconventional gas development include emissions of ozone precursors, VOCs and oxides of nitrogen, various hazardous air pollutants, and methane, all of which are subject to the basic Clean Air Act framework. Concentrated natural gas development has led to elevated ozone levels in rural parts of Wyoming and Utah where little other industrial activity occurs (Fruedenthal 2009; Streater 2010), and has also contributed to ozone pollution in more urban and industrial areas such as the Dallas Fort-Worth metropolitan area (Armendariz 2009). In 2012, the EPA responded to exceedances of the national health-based ambient air quality standards (i.e., National Ambient Air Quality Standards) for ozone in the Upper Green River basin by classifying the basin—for the first time—as in nonattainment with the 2008 8-hour National Ambient Air Quality Standard for ozone. [76] This listing could result in the state adopting more stringent rules to reduce emissions of VOCs and/or NO_x from natural gas sources in the basin to meet its Clean Air Act obligations.

Until recently, EPA has exercised its Clean Air Act authority with respect to natural gas production by focusing on a select number of natural gas production sources such as new and modified gas-processing plants, glycol dehydrators, crude oil and condensate storage vessels, and select engines used in the natural gas supply chain (e.g., engines used to power compressors). Most of these rules were implemented long before the unconventional natural gas boom occurred.

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[74] Personal conversation with Mark Williams, Professor of Geography and Fellow, INSTAAR, University of Colorado-Boulder, April 25, 2012.

[75] Notably, the Ohio Dept. of Natural Resources has enhanced Class II well permitting requirements, requiring seismic tests prior to construction of the well and ongoing monitoring, among other protections. Ohio Dept. of Natural Resources, Class II Disposal Well Reforms/Youngstown Seismic Activity Questions and Answers, http://ohiodnr.com/downloads/northstar/YoungstownFAQ.pdf.

[76] See EPA State Final Designations, April 2012 and May 2012, http://www.epa.gov/ozonedesignations/2008standards/state.htm.

In April 2012, however, EPA issued revised New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) (EPA 2012c)[77] that update existing standards and apply new requirements to previously unregulated sources. Specifically, EPA's new rules add requirements limiting VOCs and hazardous air pollutants emitted from completions and recompletions of hydraulically fractured natural gas wells (known as the "reduced emission completion" or "green completion" requirement), pneumatic devices, storage vessels, compressors, and "small" glycol dehydrators located at major sources of hazardous air pollution (EPA 2012c). Certain of these requirements result in the co-benefit of reducing methane because, in many cases, controlling VOCs also results in methane reductions (EPA 2012c). In addition, EPA updated standards and limits that apply to gas processing plants and large glycol dehydrators located at major sources of air pollution (EPA 2012c).

The revised NSPS and NESHAPS regulations provide a national floor that addresses unevenness in state air requirements. For example, EPA's new green completion requirements impose a level of uniformity across states with respect to control of ozone precursors and methane from unconventional natural gas development, as illustrated in Table 29, Appendix C, which compares green completion requirements. These new requirements implement one of the key recommendations of the SEAB, that EPA "adopt rigorous standards for new and existing sources of methane, air toxics, ozone precursors and other air pollutants from shale gas operations[.]" (SEAB 2011a, 2011b). Prior to EPA's adoption of the reduced emission completion requirement, many operators voluntarily used green completion practices to maximize resource recovery, illustrating how certain best management practices can serve as the foundation for future regulation (Efstathiou 2012, EPA 2012c).

In August 2012, EPA released a rule that requires capture or high-efficiency combustion of associated gas produced from crude oil wells in the Fort Berthold Indian Reservation in North Dakota.[78] The rule applies during well completions and re-completions, the separation phase of oil production, and during production. Specifically, the rule requires that operators control emissions of VOCs by 90% during well completions or re-completions or perform a reduced-emission completion, route all produced gas and gas emissions to a control device capable of at least a 90% control efficiency upon production, and, within 90 days of production, capture all associated gas or route it to a control device capable of 98% control efficiency.

In September 2012, natural gas producers will also begin reporting GHG emissions from facilities subject to EPA's Mandatory Greenhouse Gas Reporting rule. As required by that rule, natural gas facilities that emit 25,000 metric tons of CO_2e or more of GHGs will be required to report GHG emissions (EPA 2010). Operators have been granted a grace period to use less rigorous measurement practices initially, but the data collected will provide much greater certainty regarding actual methane leakage rates. Precise information regarding methane emissions from natural gas systems is essential to resolving discrepancies among life cycle assessments, such as those discussed in Chapter 1.

[77] U.S. E.P.A, Final Rule, "Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," http://www.epa.gov/airquality/oilandgas/pdfs/20120417finalrule.pdf.
[78] EPA, "Approval and Promulgation of Federal Implementation Plan for Oil and Natural Gas Well Production Facilities; Fort Berthold Indian Reservation (Mandan, Hidatsa, and Arikara Nations), ND" 77 Federal Register 48878 (August 15, 2012).

Despite EPA's broad authority to implement clean air measures, states retain significant room to regulate. States with delegated programs may implement standards more stringent than federal law, unless prohibited by state law from doing so. States retain authority to regulate sources and air pollutants not covered by existing federal rules, and states may also impose more stringent rules than federal to meet National Ambient Air Quality Standards for criteria pollutants.

2.3 State Statutory and Regulatory Frameworks

Against this backdrop of federal environmental regulation, state and local governments have adopted numerous laws and regulations governing unconventional gas development, with considerable variation across different states, especially regarding the handling of waste and wastewater, construction of wells other than underground injection disposal wells, and baseline water-monitoring requirements. States also have exclusive jurisdiction over water withdrawals, other than those occurring on federal lands,[79] and over various land-use controls such as setback requirements and zoning, some of which have been delegated to local governments. As discussed above, although a number of federal rules apply to protecting water and air resources, states also retain authority to develop more stringent standards and to regulate impacts or sources not covered by federal law. Prior to EPA's recent revisions of the NSPS and NESHAPS, some states—notably Colorado and Wyoming—adopted air regulations that went beyond then-existing federal standards [80] (WY DEQ 2010), whereas New York has proposed a number of regulations to protect water sources and ensure safer waste management that go beyond federal and other state rules. Some states have increased inspection capacity to respond to the rapid increase in unconventional gas development; however, there is considerable variation in state inspection capacities and enforcement approaches.

This section analyzes the state regulatory frameworks governing air, water, waste, and compliance and enforcement issues associated with unconventional gas development in Colorado, Wyoming, New York, Texas, Louisiana, and Pennsylvania. It focuses on the extent to which state law fills any gaps left open by the federal regulatory scheme, as well as on key trends, differences in the regulatory frameworks across the different basins, compliance monitoring, and enforcement capabilities and actions.

2.3.1 Overview and Key Trends

The wide variation in state approaches to the regulation of unconventional natural gas development reflects differences in resource characteristics (e.g., dry versus wet gas, deep shale versus shallow CBM), geology, and hydrology, as well as different experiences with oil and gas development and different approaches to and preferences for environmental protection. Across the country, states have responded to hydraulic fracturing in very different ways. Vermont, for example, recently enacted legislation banning hydraulic fracturing in the state.[81] New York, as noted, has imposed a temporary moratorium on drilling as it develops regulations.[82] Recently, the Cuomo administration announced that it will undertake a public health study of the potential impacts of hydraulic fracturing and re-start the rule-making process prior to issuing any new

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[79] See, for example, the proposed BLM rule, which requires operators to identify the source of water to be used in fracturing in order for the BLM to determine impacts and mitigation measures, if needed (BLM 2012).
[80] COGCC R. 805(b).
[81] H 464 (enacted May 16, 2012).
[82] 9 N.Y. Comp. Codes R. & Regs. tit. 9, § 7.41.

regulations.[83] A number of states (specifically Colorado, Wyoming, and Pennsylvania) have revised their oil and gas rules extensively—at least once, and in some cases, continue to do so—to respond to the uptick in unconventional resource development; Louisiana and Texas have engaged in much more limited revisions. New York, as noted above, is in the process of revising its regulations. Louisiana, Pennsylvania, and Colorado have all recently submitted their hydraulic fracturing rules to the State Review of Oil and Natural Gas Environmental Regulations for review, whereas Wyoming and Texas have not (and New York has not yet finalized its high-volume hydraulic fracturing regulations) (STRONGER, 2010; STRONGER 2011a; STRONGER 2011b). Pennsylvania and Louisiana significantly increased the number of oil and gas inspectors in response to increased development, whereas resources in other states appear quite limited. Data are limited and more research is needed, but there appears to be very little consistency in the ways that states record, respond to, and enforce against violations—including substantial ranges in penalties and the number of violations that result in enforcement actions. Areas highlighted as meriting additional attention from state regulators are improved transparency regarding compliance monitoring, company compliance histories, and enforcement actions.

Different regulatory approaches by states can lead to uncertainty, gaps, and/or redundancies in mitigating some of the more significant environmental risks associated with unconventional gas development and ensuring overall compliance. But they can also provide a source of policy innovation because different jurisdictions experiment with new approaches to regulating various aspects of shale gas development. An example is New York's proposal to require operators to document that, compared to available alternatives, chemical additives used in hydraulic fracturing fluids exhibit reduced aquatic toxicity and pose a lower potential risk to water resources and the environment.[84] For this reason, it is important that state regulators and policy makers share information and lessons learned with other states. National standards provide a baseline or floor in some areas, such as national effluent limitation guidelines for wastewater discharges and EPA's recent NSPS and National Emission Standards for Hazardous Air Pollutants. However, a permanent feature of the regulatory landscape appears to be the uneven and varied nature of state and local regulation and enforcement regarding most other aspects of shale gas development.

Despite the variety in specific state and local regulations and enforcement, some important trends are evident. All states reviewed here recently revised their oil and gas rules and/or laws to respond specifically to the increase in unconventional resource development. Colorado, New York, Wyoming, and Pennsylvania recently undertook extensive reviews and revisions of their laws and regulations that , in some cases, resulted in considerably more comprehensive—and in many instances, protective—rules than those in Louisiana and Texas. For example, Colorado and Wyoming have been leaders in rules to reduce emissions of ozone precursors, and New York and Pennsylvania are leaders in laws regarding measurement and public disclosure of water sources and waste. See Table 22, Appendix C, for a general description of revisions to state oil and gas laws.

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[83] Danny Hakim, "Shift by Cuomo on Gas Drilling Prompts Both Anger and Praise," *New York Times,* Sept. 30, 2012.
[84] N.Y. Comp. Codes R. & Regs. tit. 6, §560. 3.

There is a clear trend in all of the states studied toward greater transparency—such as mandatory public disclosure of chemicals used in hydraulic fracturing and the composition of wastewater, reporting of the amounts and sources of water used in hydraulic fracturing, and more rigorous well-construction standards, including notifications of hydraulic fracturing and well completions. A key recommendation of the SEAB Subcommittee (SEAB 2011a) was greater transparency, in the form of public disclosure of the chemicals, amounts, and sources of water used or produced during hydraulic fracturing, baseline water monitoring measurements, and reduction and measurement of air emissions. These activities have the potential to lead to better public understanding and acceptance of natural gas development.

All states covered in this study have added requirements that providers of fluids used in hydraulic fracturing and/or operators disclose the contents of most chemicals to the public. These requirements are in addition to, and go beyond, federal requirements that require operators to maintain material safety data sheets for certain hazardous chemicals stored on-site in threshold quantities, and to report releases of hazardous chemicals in threshold quantities.[85] In addition, all of the states covered in this study require operators to report the amount and, in most cases, the source of water used in hydraulic fracturing either to the public or state regulators.

Other areas of state regulation or interest include: baseline water-monitoring requirements; use of closed-loop drilling systems to contain waste, rather than open, earthen pits; reporting or reduction of emissions of air pollutants; standards to ensure well integrity; and more active involvement on the parts of local government over drilling activities.

State compliance monitoring and enforcement capacity varies considerably, although significant data limitations across the different states mean that any comparisons should be considered provisional. Based on available data, some states—notably Pennsylvania and Louisiana—recently increased state inspection capabilities to respond to increased development, whereas resources in other states appear quite limited. The methods that states use to track and report violations and enforcement actions also differ substantially—with some states, notably Pennsylvania, making violations and enforcement actions publicly available via online databases; other states, notably Colorado and Wyoming, have been criticized for a lack of transparency and limited public access to such information.[86]

Variation across states in substantive regulations, as well as compliance monitoring and enforcement capacity, can be explained by a number of factors. Some are legal, such as federal effluent limitation guidelines that differ across regions and state statutes limiting the amount of penalties that can be assessed for violations. Others reflect differences in local environmental conditions (e.g., elevated ozone levels in the Upper Green River basin and Denver metropolitan area, respectively, led Wyoming and Colorado to adopt air rules that went beyond then-existing federal requirements, forming the basis for some of EPA's new NSPS rules); geologic and hydro-geologic conditions (e.g., developing shallow CBM resources poses unique risks that deep shale does not)[87]; proximity of drilling to densely populated areas or sensitive environmental

[85] 42 U.S.C. § 11021-11022 (2006); 55 Fed. Reg. 30,632 (July 26, 1990).
[86] See, for example, Earthworks (2012b) and Soraghan (2011).
[87] See, for example, COGCC R. 608(b)(4).

areas (e.g., setback requirements and buffer zones)[88]; historical and contemporary experiences with oil and gas development; and preferences for environmental protection.

2.3.2 Water Acquisition

The regulation of water withdrawals is primarily a matter of state and local, rather than federal, law. The legal framework governing water rights differs from state to state, although there is some consistency along regional lines.[89] There is a clear trend toward requiring operators to identify the sources of water used, report the amount of water used in hydraulic fracturing, and provide for incentives to promote reuse of water used in hydraulic fracturing such as by recycling flowback waters or production fluids. All states require operators to report on the amount of water used for hydraulic fracturing, as does BLM's new proposed rule.[90] In addition, both New York and Pennsylvania require operators to provide for the reuse and recycling of flowback water or production fluids in water management plans or wastewater source reduction strategies. States also have begun to require minimum in-stream flow below points of water withdrawal and other measures to ensure that aquatic wildlife, water quality, and other water users will not be adversely affected.[91]

A handful of local governments also regulate some aspects of water acquisition. For example, Archuleta County, Colorado, requires operators in the North San Juan basin to submit a water management plan that includes a plan for disposal or reuse, projected water use, identification of the water source, and water availability (Archuleta 2010). The City of Fort Worth, Texas, requires operators to describe the water source proposed to be used for drilling in application for permits to drill.[92] As unconventional gas development expands in various parts of the country, it seems likely that more local governments will seek to get involved in regulating aspects of water acquisition.

For more information related to state and local regulation of water withdrawals, see Table 24, Appendix C, Water Acquisition Requirements.

2.3.3 Hydraulic Fracturing and Well Construction Standards

State well-construction standards vary considerably, which to a certain extent can be explained by differences in local geology. However, certain safeguards do not depend on differences in local conditions. Standards that have been recommended to increase well integrity include the use of state-of-the-art cement bond logs, pressure testing of casing, monitoring and recording bradenhead annulus pressure, and assurances that surface casing is run below all known underground aquifers to reduce the risk of drinking water contamination from fluid or gas

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[88] See, for example, setback requirements in the Barnett Shale and New York's proposed buffer zones to protect sources of drinking water, Appendix C.

[89] The two most common doctrines governing water rights are the prior appropriation and riparian doctrines. The prior appropriation doctrine provides rights to continued use of water to those who first put water to beneficial use and is the predominant regime in most of the West (CDWR 2012; Groat and Grimshaw 2012). In a riparian water rights system, water rights are tied to the ownership of land adjacent to water resources.

[90] DOI, Bureau of Land Management, Proposed Rule "Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands", May 4, 2012, http://www.doi.gov/news/pressreleases/loader.cfm?csModule=security/getfile&pageid=293916.

[91] See, e.g., 58 Penn. Stat. § 3211(m)(2).

[92] Fort Worth, Tex., Ord. No. 18449-02-2009.

migration (SEAB 2011b). Of the states reviewed, only Colorado and Louisiana require the use of cement bond logs.[93] New York has proposed to require the use of cement bond logs. All states except Wyoming require some kind of pressure testing of casing, although the specifics vary regarding the testing and circumstances requiring testing. Colorado is the only state that requires monitoring of annulus pressure with bradenhead (Texas requires all wells to be equipped with bradenhead, but only requires a pressure test in certain instances). All states require surface casing to be set below known aquifers, although the specific requirements vary. For specific requirements, see Table 25 in Appendix C.

2.3.4 Baseline Water-Quality Monitoring

Requiring operators to conduct baseline monitoring of wells or water resources near gas operations is an important objective for all stakeholders because it results in science-based measurement data that can be used to identify whether or not well activities cause contamination. For example, in Pennsylvania, operators who conduct pre- and post-baseline water monitoring of nearby water sources can overcome a rebuttable presumption that a well operator is responsible for pollution of nearby water resources if the monitoring demonstrates that constituents found in the sampled water sources did not come from the well operator's activities.[94] In Colorado, the Colorado Oil and Gas Association instituted a voluntary baseline monitoring program, with results being submitted to the Colorado Oil and Gas Conservation Commission (COGCC), provided landowner consent.[95] Colorado requires baseline water testing in the North San Juan basin (as well as other parts of the state), in limited circumstances to protect sources of drinking water, resources located near CBM wells, and in the Greater Wattenberg Area.[96] New York has proposed to require operators to make reasonable attempts to sample and test all residential water wells within 1,000 feet of a well pad prior to commencing drilling. If no well is located within 1,000 feet, or the surface owner denies permission, then the operator must sample all wells within a 2,000-foot radius. Monitoring continues at specified intervals as determined by the U.S. Department of Environmental Conservation.[97] For more information related to state baseline monitoring requirements, see Table 26, Appendix C, Baseline Monitoring Requirements.

2.3.5 Storage and Management of Wastes

2.3.5.1 Waste Storage

As noted above, waste storage is largely a matter of state and local law. The onsite storage of waste—such as produced and flowback water, drill cuttings, and fluids—is usually restricted to either storage tanks or open lined or unlined pits. Open pits pose a number of risks, including

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[93] We do not include where state regulations refer to logs generally, as opposed to using the specific terminology "cement bond logs."

[94] 58 Pa. Cons. Stat. § 3218. In those instances where an operator is deemed responsible for contaminating or diminishing a private or public water source, he or she must restore or replace the water with an alternate source.

[95] Colorado Oil & Gas Association, "Colorado Oil & Gas Association Voluntary Baseline Groundwater Quality Sampling Program," http://www.coga.org/index.php/BaselineWaterSampling.

[96] Colorado requires baseline sampling of surface waters located downstream of drilling operations conducted near surface waters intended for drinking water and baseline sampling of water wells located near CBM wells. COGCC R. 317.b (2012). The state also recently added a statewide requirement that operators provide notice to surface and adjacent landowners, which must include instructions for the collection baseline water samples. COGCC R. 305.e.1.A (2012). Operators drilling in the Greater Wattenberg Area must also conduct limited baseline water sampling prior to drilling. COGCC R. 318A.

[97] Proposed N.Y. Comp. Codes R. & Regs. tit 6, § 560.5(d).

threats of drowning to migratory birds and wildlife, air pollution caused by the volatilization of hazardous or organic compounds, and soil and water contamination posed by overflowing pits or liner failures (Earthworks 2012, NM OCD 2008). According to the Ground Water Protection Council, "The containment of fluids within a pit is the most critical element in the prevention of shallow ground water contamination" (GWPC 2009). This study did not perform a comprehensive analysis of state pit requirements; however, a preliminary review revealed significant variation among state pit rules in terms of liner, monitoring, fencing, and other construction and operation requirements, which is complicated somewhat by the use of inconsistent nomenclature for pit types.

An alternative to the use of pits is the use of closed-loop or "pitless" drilling systems that require the storage of fluids in tanks, preferably closed tanks, rather than open pits. Closed-loop drilling reduces many of the risks associated with open pits (Earthworks 2012). Closed-loop drilling also "allows for enhanced monitoring of fluid levels and characteristics which allows for more efficient use of drilling fluids, reduces waste, encourages recycling, and reduces potential liability associated with waste management and reduces site closure costs"[98] (TRRC 2012). New York has proposed to require closed-loop drilling for drilling fluids and cuttings associated with high-volume hydraulic fracturing operations. Colorado, Pennsylvania, Wyoming, and Fort Worth (Texas), require the practice in certain situations, such as where drilling occurs in sensitive areas where there is a heightened risk of water contamination from pit failure or the implications of contamination are more severe if contamination does occur. A recent bill introduced in Colorado would have required enhanced use of this practice statewide.[99] BLM's proposed rule for development on public and tribal lands provides for the use of either closed-loop systems or pits (BLM 2012). For a comparison of state and local closed-loop drilling requirements, see Table 27, Appendix C, Closed-Loop or Pitless Drilling Requirements.

2.3.5.2 Produced Water Disposal

State requirements regarding the disposal of produced water also vary considerably. Some of this variation can be explained by local conditions, such as the scarcity of underground injection wells in Pennsylvania, as noted above. However, disparate regulatory requirements also contribute to state-by-state variation.

In general, natural gas operators have a variety of options for disposing of wastewater. These include discharging wastewater directly to surface waters, sending the waste to treatment facilities such as POTWs or CWTs authorized to discharge, disposal via underground injection well, reuse for further hydraulic fracturing, disposal into evaporation ponds or impoundments, or disposal via land application. However, legal and practical constraints can limit some of these options.

Of the states reviewed, Colorado, Wyoming, and Texas allow for direct discharges only in specified circumstances (e.g., if produced water meets national effluent limitation guidelines for agricultural or wildlife propagation). State requirements vary considerably with respect to indirect discharges to POTWs or CWT facilities. All of the states studied except New York allow for disposal or storage of produced water in evaporation or open pits, subject to specific

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[98] NY SGEIS, § 7.1.7.4.
[99] SB 12-107 (introduced January 31, 2012).

circumstances where closed-loop systems are required. Similarly, all states except New York and Texas allow for produced water to be disposed of via land application, such as road-spreading or land farming, but the specific requirements and limits for doing so vary considerably. New York has proposed to require operators to demonstrate that all flowback water and production brine will be treated, recycled, or otherwise properly disposed of over the projected life of the well,[100] and also, that operators prepare a waste tracking form for flowback and production brine similar to what is required for medical waste.[101] Operators in Pennsylvania must prepare a wastewater source reduction strategy identifying the methods and procedures operators will use to maximize recycling and reuse of flowback or production fluids, and most states are increasingly encouraging reuse and recycling. Additional requirements to incent or require recycling and reuse of produced and flowback are likely given the heightened interest in reducing the risk of contamination posed by other disposal methods, and reducing impacts to freshwater resources associated with withdrawals. See Table 28, Appendix C, Produced Water Disposal, for specific state disposal requirements for produced water.

2.3.6 Air Quality

As discussed above, EPA and the states exercise joint authority over standards to limit or report amounts of air pollution from unconventional gas activities.

State regulation of air contaminants varies significantly, with Colorado and Wyoming containing some of the most comprehensive and rigorous requirements to reduce emissions statewide and in areas home to significant drilling activity. Some of Colorado's and Wyoming's air rules have been driven by exceedances of the national ambient air-quality standards for ozone. For example, Wyoming adopted more stringent requirements to reduce VOCs from natural gas operations in the Upper Green River basin in response to elevated levels of ozone in the winter, as did Colorado in response to violations of national ambient air-quality standards for ozone in parts of the Denver-Julesburg Basin in the Denver Metropolitan Area. Attainment of national ambient air-quality standards (i.e., National Ambient Air Quality Standards) is determined at regional and local levels (so-called "air quality management regions"); also, states have flexibility under the Clean Air Act in developing state implementation plans under the National Ambient Air Quality Standards program. Therefore, state air pollution requirements and controls vary considerably.

In addition to meeting baseline federal requirements, areas that fail to meet—or are at risk of failing to meet—national ambient air-quality standards may adopt additional measures beyond those that apply statewide in order to improve air quality. Indeed, many of the standards recently adopted by EPA in its recent NSPS—such as those that apply to completions and re-completions of hydraulically fractured wells, storage vessels, and pneumatic devices—are similar to those already required in the Upper Green River basin in Wyoming and in Colorado (WY DEQ 2010, CDPHE 2012, COGCC 2008).[102] A different situation exists for the Barnett Shale, also in an area that fails to meet national ambient air-quality standards for ozone, where the state imposes few limits on the emissions of VOCs and hazardous air pollutants; here, EPA's new rules will add a number of requirements. See Table 29, Appendix C, for a comparison of how EPA's new

[100] Proposed N.Y. Comp. Codes R. & Regs. tit 6, § 750-3.12.
[101] NY SGEIS, § 7.1.7.1.
[102] See also COGCC R. 805.

reduced-emission completion requirement (or "green completion") compares with existing requirements in the basins reviewed.[103]

Despite EPA's enhanced role in regulating air pollution, states retain substantial discretion to regulate uncovered sources or pollutants, or, where permitted under state law, adopt more stringent rules and/or require additional reporting. For example, Pennsylvania recently added a requirement that natural gas operators report annually amounts of air pollutants.[104] New York has also proposed additional clean-air measures, including a requirement that natural gas operators submit plans to reduce GHG emissions.[105] State requirements vary considerably related to the amount of associated natural gas that operators may flare or vent during production. As production increasingly shifts toward liquids and oil-rich formations, this issue is likely to be an area of continuing policy focus because EPA's reduced-emission completion requirement does not apply to associated gas emitted during the production phase of oil wells.[106] EPA's recent Fort Berthold Indian Reservation rule provides one example of how regulators, going forward, may address the problem of associated gas emissions.

A number of recent air studies and reports have raised questions related to the sufficiency of current air regulations to protect the health of local communities from hazardous air pollutants and reduce fugitive and vented methane emissions (McKenzie et al. 2012; Petron 2012). As the industry expands, especially into more densely populated areas, concerns regarding air quality and GHG emissions will likely persist and receive ongoing regulatory attention.

2.3.7 Compliance Monitoring and Enforcement

Compliance is essential if regulations are to serve their purpose of mitigating environmental risks. Significant challenges for compliance monitoring occur due to the unique nature of the unconventional natural gas industry, characterized by dispersed and often remotely located facilities controlled by numerous operators whose practices can vary significantly. On top of this, regulators face a rapidly changing industry as development, technologies, and practices continue to expand in scale and scope.

A number of reports that have addressed the adequacy of state compliance monitoring and enforcement capabilities conclude that state inspection and enforcement capacity varies significantly, as do state processes for recording and disseminating compliance histories to the public (Groat and Grimshaw 2012; Earthworks 2012b; Soraghan 2011). For example, as Table 5 illustrates, Colorado and Wyoming have 15 and 12 inspectors, respectively, dedicated to oil and gas facilities (Earthworks 2012b; Groat and Grimshaw 2012). Pennsylvania, by comparison, quadrupled its enforcement staff in 2010, resulting in 193 enforcement personnel, 65 of whom are inspectors (Earthworks 2012b). Similarly, Texas has 125 inspectors while Louisiana has 38 (Groat and Grimshaw 2012, LDNR 2011). Data for New York were not identified.

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[103] Texas air rules are not comparable to EPA's recent rules in overall scope or rigor, with the exception of Fort Worth's "green completion" requirement. See Appendix C for green completion requirements.
[104] Act 13.
[105] NY SGEIS, § 7.6.8.
[106] For a discussion of this issue, see Clifford Kraus, *New York Times*, "In North Dakota, Flames of Wasted Gas Light the Prairie" (September 28, 2011).

As illustrated in Table 5, the number of inspections performed in each state varied considerably as well, although the data demonstrate a correlation between the number of inspectors and number of onsite inspections. Adequate inspection capability is critical to carry out the SEAB recommendation that "regulation of shale gas development should include inspections at safety-critical stages of well construction and hydraulic fracturing" (SEAB 2011a).

Table 5. Compliance Monitoring and Enforcement Capabilities[107]

State	Inspectors (2010–2011)	Field Inspections (2010–2011)	Total Violations (2009–2011)	Percent of total Violations that are Procedural	Percent of Violations that Result in Enforcement[108]
CO	15[109]	16,228[110]	N/A	N/A	N/A
LA	38[111]	363	158	60	70
PA	65[112]	298	2,280	22.4	N/A
TX	125	N/A	35[113]	72[114]	20
WY	12	2	N/A	N/A	N/A

Research conducted by the University of Texas identified significant variation among states in terms of the types of violations found (e.g., pit and tank construction and maintenance are the most common violations in Louisiana, whereas permitting violations are most common in Texas). Despite the variation in violations, it appears that most violations identified are minor or procedural violations. Note, however, that this does not necessarily mean that most environmental impacts associated with gas development are minor, nor that companies comply with more "serious" requirements at higher rates. A number of factors affect the types of violations that inspectors identify, such as the visibility of violations (e.g., special equipment is needed to detect and measure natural gas leaks from equipment), state inspector capacity to respond to complaints or conduct investigations, and types of complaints reported (Groat and Grimshaw 2012).

Enforcement varies considerably among states, as well. Table 5 illustrates that the percent of violations leading to enforcement actions differed significantly among states where data are available (e.g., 70% of violations noted resulted in enforcement actions in Louisiana compared to only 20% in Texas) (Groat and Grimshaw 2012; Soraghan 2011). Penalties also vary significantly across jurisdictions, due in part to statutory constraints limiting the amount of penalties a state may assess for a given violation (e.g., the maximum fine for a violation in Colorado is $1,000 per day, whereas enforcement authorities in Pennsylvania and Texas can issue fines of $5,000 and $10,000 per day, respectively) (Earthworks 2012b). Some have questioned whether monetary penalties are sufficient to deter non-compliance given the

[107] Data taken from Groat and Grimshaw (2012), unless otherwise noted.
[108] Soraghan 2011.
[109] Earthworks 2012b.
[110] *Id*.
[111] LDNR 2011.
[112] Earthworks, 2012b.
[113] See Chapter 4.
[114] These are for 2008–2011, rather than 2009–2011.

resources of some companies (Earthworks 2012; Soraghan 2011). Others posit that orders to cease production may be more likely to lead to compliance (Soraghan 2011).

Lastly, public dissemination regarding violations, enforcement actions, and company compliance histories also varies across states. Of the states reviewed, only Pennsylvania maintains a publicly searchable database of violations and enforcement actions. More complete and publicly available data on the compliance histories of companies are needed to understand the effectiveness of compliance and rules, as is more transparency and consistency in the ways that states record and report violations and impose penalties (SEAB 2011a). As with regulations themselves, unevenness in state compliance monitoring and enforcement capacity can lead to additional uncertainty and gaps as well as delay, because public mistrust of industry and regulators can undermine the industry's social license to operate, resulting in bans or moratoria on drilling.

2.3.8 Summary of State Statutory and Regulatory Framework

States are the primary regulators, inspectors, and enforcers of most impacts associated with unconventional natural gas development. Regulatory requirements, compliance monitoring, and enforcement capabilities vary across states. Some of this variation is reduced by the recent trend toward consistency in requirements related to the public disclosure of fluids and the amount and sources of water used in hydraulic fracturing. Additional regulation is likely in the area of well integrity standards—specifically, greater adoption of requirements to ensure adequate casing and cement jobs such as cement bond logs and pressure testing of casing. In addition, in light of continued public concern regarding adverse air, water, and waste impacts associated with unconventional gas development, states are likely to adopt regulations requiring baseline water-monitoring requirements, air-quality rules, and provisions that encourage or require greater reuse of produced and flowback waters. Some states may need to increase their inspection and enforcement resources to ensure that rules are being followed. Processes that provide greater transparency regarding state methods for identifying violations and bringing enforcement actions would help to improve public understanding of the extent to which additional resources are needed. Additional accountability and public trust are likely to result from self-reporting mechanisms that are publicly available, such as a joint industry non-governmental organization database on company compliance records (see SEAB 2011a).

2.4 Local Regulation and Social License to Operate

Across the country, communities have responded to the increased development of unconventional natural gas with mixed reactions. In half of the states reviewed for this study (Colorado, New York, and Pennsylvania), legislation has recently been proposed or enacted to limit the power of local governments to regulate unconventional gas development, or to make such local authority explicit (see Figure 12). In these states, 30 local governments have banned hydraulic fracturing or oil and gas development altogether, and an additional 73 have issued temporary moratoria pending review and potential revision of local land-use or other ordinances.[115] This section examines three different approaches to the issue of local authority,

[115] A handful of states have also banned or issued moratoria. In addition to New York, New Jersey (see A 3653 (introduced Jan. 6, 2011, http://www.njleg.state.nj.us/2010/Bills/A4000/3653_R1.HTM), and Maryland (see The Marcellus Shale Safe Drilling Act of 2011 H.B. 852 (effective June 1, 2011, http://mlis.state.md.us/2011rs/fnotes/bil_0002/hb0852.pdf) instituted temporary moratoriums on hydraulic fracturing; Vermont recently banned the practice (see H. 464 [enacted May 16, 2012]).

and provides an example of one set of requirements—setback requirements—intended to protect local communities and sensitive resources from adverse drilling impacts to illustrate differing approaches across and among states.

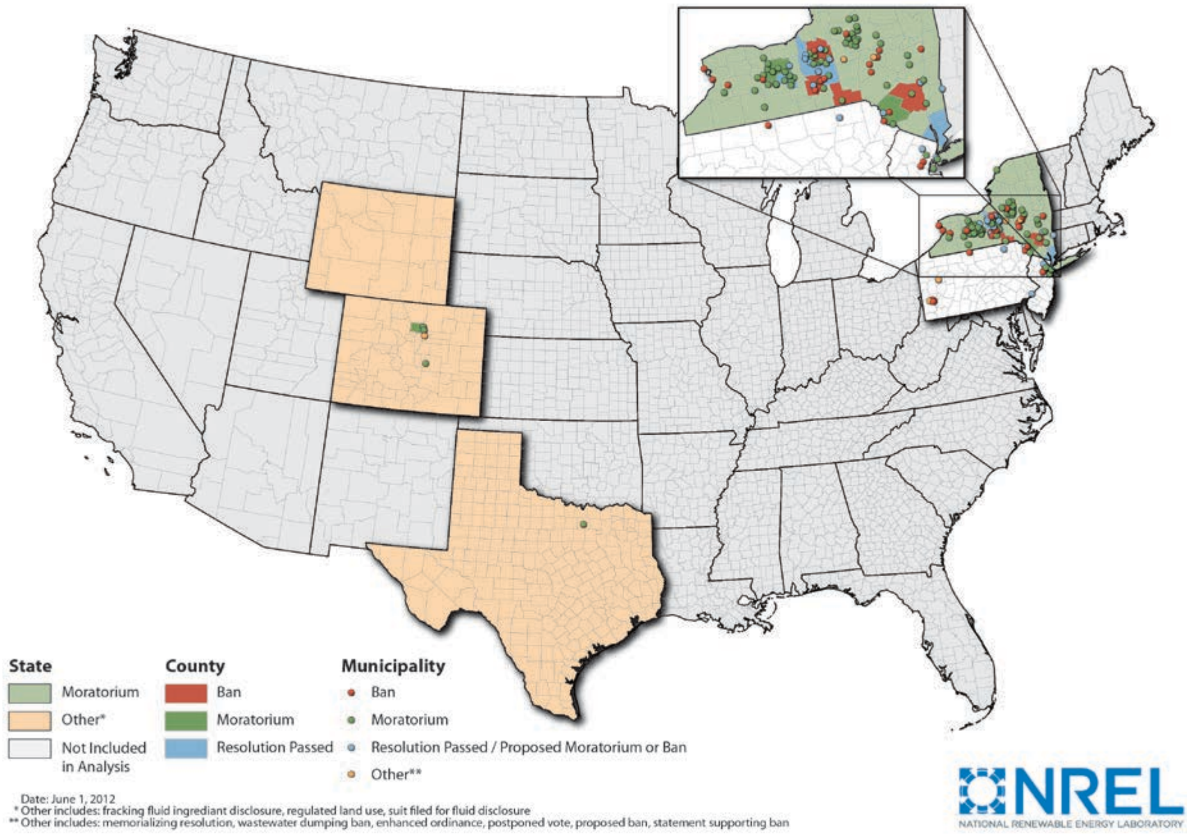

Figure 12. Variation in the rules for six states of rules covering natural gas fracking

States grappling with the issue of local control have adopted very different postures. At one end of the spectrum, Pennsylvania recently enacted legislation that places virtually all control over natural gas development in the hands of the state government.[116] This law, which went into effect April 16, 2012, elicited significant public opposition (Robinson 2012a; Robinson 2012b). A state court judge recently overturned those portions of the law restricting local governments from regulating oil and gas development on the basis that they unconstitutionally violate the substantive due process rights of local governments to enact zoning ordinances that protect the interests of neighboring property owners and neighborhood characteristics (Pellegrini 2012).

[116] Act 13 supersedes all local ordinances purporting to regulate oil and gas operations, other than those adopted pursuant to the Pennsylvania municipalities and planning code and Flood Plain Management Act and provides that "all local ordinances regulating oil and gas operations shall allow for the reasonable development of oil and gas resources." Municipalities must allow "oil and gas operations, other than activities at impoundment areas, compressor stations and processing plants as a permitted use in all zoning districts." The Act allows for the location of well pads within 300 feet of existing buildings, unless the wellhead is less than 500 feet from any existing building. Under the Act, counties may require oil and gas operators to pay impact fees ranging from $40,000 to $60,000 for the first year of production adjusted based on natural gas prices and inflation thereafter. 58 Pa. Cons. Stat. § 3218.

The Corbett Administration filed an appeal of that decision which is set to be heard by the Supreme Court of Pennsylvania on October 17, 2012.[117]

New York's approach to local control represents the other end of the spectrum. In that state, 26 localities have banned natural gas development or hydraulic fracturing altogether, two of which have been upheld as valid exercises of local zoning authority (Dryden 2012; Middlefield 2012). In addition, two bills have been proposed in New York that would allow local governments to enact or enforce laws and ordinances relating to oil, gas, and solution mining.[118]

In Colorado, the issue of local control over oil and gas drilling has become an increasingly prominent subject of discussion. Earlier this year, the Governor formed a multi-stakeholder task force to address the issue. The task force ultimately recommended "coordinated regulation through a collaborative approach…" (CDNR 2012), but what this means in practice remains to be seen. Five bills related to the topic of local control were introduced in the most recent legislative session.[119] In addition, four localities in the Front Range have moved to delay drilling pending a review of their oil and gas, land use, and public health laws; a fifth locality is currently considering a moratorium.[120] To date, the result of these reviews has been one set of final regulations issued by the City of Longmont, draft regulations issued by Boulder County,[121] and one set of operator agreements.[122] The City of Longmont finalized its ordinance in July 2012. The ordinance includes riparian and residential setbacks, disclosure requirements, water testing, wildlife protections, and a ban on drilling in residential areas.[123] Boulder County's draft revisions also contain residential and riparian setbacks, water-testing requirements, emergency response, and other measures intended to protect public health such as air-pollution controls.[124] Shortly after Longmont issued its ordinance, the Colorado Oil and Gas Conservation Commission filed a lawsuit against the City of Longmont alleging that state law preempts a

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[117] Scott Detrow, *StateImpact*, "Corbett Administration Filed Act 13 Appeal with State Supreme Court" (July 27, 2012), http://stateimpact.npr.org/pennsylvania/2012/07/27/corbett-administration-files-act-13-appeal-with-state-supreme-court/.

[118] A8557 (Aug. 24, 2011) (authorizes local governments to address natural gas drilling in their zoning or planning ordinances); A3245 (Jan. 24, 2011) (would allow local governments to enact and enforce local laws/ordinances of general applicability).

[119] SB 088, introduced Feb. 16, 2012 (would have granted COGCC exclusive jurisdiction to regulate oil and gas operations); HB 1173, introduced Feb. 6, 2012 (would have required closed-loop systems for hydraulic fracturing fluid storage/containment); HB 1176, introduced Feb. 6, 2012 (would have mandated setbacks of at least 1000 feet from any school or residence in urban areas); HB 1277, introduced Feb. 20, 2012 (would have stated that oil and gas operators would be subject to the same local government control as for other types of mineral extraction, i.e., a shared state and local approach); SB 107, introduced May 5, 2012 (contained specific requirements, such as closed-loop drilling, water reporting requirements, and the prohibition of the use of carcinogens in hydraulic fracturing fluids).

[120] As noted above, these include Boulder County, Erie, Longmont, and Colorado Springs. At the time this chapter went to publication, the town of Lafayette, Colorado, was considering a temporary ban on oil and natural gas drilling. *NGI's Shale Daily*, "Another Colorado City Considering Drilling Restrictions" (September 6, 2012).

[121] At the time this Chapter went to publication, the Boulder County Planning Commission was considering proposed Land Use Code amendments to address drilling in the County. The City of Longmont finalized its oil and gas revisions to its Municipal Code, Ordinance O-2012-25, on July 17, 2012.

[122] Copies of the agreements are available on the Town of Erie's website, http://www.erieco.gov/CivicAlerts.aspx?AID=487 (last visited September 25, 2012).

[123] City of Longmont Ordinance O-2012-25 (July 17, 2012).

[124] Boulder County, Docket DC-12-0003: Amendments to Oil and Gas Development Regulations, http://www.bouldercounty.org/find/library/build/dc120003stafrecregs20120924.pdf.

number of the purported protections including the riparian and wildlife setbacks, residential well-site ban, disclosure rule, water-testing requirements, a requirement that operators use multi-well sites, and visual mitigation measures.[125] The Oil and Gas Conservation Commission has yet to take an official position on Boulder County's regulations. Nevertheless, the Commission's suit against Longmont may indicate that the approach recommended by the Governor's Task force earlier this year will tilt in favor of state rather than local regulation, with the amount of control retained by the local governments unclear.

Local governments across all states covered in this study are also seeking to impose additional setback requirements, but the governing state law on these requirements varies by jurisdiction. Local setback requirements that are more stringent than state law exist in the Barnett Shale play, Eagle Ford play, Marcellus Shale play in Pennsylvania, and North San Juan basin. There is considerable variety in setback requirements, as well as increasing public interest in this issue. Lack of consensus regarding the appropriate distance required to protect against adverse air, noise, visual, or water pollution may, in part, explain the continuing controversy over setback requirements (CU 2012). For a comparison of specific state and local requirements, see Table 30, Appendix C, Setback Requirements.

2.5 Best Management Practices

Various commissions and reports have stressed the need for continuous improvement in industry practices, as well as industry-led organizations dedicated to developing and disseminating information on best practices (SEAB 2011b; NPC 2011; IEA 2012). Technological innovation in the effort to control and mitigate some of the resource and environmental impacts of unconventional gas development can improve efficiency, reduce environmental risk, and bolster public confidence. As in many industries, leading operators in unconventional gas development have often performed at a level over and above existing regulatory requirements, providing important sources of innovation for new practices and regulations. Notably, a handful of important regulatory developments started as best management practices adopted by leading operators.

For example, as noted above, prior to EPA's adoption of its recent NSPS for the oil and gas sector, leading companies implemented reduced-emission completions ("green completions") to increase profits by maximizing sales of natural gas from the recovery of natural gas otherwise lost to the atmosphere; others voluntarily report chemicals used in hydraulic fracturing fluids to the Groundwater Protection Council's public FracFocus website.[126] Today, a number of companies are developing methods to recycle and reuse flowback and produced waters that reduce operator costs, as well as the risks associated with other forms of disposal.[127] As discussed in the following chapter, documenting such beyond-compliance best practices is an area that merits further study.

[125] Colorado Oil and Gas Conservation Commission v. City of Longmont (filed August 30, 2012 in the Boulder County District Court).
[126] See Ground Water Protection Council Chemical Disclosure Registry, http://fracfocus.org/.
[127] See GIS Mapping Tool in Chapter 4 of this report.

2.6 Conclusion and Key Findings

The combination of hydraulic fracturing and horizontal drilling has been hailed by some as the most important energy innovation of the last century, with dramatic implications for the economics and politics of energy in the United States and throughout the world. This "disruptive" technology has fueled a boom in unconventional gas development in various parts of the United States over the last 10 years. Law and regulation (at multiple levels) have struggled to keep up with the rapid growth of the industry. And the contemporary legal and regulatory landscape that applies to unconventional natural gas development is complex, dynamic, and multi-layered.

The federal government has demonstrated a keen and growing interest in this area, as evident by the prominent role natural gas plays in the current Administration's energy policy (White House 2011), the formation of the SEAB Subcommittee, and the announcement or promulgation of a number of new rules related to air and water quality, data collection regarding the aggregate amounts of chemicals used in fracturing fluids, and development on public lands discussed above. Additional federal regulations and new legislation are also possible. The results of EPA's study on the effects of hydraulic fracturing on drinking water could play a key part in directing any such changes.

States will continue to serve as the major source of regulation, with primary responsibility for well-construction standards, disclosure requirements for hydraulic fracturing fluid chemicals and water used during well stimulation, baseline water-monitoring requirements, waste management, and overall compliance monitoring and enforcement. State and local requirements—other than disclosure requirements regarding chemicals and water usage—vary considerably, and this is likely to continue as more states revise their rules to respond to new development. Greater coordination between regulators at all levels of government could help to reduce uncertainty and fragmentation,[128] as would greater reliance on the expertise contained in organizations such as the State Review of Oil and Natural Gas Environmental Regulation and the Ground Water Protection Council (SEAB 2011a; SEAB 2011b).

State compliance monitoring and enforcement capabilities vary widely. The limited data that have been assembled indicate most violations are minor, but that "enforcement actions are sparse compared to violations noted" (Groat and Grimshaw 2012). Substantially more data and research are needed to understand the extent to which companies are complying with state, local, and federal requirements.

This information gap could begin to be filled by greater reporting, via self-certification requirements that are publicly available, as well as by state databases, searchable by the public, that contain compliance and enforcement records. These activities would also bring greater certainty to this issue.

A number of commissions and industry associations have expressed support for continued development and implementation of beyond-compliance measures (SEAB 2011b; NPC 2011; IEA 2012), and the need for such measures to avoid controversy, delay, and continued

[128] For example, BLM's recent proposed rule notes the importance of consistency in federal and state disclosure requirements and the intent to provide consistency by lining up its requirements with those adopted in leading states.

opposition in certain parts of the country. As discussed in the following chapter, more work is needed to identify and evaluate such measures. Given the rapid pace of unconventional gas development in various parts of the country, best practices will have to complement regulation—and, in some cases, be folded into it. But as the regulatory landscape evolves, it will be important to establish a framework, where possible, that incentivizes the ongoing development and adoption of new state-of-the-art practices and technologies to minimize the risks associated with developing natural gas resources.

3 Key Issues, Challenges, and Best Management Practices Related to Water Availability and Management

3.1 Introduction and Objectives

Shale gas development has several categories of potential risks including air, water, land, and community (Figure 13). Examples of air risks include emissions of GHGs (largely methane) and hazardous air pollutants (e.g., benzene). Land impact risks include ecosystem degradation and land disturbance. Related to water, the risks are either quantity related (regional water depletion) or concerns of quality (surface or groundwater contamination). Community risks include excessive truck traffic and the noise, road damage, and other associated impacts. Induced seismicity is also considered a community issue and the broadest community risk from it could be the loss of the social license to operate (e.g., Energy Institute 2012; Robinson 2012; Zoback et al. 2010.)

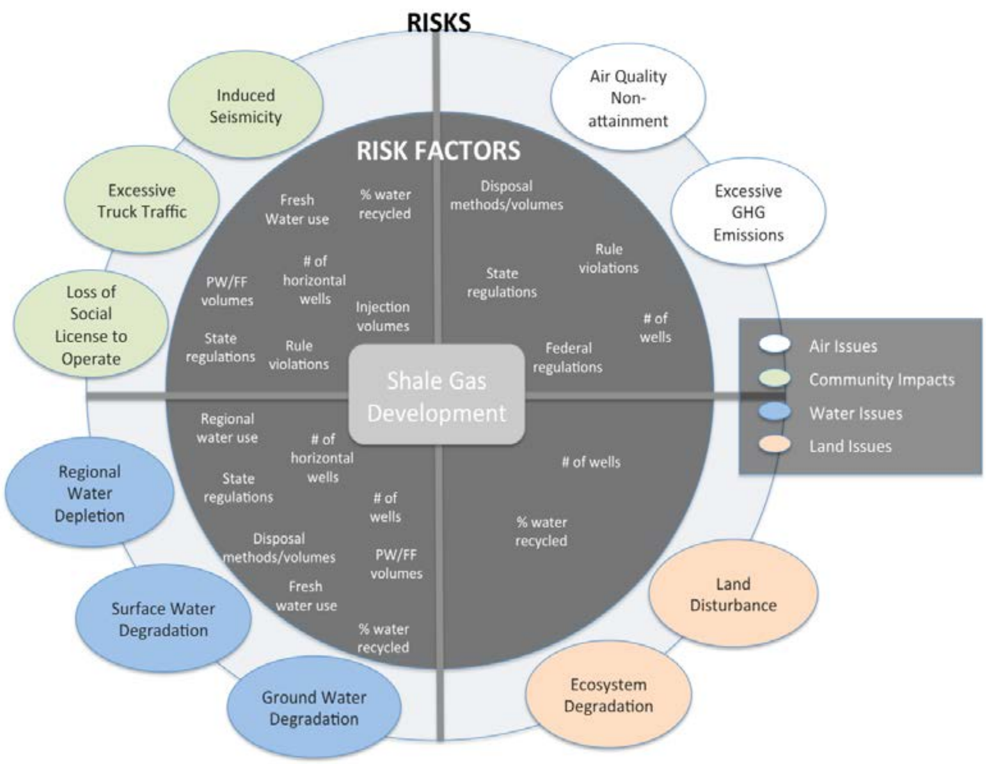

Figure 13. Description of shale gas development risks and characterization metrics

This chapter focuses on the risks and impacts of shale gas development on water resources. Ongoing improvement of the quality and quantity of water resource-related data will inform decisions related to shale gas development. Data collected in this chapter mark the beginning of the risk characterization needed to adequately define best management practices. Specifically, unconventional shale gas development might impact water resources through four major causal routes—one related to water quantity and three related to water quality.

- Water Quantity:
    - Regional water depletion due to large volumes of freshwater use for hydraulic fracturing
- Water Quality:
    - Surface and groundwater degradation resulting from inadequate construction practices and well integrity
    - Surface and groundwater degradation resulting from inadequate onsite management of chemicals used in hydraulic fracturing
    - Surface and groundwater degradation resulting from inadequate wastewater management practices

To better understand the risks to water resources from shale gas production, the variety of risk factors related to water need to be further defined and a thorough spatial and temporal characterization should be completed. The science regarding risks and impacts of the shale gas industry is relatively new and still in a state of flux (EDF 2012; IEA 2012). For this project, we approached the topic by using available literature studies, public databases, and industry interactions.

We established the following objectives to assess the risks to water resources:

- Understand the quantities of water currently being used in six shale plays in the United States as they relate to current estimates of water availability and existing water uses
- Understand the quantities of flowback and produced water for each shale play and the wastewater management techniques employed
- Identify Best Management Practices, including quantity and quality impacts and costs

To accomplish these objectives, we studied six unique natural gas producing regions of the country (as identified in Chapter 2) to capture the spatial variability of water use, water availability, and wastewater management (see Table 8). The six regions include a coalbed methane (CBM) basin (North San Juan); a vertically fractured tight sand basin (Upper Green River); three primarily dry gas shale formations (Barnett, Haynesville, and Marcellus); and one shale formation that is producing condensates and oil along with natural gas (Eagle Ford).

3.2 Importance of Water for Shale Gas Development

The recent expansion of shale gas development is, in part, due to advances in horizontal drilling and hydraulic fracturing. As shale gas development continues to grow rapidly across the U.S., the demand for water used during site operations is also expected to increase (COGCC 2012b). Drilling and fracking operations involved in shale gas development require millions of gallons of water per well that must be acquired and transported to sites to fracture the shale formations (EPA 2011). Hydraulic fracturing is essential for tight formations such as shale because the geological structure does not have the necessary permeability to allow natural gas to flow freely through the formation and into a wellbore (Arthur 2011). The current development of unconventional shale gas would not be economically viable without hydraulic fracturing, making it important to have an adequate, dependable supply of water to support fracking operations. Equally important is preventing fracking operations from negatively affecting a region's water resources, both in terms of quantity and quality.

Water used in hydraulic fracturing comes from several sources including surface water, groundwater, municipal potable water supplies, or reused water from other water sources (Veil 2010). To date, freshwater has been used for most hydraulic fracturing operations in most regions (Nicot 2012). Surface water, such as streams, rivers, creeks, and lakes, are the largest source of fresh water for operators in the Eastern United States. Groundwater can be a feasible source of water, but only when sufficient amounts are available. In Texas, groundwater is more commonly used than surface water. Public water supply might be an alternative in some regions, because permits for surface and groundwater can take more time to secure.

The impact of water usage will depend on the availability of local water resources, which can vary regionally depending on the geographic location of the shale play, ground and/or surface water sources, and competing demands for water from other users. In locations vulnerable to droughts, operational water needs could adversely impact the viability of gas production from tight formations (Vail 2010). Droughts, particularly in water-stressed regions (such as the arid Southwest), can limit the amount of available water, increasing the competition for water between potable water supplies, water for agriculture, and water for fuel.

3.3 Assessment of Risks to Water Quantity and Water Quality

Shale gas development may incur risks to both regional water quantity and quality. Quantity-related risks depend on the number of wells drilled, water use per well, amount of recycling or non-potable water use that occurs to offset freshwater demands, and local water availability. Quality-related risks depend on onsite construction techniques, onsite chemical management practices, and wastewater management practices. Risks may vary for any given shale gas development site. In many cases, risks to water resources extend beyond the location of the well being drilled, depending on the source location of the water and where wastewater is treated. Figure 14 shows the various risks to water resources that can result from hydraulic fracturing operations.

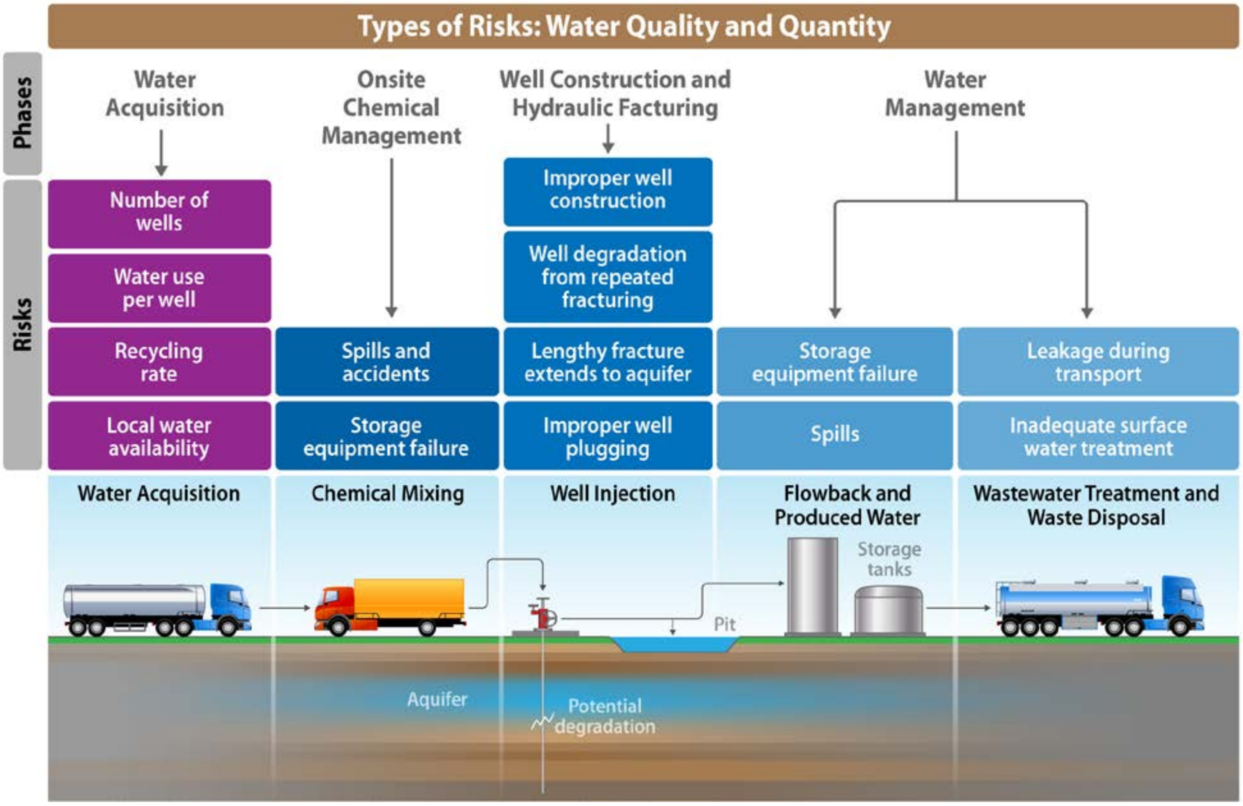

Figure 14. Water quality risks by phase of natural gas production.[129]

3.3.1 Risks to Water Quantity

3.3.1.1 Current Industry Activities Affecting Water Use

A crucial component of hydraulic fracturing is securing a sufficient amount of water for operations. Water may not always be available on the lease site; therefore, developers may have to obtain access to water from a different location and transport water to the site. In such cases, the risks to water resource quantities are assessed with respect to the water's source location, not to where it is eventually used. Where operators source their water depends on several factors, such as location, availability, timing, and cost. The closer a water source is to a well, the lower are the operational costs, whether it be pumping or transporting the water by truck.[130] In many cases, the total amount of water required for multiple operating wells (and the permits required) will be greater than local daily flows. For example, in Pennsylvania, the Susquehanna River Basin Committee (SRBC), which oversees all water source permits in the basin, has approved permits totaling 108 MGD (million gallons per day) at 151 locations (as of September 1, 2011), whereas the estimated peak daily withdrawal of those locations is only around 30 MGD. This means that freshwater impoundments might need to be constructed to collect and store water over a period of time to eventually be used to supply water for drilling and developing multiple wells (SRBC 2012).

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[129] Graphic adapted from (EPA, 2011).

[130] Trucks can often have an impact on rural roads, both in terms of increased traffic and increased wear on roads. Analysis of these impacts is beyond the scope of this paper.

Total water use at a shale gas development site depends on the number of wells drilled, water use per well, and amount of recycling that occurs. The term water "use" is used in this chapter, which, in part, reflects the ambiguity of whether the water usage reported in publicly available sources represents freshwater withdrawals, use of freshwater along with recycled water, water consumption, or a combination of these categories. Future research could clarify the definitions of water usage reported by industry.

Number of wells

In the areas for which data are available, the number of producing wells drilled each year has been increasing since 2009 (Figure 15).

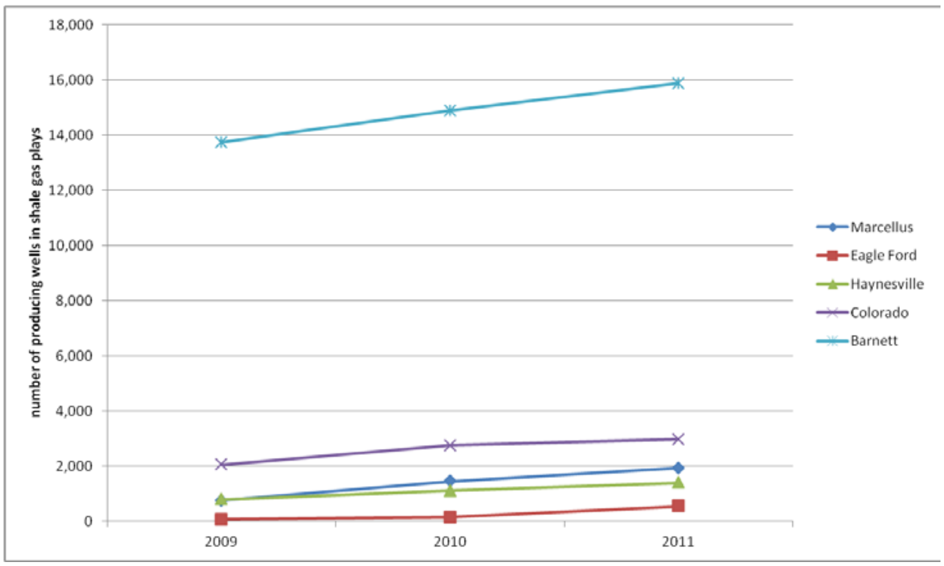

Figure 15. Total number of producing wells in shale gas plays, 2009–2011 (TRRC 2012c; COGCC 2012b; LADNR 2012; PA DEP 2012a; Eagle Ford Shale 2012).

The greatest number of wells is in the Barnett Shale formation, increasing 16% from 2009 to 2011, with nearly 16,000 producing wells (TRRC 2012c). In the other formations considered in this study, the total numbers of wells are smaller, but have been increasing faster. From 2009 to 2011, the total number of wells increased by 45% in Colorado (COGCC 2012b), 76% in the Haynesville formation (LADNR 2012), 154% in the Marcellus formation (PA DEP, 2012a), and 721% in the Eagle Ford formation (Eagle Ford Shale 2012). In all of these formations, well drilling applications have continued to increase each year, indicating a continued trend for the near future.

Water use per well

Data on the water usage per well were available for five of the six regions considered here. Data from about 100 nominal wells were randomly collected for four regions (Marcellus, Barnett, Eagle Ford, and Haynesville) from www.fracfocus.org, a voluntary online chemical disclosure registry of the water used for fracturing. FracFocus provides statewide and county-wide data. Well data are classified according to their API number, county, fracture date, operator name, well name, well type (Oil/Gas), latitude, longitude, datum, and total water use (including fresh water, produced water, and/or recycled water). Water use statistics are compiled and are displayed in Appendix D.

Average water use from the 100-well study in the five regions ranges from 1.1 to 4.8 million gallons per well, with a multi-region average of 3.3 million gallons per well (Figure 16).

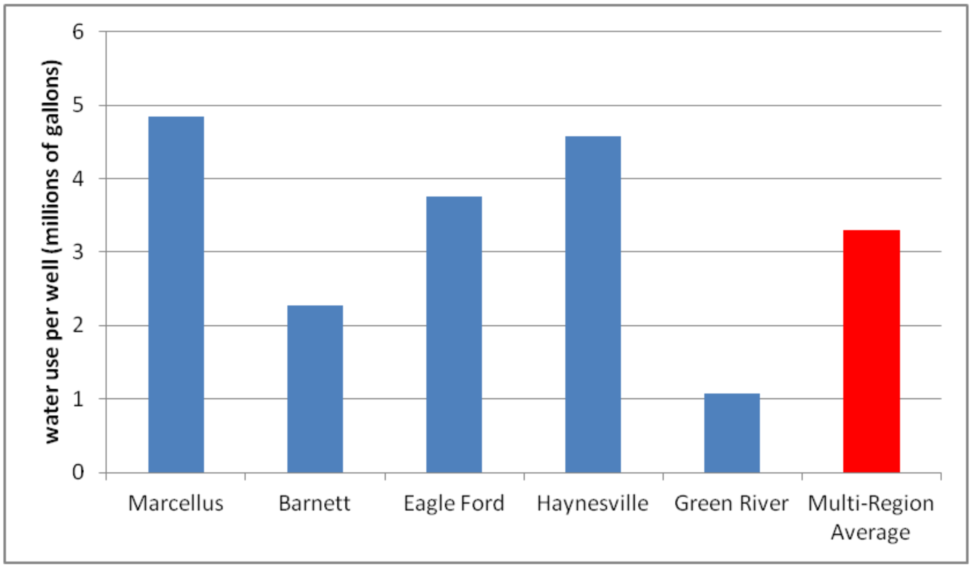

Figure 16. Average water use per well (in millions of gallons) for five regions (2011) (Fracfocus.org).

The Barnett, Eagle Ford, and Green River formations had average water uses of less than 4 million gallons per well, and the Marcellus formation had the highest average water use of 4.8 million gallons per well. Furthermore, considerable variation in water use per well within each formation is shown in Figure 17.

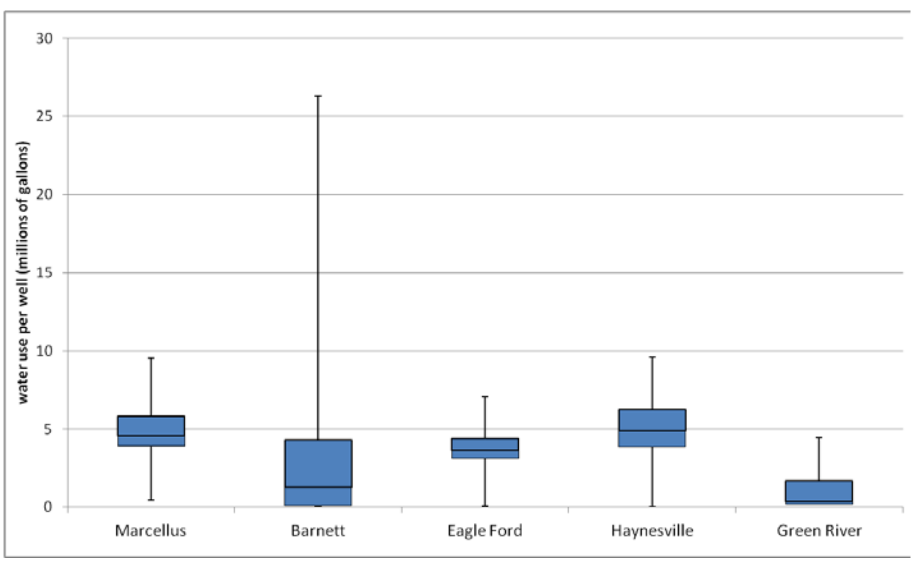

Figure 17. Water use per well for four formations, in millions of gallons. (fracfocus.org)

Note: Low and high error bars represent minimum and maximum reported water usage per wells, respectively. Upper and lower ends of boxes represent 75th and 25th percentile, respectively. Horizontal lines in boxes represent medians.

Results of the 100 well analyses indicate that water usage per well can vary by up to three orders of magnitude (29,000 gallons to 26 million gallons per well in the Barnett formation) depending on geology, type of well and drilling techniques, and industry practices. Median estimates of water usage per well are around five million gallons for the Marcellus, Eagle Ford, and Haynesville formations, yet individual wells can vary greatly. The Barnett formation has the second lowest median value of 2.3 million gallons per well, yet also the highest individual well value of 26 million gallons per well. These statistics do not indicate whether a portion of the water utilized for hydraulic fracturing includes recycled water.

Recycling rates

The impacts on local freshwater resources can be reduced by recycling produced water and frac flowback water. To use wastewater, a series of steps are commonly employed (Mantell, 2011). The water must often be stored in onsite holding tanks before treatment and is filtered or transported to another storage tank to test its remaining constituents. The water is then pumped or otherwise transported to another well location for reuse. Currently, only Pennsylvania tracks the amount of produced water and frac flowback water being recycled for reuse for drilling and hydraulic fracturing operations. Other states considered in this analysis do not have recycling or reuse as a category in their annual reporting forms, yet recycling may be occurring. In Pennsylvania, recycling of produced water has increased from 9% in 2008 to 37% in 2011 (PA DEP 2012b). In general, recycling of frac flowback water has increased from 2% in 2008 to 55% in 2011. In 2011, based on data reported, this recycling led to the reuse of about 65,000 gallons of produced water per well and 120,000 gallons of frac flowback water per well (Figure 18).

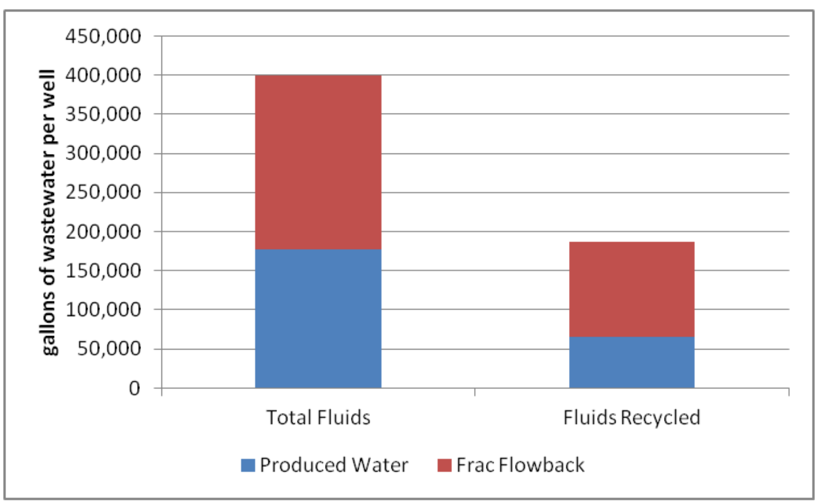

Figure 18. Wastewater production and total recycling at shale gas operations in Pennsylvania in 2011 (PA DEP 2012b)

Although data are not available for recycling rates in other formations, certain state organizations actively encourage recycling practices. The Railroad Commission (RRC) of Texas has provided authorization for seven recycling projects in the Barnett formation, five of which are still active (TRRC 2012d). No recycling authorizations have been given for the Eagle Ford or Haynesville formations to date. The Colorado Oil and Gas Conservation Commission (COGCC) actively encourages reuse and recycling of water used in well construction as well as produced water. Although there are no data of quantities, the COGCC notes that several operators in the Piceance Basin have constructed infrastructure for reusing water for drilling and completing new wells (COGCC, 2012b).

The feasibility of recycling and reusing produced water and frac flowback depends, in part, on how much and how quickly water returns to the surface. In the Marcellus and Barnett shale formations, Chesapeake Energy reports that about 500,000 to 600,000 gallons per well will return to the surface in the first 10 days, compared to about 250,000 gallons per well in the Haynesville formation (Mantell, 2011). How much of the produced water can be recycled depends on the chemical composition of the water, including its total dissolved solids (TDS), total suspended solids (TSS), and its concentration of chlorides, calcium, and magnesium. High TDS can increase unwanted friction in the fracking process. High TSS can plug wells and decrease the effectiveness of biocides. High concentrations of other elements can lead to high risks associated with scaling.

Recycling produced water and frac flowback can partially reduce the demand for freshwater sources for new hydraulic fracturing operations. The reduction in freshwater demand is limited by the amount of water that is returned to the surface. In general, the amount of water returned to the surface—and thus, the amount of water that could be recycled—is on the order of 10% of the freshwater requirements for developing a well with hydraulic fracturing. The volumes of produced water may vary widely from well to well, making it difficult to predict how much water is produced and how much recycling potential there is for each well.

Water availability

Local water availability conditions in the six study regions can vary greatly. Further information of each shale region can be found in Appendix D. An overview of the six regions is shown in Figure 19.

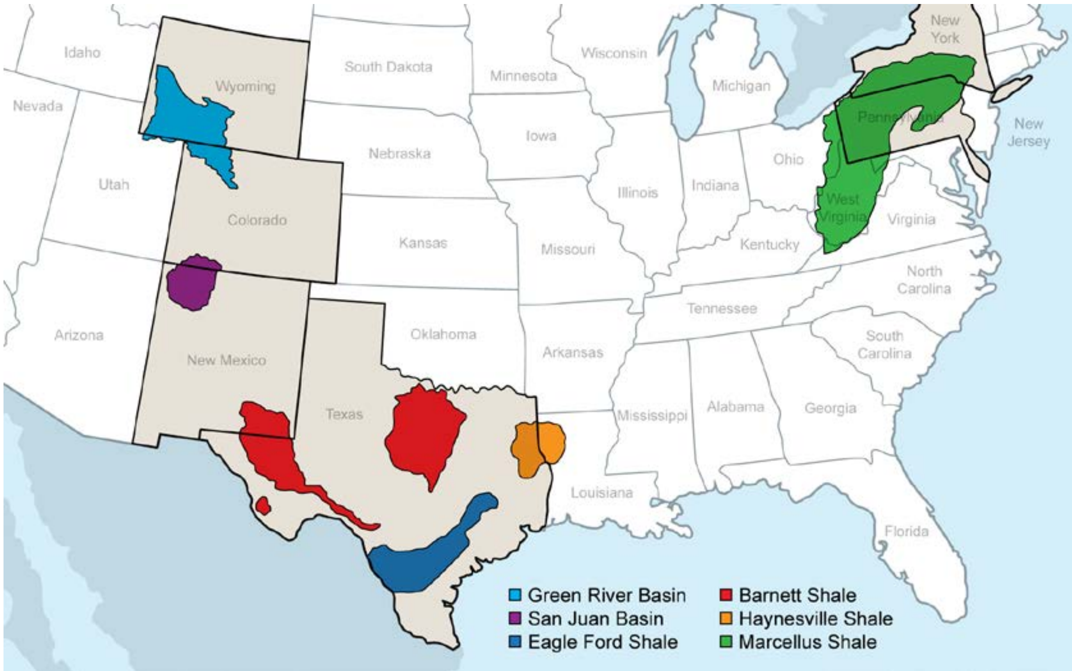

Figure 19. Six shale plays considered in this study.

Marcellus Shale, PA

The Marcellus Shale is located within or nearby highly populated areas of the northeast U.S. occupying the states of New York, Pennsylvania, Maryland, West Virginia, and Ohio. Competition for water might be challenging for shale gas development. However, the area overlying the Marcellus Shale formation has abundant precipitation, making water readily available (Arthur 2010). Three major watershed basins overlie the formation: the Susquehanna, Delaware, and Ohio River Basins are the main suppliers of water for shale gas development. The Marcellus Shale is overlain by about 72% of the Susquehanna River Basin (SRB), 36% of the Delaware River Basin, and about 10% of the Ohio River Basin (Arthur 2010). The SRB drains 27,510 square miles, covering about half the land area of Pennsylvania and portions of Maryland and New York (Arthur 2010). Major streams and rivers in the SRB are potential surface water withdrawals for shale gas development.

Texas water

Texas has dominated shale gas production in the U.S. over the past decade. The Barnett Shale was the sole producer in the early 2000s and accounted for about 66% of the U.S. shale gas production from 2007 to 2009 (Nicot 2012). Texas is subject to drought and wet period cycles that might become extreme with climate change and impact the water available. Water requirements are reported to the RRC of Texas. Surface water is owned and managed by the State and requires a water-right permit for diversions. Groundwater is owned mostly by landowners, but is generally managed by legislatively authorized groundwater conservation districts (Nicot 2012). Groundwater is generally available in each of the shale gas plays, and unlike surface water, groundwater is located close to production wells.

Barnett Shale, TX

The Barnett Shale is located in central Texas around the Dallas-Ft. Worth area. Precipitation is variable across the state of Texas. The mean annual precipitation in the Barnett area is about 790 mm per year (Nicot 2012). About 60% of the water used in hydraulic fracturing operations in the Barnett Shale play comes from groundwater sources, specifically the Trinity and Woodbine aquifers in North Central Texas (Andrew et al. 2009). The Trinity Aquifer extends from south-central Texas to southeastern Oklahoma, and groundwater use varies across the Barnett Shale development area. For example, groundwater provides about 85% of total water supply in Cooke County, but only 1% for Dallas County (Andrew et al. 2009). Extensive development of the Trinity Aquifer in the Dallas-Ft Worth metropolitan area had caused groundwater levels to drop more than 500 feet in some areas (Andrew et al. 2009). For many rural areas, groundwater from the Trinity Aquifer remains the sole water source. Water use can vary widely from county to county depending on the pace of shale gas development. Municipal water use is dominant (greater than 85%) in the footprint of the Barnett Shale play in Denton and Tarrant counties; elsewhere, water use is mixed with some irrigation and manufacturing (Nicot 2012). Surface water is available in the Barnett Shale area, including major rivers and reservoirs; however, population growth is expected to increase demand for water resources and cause increasing competition. It is predicted that the net water use for shale gas production in the Barnet Shale play will increase from 1%–40% at the county level for selected counties (Nicot 2012).

Eagle Ford Shale, TX

The Eagle Ford Shale play is located in South Texas. The mean annual precipitation in the Eagle Ford Shale is about 740 mm per year (Nicot 2012). Surface water in the Eagle Ford Shale region is not as readily available and abundant as the northeast sections of Texas. A small portion of the Rio Grande River at the Mexican border is used, and several streams are ephemeral and recharge underlying aquifers. However, even when surface water is available, it is often not located adjacent to sites; therefore, trucking and piping of water is often required. Operators rely mostly on groundwater from the Carrizo Aquifer, though groundwater has already been partially depleted for irrigation in the Winter Garden region of South Texas (Nicot 2012). Over-extraction of groundwater for irrigation in the past limits water availability for current and future shale gas production (Nicot 2012). Water used in south Texas is variable; municipal water use is dominant (greater than 85%) in the footprint of the Eagle Ford in Web County (Nicot 2012). It is predicted that during the peak years of production, the net water use for shale gas production in the Eagle Ford Shale region will increase from 5% to 89% at the county level for selected counties (Nicot 2012).

Haynesville Shale, LA

The Haynesville Shale is located in East Texas and western Louisiana. The eastern part of Texas has high precipitation, with a mean annual precipitation of 1,320 mm per year, resulting in a widespread and abundant supply of surface water (Nicot 2012). The region also hosts large aquifers, specifically, the Carrizo Wilcox and Queen City/Sparta Aquifers. Shale gas production in Louisiana relies heavily on local groundwater from the Carrizo Aquifer and currently derives about 75% of the water from surface water or lesser-quality shallow groundwater (Nicot 2012). The groundwater is more readily available in East Texas, with the only competition for water use being industrial and municipal demands (Nicot 2012). Furthermore, it is predicted that during the peak years of production, the net water use for shale gas production in the Haynesville Shale region will increase from 7% to 136% at the county level for selected counties (Nicot 2012).

San Juan Basin, CO

The San Juan Basin is located in the arid Southwest U.S., occupying the Four Corners area of Colorado, New Mexico, Arizona, and Utah. The basin is characterized by a wide range of topographic settings that include valleys, canyons, badlands, uplands, mesas, and buttes (Haerer 2009). Precipitation in the San Juan Basin varies regionally. Annual precipitation in the high mountain areas in Colorado can receive as much as 1,020 mm per year, whereas annual precipitation in lower altitudes of the central basin in New Mexico can receive less than 200 mm per year (Levings 1996). Runoff water from snow and precipitation, which flows into rivers such as the San Juan River, makes up a large portion of the surface water. However, because of high evaporation rates and the hot and dry climate of the Southwest, surface water in the basin is limited and has already been fully appropriated.

Thus, groundwater resources tend to be the only source of water in most of the basin, and they are used mainly for municipal, industrial, domestic, and stock purposes (Levings 1996). The San Juan structural basin is a major oil and gas producing area, and groundwater is produced as a byproduct of these operations (Levings 1996). Several major aquifers exist in the basin; most are unconfined and located within the Tertiary formations (Haerer 2009). The amount of available water varies, depending on the underlying geological rock formations. For example, the Fruitland Formation and Pictured Cliffs Sandstone are aquifers that are sources of drinking water along the northern margin of the basin and act as a single hydrologic unit. The Ojo Alamo Sandstone is the primary aquifer for the southern margins and is a possible source of groundwater (EPA 2004). Groundwater levels in the Fruitland Formation have declined significantly due to the development of energy resources in the San Juan Basin (Levings 1996).

Green River Basin, WY

The Green River Basin is located in the southwest corner of Wyoming, northwest Colorado, and northeast Utah. The basin drains to the Green River, a major tributary to the Colorado River. On average, the basin receives about 250–400 mm of precipitation annually and less than 13% of the basin receives more than 500 mm (WWDC 2010). Precipitation is highest during the months of April and May and the least in December and February. There are four regional aquifer systems in the Wyoming side of the Green River Basin. The Cenozoic, Mesozoic, Paleozoic, and Precambrian aquifer systems range from the youngest and most heavily used to the oldest and least used, respectively (WWDC 2010). There has been relatively little development of groundwater resources in the Green River Basin, and the recent increase in shale oil and gas development has relied on groundwater resources as the primary supply to the industry. In Wyoming, irrigated agriculture is the largest water consumer. However, the energy and mineral sectors have historically added volatility in water use and allocation, requiring large amounts of water (WWDC 2010). Groundwater in the basin is used for domestic and pubic supplies, and industrial uses including mining and irrigation. Oil and gas development has increased substantially in the Green River Basin and accounts for a large part of the increase in groundwater use (WWDC 2010).

3.3.1.2 Current Water Quantity Risks Resulting from Industry Activities

Risks to water quantity resulting from industry practices in shale gas development include reductions in both available surface water and groundwater. These risks occur in the areas from which water resources are sourced, not necessarily the hydraulic fracturing site. In areas where the levels of the groundwater table are already affected by multiple sectors' uses (e.g., agriculture, municipal water supply), large increases in use by any sector might affect water availability or the cost of pumping for all other users.

The water quantity risk to any given water basin depends on how much water is used and on the local water availability. Water usage in shale gas development, as described above, depends on the total number of wells, water use per well, and recycling rate. Water availability depends on local geologic and climatic conditions and on competing users of water. In the study regions, the total number of producing wells has been increasing steadily since 2008. With the exception of Pennsylvania, there are no data indicating a substantial increase in the recycling rate of wastewaters, and the total quantities of freshwater used for hydraulic fracturing have been increasing. The impact of recycling on reducing freshwater demands is limited by the amount of flowback and brine produced from each well. The use of non-freshwater sources, such as shallow brackish waters, could alleviate demands on freshwater; but there are no readily available data on availability or current usage of these water sources for shale gas operations.

Values of total water available physically and legally can be difficult to quantify, but our report analyzes the water usage of oil, gas, and mining activities as a percentage of all other existing water uses. On a state level, the amount of water currently withdrawn for hydraulic fracturing is a relatively minor fraction of total water withdrawals. In Colorado for example, total water diversions for hydraulic fracturing represent only 0.1% of all water diversions in the state (COGCC 2012b). In Texas, mining activities, which include hydraulic development, accounted for just 2% of total water withdrawals in 2011 (TDWB 2012).In Texas and Colorado, irrigation accounts for more than 55% and 85%, respectively, of total water withdrawals (COGCC 2012b; TDWB 2012).

Greater insights into risks to water resources can be gained by analysis on a geospatial scale smaller than the states, such as the county level. In many counties where shale gas development sites are located, mining activities already account for a substantial percentage of existing water usage (Figure 20) (Kenny et al. 2009).

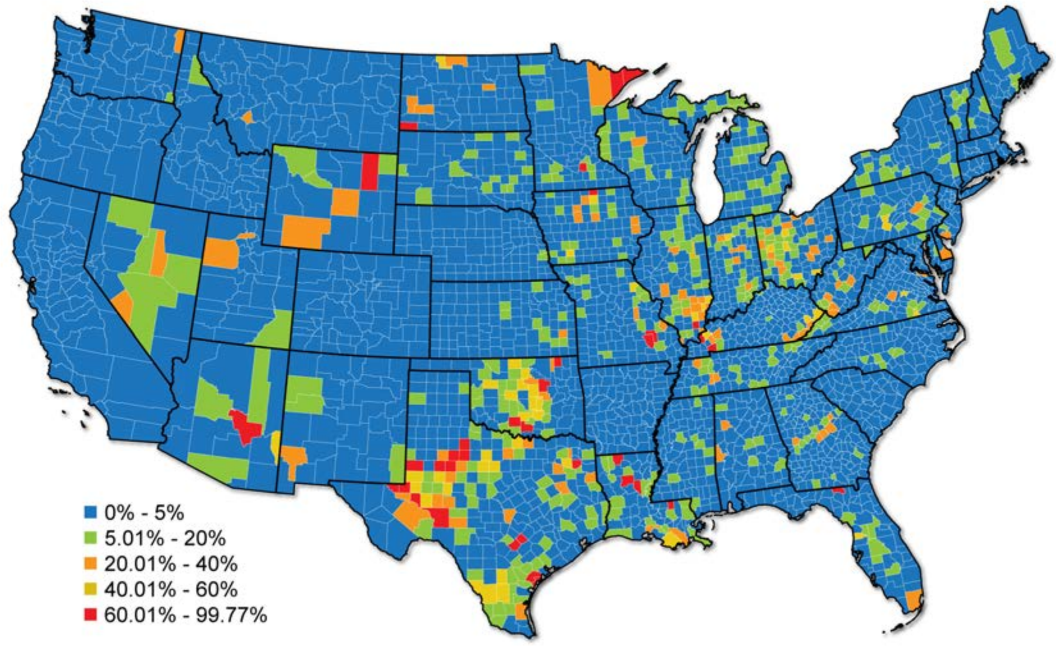

Figure 20. Mining water withdrawals as a percent of total water withdrawals, 2005 (Kenny 2009).

In 2005, mining activities in Texas counties that overlapped with the Barnett, Eagle Ford, and Haynesville formations accounted for a large percentage of total water withdrawals. Similarly, counties in Louisiana overlapping with the Haynesville formation, counties in New Mexico overlapping with the Barnett and San Juan formations, and counties in Wyoming overlapping with the Green River formation show that mining activities account for water withdrawals representing 5% to over 60% of total withdrawals in that county. Thus, water use for mining activities already represents a substantial portion of total water usage in the regions where shale gas development is occurring. Rapid expansion of water required for hydraulic fracturing could impact local water availability, depending on water resources in each region. Further research is needed to evaluate the impact that the current and projected water use for mining activities, including hydraulic fracturing, could have on the water resources and other water demands in these regions.

3.3.2 Risks to Water Quality

3.3.2.1 Current Industry Activities Affecting Water Quality

Risks to water resources depend on well and drilling construction practices, handling of chemicals on site, and wastewater management. Risks to water quality can occur at both the location of hydraulic fracturing and where water is stored or treated.

Onsite well-construction and hydraulic fracturing practices

In terms of risk to water resources, well design and construction phase is a crucial component of the hydraulic fracturing process. Proper well construction can separate the production operations from drinking water resources. Well construction involves drilling, casing, and cementing—all of which are repeated multiple times until a well is completed. Drilling is conducted with a drill bit, drill collars, drill pipe, and drilling fluid such as compressed air or a water- or oil-based liquid (EPA 2011). Water-based liquids typically contain a mixture of water, barite, clay, and chemical additives (OilGasGlossary.com 2010). Once removed from the well, drilling liquids and cuttings must be treated, recycled, and/or disposed of.

Casing is steel pipe that separates the geologic formation from the materials and equipment in the well, and that also provides structural support. The casing is designed to withstand the external and internal pressures during the installation, cementing, fracturing, and operation of the well. Some operators might forego casing, in what is called an open-hole completion, if the geologic formation is considered strong enough structurally to not collapse upon itself. Casing standards vary regionally and are set by state regulations. Once the casing is in place, a cement slurry is pumped down the inside of the casing and forced between the formation and the casing exterior. The cement serves as a barrier to migration of fluids up the wellbore behind the casing, as well as a structural support for the casing. The cement sheath around the casing and the effectiveness of the cement in preventing fluid movement are the major factors in establishing and maintaining the mechanical integrity of the well; however, even a properly constructed well can fail over time due to stresses and corrosion (Bellabarba et al. 2008). For a given well, there may be multiple levels of drilling, casing, and cementing to prevent contamination of local water resources (Figure 21).

Once the well is constructed, the formation is hydraulically fractured. The hydraulic fracturing occurs over selected intervals where the well is designed to permit fluids to enter the formation. Hydraulic fracturing fluids, by volume, are mostly water and propping agents such as sand, designed to facilitate the fracturing and keep the new fractures open.

The chemicals present in hydraulic fracturing fluids can react with naturally occurring substances in the subsurface, causing these substances to be liberated from the formation (Falk et al. 2006; Long and Angino 1982). These naturally occurring substances include formation fluids (brine), gases (natural gas, carbon dioxide, hydrogen sulfide, nitrogen, helium), trace elements (mercury, lead, arsenic), radioactive materials (radium, thorium, uranium), and organic materials (organic acids, hydrocarbons, volatile organic compounds).

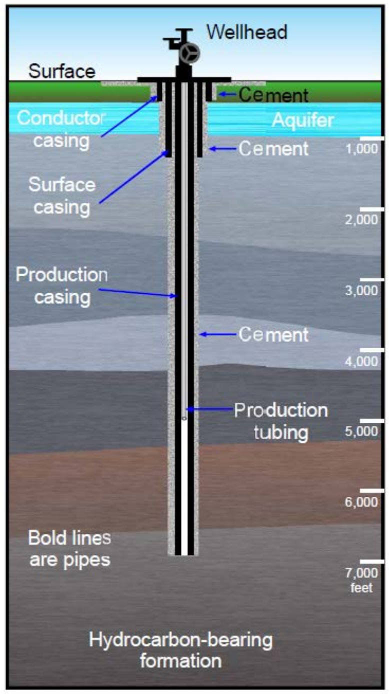

Figure 21. Schematic of well that includes several strings of casing and layers of cement (EPA 2011)

Once a well is no longer producing gas economically, it can either be re-fractured or plugged, to prevent possible fluid migration that could contaminate soils or waters (API 2009). A surface plug is used to prevent surface water from seeping into the wellbore and migrating into groundwater resources.

Onsite handling of chemicals

The chemicals used in fracking fluids are often mixed together on site with the propping agent (usually sand) and water. The types of chemicals and their volumes might vary from site to site and from developer to developer, depending on formation properties and developer common practices. Chemicals are stored on site in tanks before mixing and hydraulic fracturing operations begin. In general, 0.5% to 2% of the total volume of fracking fluid is made up of chemicals (GWPC and ALL Consulting 2009). The composition and relative amounts of chemicals might change from site to site. Table 6 provides an example of the variety and amounts of chemicals that comprise fracking fluid, where chemicals contribute 0.5% of the volume.

Table 6. Example Composition of Hydraulic Fracturing Fluids (GWPC and ALL Consulting 2009; API 2010)

Component	Example Compounds	Purpose	Percent Composition (by Volume)	Volume of Component (Gallons)[131]
Water		Deliver proppant	90	2,970,000
Proppant	Silica, quartz sand	Keep fractures open to allow gas flow out	9.51	313,830

[131] Based on the average water use per well identified in this study, 3.3 million gallons

Component	Example Compounds	Purpose	Percent Composition (by Volume)	Volume of Component (Gallons)[131]
Acid	Hydrochloric acid	Dissolve minerals, initiate cracks in rock	0.123	4,059
Friction Reducer	Polyacrylamide, mineral oil	Minimize friction between fluid and pipe	0.088	2,904
Surfactant	Isopropanol	Increase viscosity of fluid	0.085	2,805
Potassium Chloride		Create a brine carrier fluid	0.06	1,980
Gelling Agent	Guar gum, hydroxyethyl cellulose	Thicken fluid to suspend proppant	0.056	1,848
Scale Inhibitor	Ethylene glycol	Prevent scale deposits in pipe	0.043	1,419
pH Adjusting Agent	Sodium carbonate, potassium carbonate	Maintain effectiveness of other components	0.011	363
Breaker	Ammonium persulfate	Allow delayed breakdown of gel	0.01	330
Crosslinker	Borate salts	Maintain fluid viscosity as temperature increases	0.007	231
Iron Control	Citric acid	Prevent precipitation of metal oxides	0.004	132
Corrosion Inhibitor	N,N-dimethyl formamide	Prevent pipe corrosion	0.002	66
Biocide	Glutaraldehyde	Eliminate bacteria	0.001	33

In this example, we consider the average water use per well as identified in this study to be 3.3 million gallons. Therefore, the total volume of chemicals used—0.5% of the fracking fluid volume—is about 16,500 gallons per well. The total average volume of chemicals used in hydraulic fracturing fluids ranges from 5,500 to 96,000 gallons per well, given the wide range of water use per well, in addition to the chemical composition (Table 7).

Table 7. Estimates of Total Gallons of Chemicals Used per Well

	4.6 million gallons per well (average estimate)	2.3 million gallons per well (low estimate)	7.3 million gallons per well (high estimate)
Lower bound of chemical composition (0.5% of volume)	16,500 gallons	5,500 gallons	24,000 gallons
Upper bound of chemical composition (2.0% of volume)	66,000 gallons	22,000 gallons	96,000 gallons

Wastewater management practices

After hydraulic fracturing operations, pressure decreases and fluids return to the surface before the well begins formal gas production. Although there are no standardized definitions, the used fracking fluids (frac flowback) and naturally occurring water resources (produced water) both return to the surface. In general, the frac flowback returns first at high rates (e.g., ~100,000 gallons per day) for a few days; then produced water surfaces at lower rates for the remainder of the well's lifetime (e.g., ~50 gallons per day). The rates of production and total volumes of frac flowback and produced water vary greatly within and between shale plays—ranging from 10% of original fracking fluid volume to as high as 75% (EPA 2011). Frac flowback and produced water both contain naturally occurring substances, including oil, gas, radionuclides, volatile organic compounds, and other compounds that could contaminate local water resources.

Frac flowback and produced water are stored on site in storage tanks or impoundment pits prior to treatment, recycling, and/or disposal (GWPC 2009).Onsite impoundments can be designed for short-term use (for storage purposes) or for long-term use (evaporation pits), and impoundment regulations and requirements can vary greatly by location.

Operators have a variety of options for managing wastewaters, including recycling and reusing, onsite evaporation in impoundments, onsite injection into wells, disposal at a centralized facility through evaporation or underground injection, and treatment through surface water treatment plants. Overall, national disposal methods are dominated by underground injection (EPA 2011). Current industry practices might vary from state to state, and have shown different trends from 2008 to 2011. For example, Colorado (Figure 22) and Pennsylvania (Figure 23) show stark differences and trends.

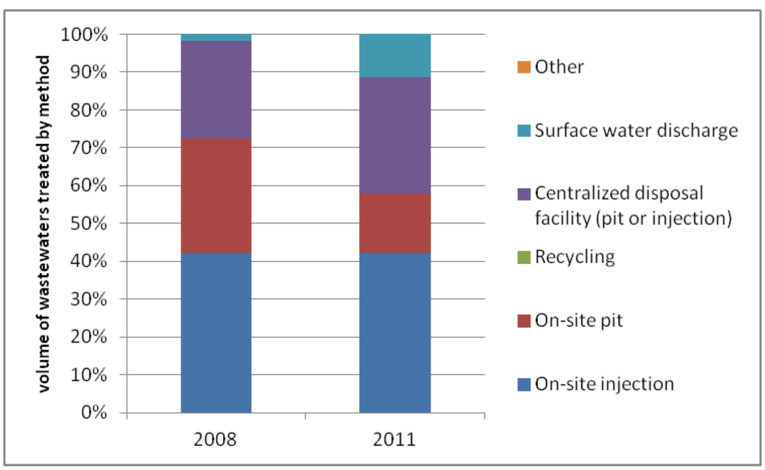

Figure 22. Colorado wastewater treatment methods, 2008–2011 (COGCC 2012a)

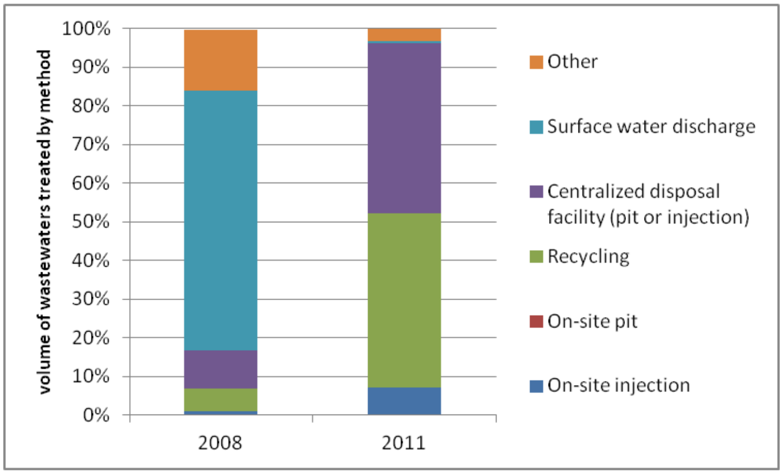

Figure 23. Pennsylvania wastewater treatment methods, 2008–2011 (PA DEP 2012b)

In Pennsylvania, surface water treatment decreased from 67% of total wastewater volumes in 2008 to less than 1% in 2011 (PA DEP 2012b). In contrast, in Colorado, surface water treatment increased from 2% of total wastewater volumes in 2008 to 11% in 2011 (COGCC 2012a). In Pennsylvania, recycling increased from 6% of total wastewater volumes in 2008 to 45% in 2011, whereas there are no data indicating any recycling occurring in Colorado. The dominant disposal method in Colorado remains injecting or evaporating wastewater fluids on site. Onsite disposal methods decreased in Colorado, managing 72% of total wastewater volumes in 2008 to 58% in 2011. In Pennsylvania, onsite well injection increased from 1% of total wastewater volumes in 2008 to 7% in 2011. Both states increased their use of centralized industrial disposal facilities between 2008 and 2011. In Pennsylvania, the use of centralized disposal facilities increased from 10% of total wastewater volumes in 2008 to 44% in 2011. In Colorado, the use of centralized disposal facilities increased from 26% of total wastewater volumes in 2008 to 31% in 2011.

Water disposal methods can change from year to year due to evolving regulations and industry experience. Data from 2008 showed a high percentage of surface water discharge for wastewaters in Pennsylvania; after 2008, there was a sharp decline. This is due to the changes to the Pennsylvania Department of Environmental Protection's (DEP) 25 Pa Code Chapter 95 Wastewater Treatment Requirements. These requirements were changed on April 11, 2009, after total dissolved solids levels were measured far above environmentally healthy levels in 2008 and 2009 (STRONGER, 2010). The high TDS was above drinking water standards in the Monongahela River. The TDS also promoted golden algae growth, resulting in higher toxicity levels in Drunkard Creek, killing over 30 different species of aquatic life. The new regulations required a maximum TDS discharge of 500 mg/L (STRONGER, 2010). This new regulation makes it uneconomical to use municipal water treatment in Pennsylvania because wastewaters can reach up to 360,000 mg/L TDS (USGS 2002b). In addition, injection has remained relatively unfavorable in Pennsylvania because the state has only eight Class II underground injection wells, three of which are commercially owned. The other injection wells are privately owned and only service the companies that own them (Phillips 2011).

Recycling operations can be more expensive than other waste management options. Recycling and reuse of water involves energy for treatment, and costs associated with storing water, transport of water, and transport and disposal of the solid wastes removed from the treated water.

In contrast, injecting wastewater into wells only involves the transport of water to an injection well and fees for the disposal. Recycling options can also be limited by high concentrations of materials that make recycling uneconomic.

3.3.2.2 Current Water-Quality Risks Resulting from Industry Activities

Risks to public water quality resulting from industry practices include risks to both surface water and groundwater sources, and they are not limited to the location of the hydraulic fracturing operation. Risks to surface and groundwater resources exist at each stage of development—well construction and hydraulic fracturing operations, chemical handling, and wastewater management.

Improper well construction or improperly plugged wells are one source of risk by which groundwater contamination can occur (PA DEP 2010b; McMahon et al. 2011). In addition to risks associated with construction integrity, risks are also associated with well durability for wells that are repeatedly hydraulically fractured. The potential exists for fracking fluids, as well as other naturally occurring substances, to reach groundwater sources if well construction or plugging operations are inadequate. The degree of risk will be dependent upon local geology, the composition of the chemicals and naturally occurring substances, and the mobility of the substances within the formation.

Another source of risk during the hydraulic fracturing operation in coalbed methane (CBM) reservoirs is the potential for the fractures to extend into aquifers or into pre-existing faults or fractures (natural or man-made) that might directly extend into aquifers. Currently, it is difficult to predict and control fracture location and lengths, and the overall risk will depend on the local geology and fracking practices used. In shale gas formations, decreasing pressure gradients and natural barriers in the rock strata serve as seals for the gas in the formation and also block the vertical migration of frack fluids (GWPC and ALL Consulting 2009). In contrast, CBM reservoirs, such as the North San Juan considered here, are mostly shallow and may also be co-located with drinking water resources. In CBM areas, hydraulic fracturing operations near a drinking water source might raise the risk of contamination of shallow water resources from hydraulic fracturing fluids (Pashin 2007; EPA 2011).

Another risk to water quality is the handling and mixing of chemicals on site. Risks include spills or leaks that might result from equipment failure, operational error, or accidents. Leaked chemicals could be released into bodies of surface water or could infiltrate groundwater resources. There have been reports of surface spills of hydraulic fracturing fluids; however, little is known about the frequency, severity, and causes of these spills (Lustgarten 2009; Lee 2011; Williams 2011). The risks to local water resources will depend on the proximity to water bodies, the local geology, quantity and toxicity of the chemicals, and how quickly and effectively clean-up operations occur.

Wastewater management practices have risks to water quality that potentially affect water resources both on and off site of the location of the shale gas development operations. Considering risks on site, spills of frac flowback or produced water could contaminate local surface and/or groundwater resources. In addition, there could be equipment failures (e.g., poorly constructed impoundments) during onsite wastewater storage prior to treatment. Potential offsite risks include spills or leakage that might occur during the transport of wastewaters to the location where they will be treated. If surface water treatment is used, there is a risk of the surface water treatment plant not having the capabilities to fully treat the wastewater before it is released back into the hydrologic cycle (Puko 2010; Ward Jr. 2010; Hopey 2011).

From 2009 to 2011, Pennsylvania had 337 reported violations that were classified as “minor effect” or “substantial effect” (NEPA 2012). Violations of these types include the release of wastes or produced water on site in amounts less than 10 barrels (420 gallons). From 2009 to 2011, Texas had 14 reported “minor effect” or “substantial effect” violations, and one reported “major effect” violation. “Major effect” violations include large spills or improperly disposed of wastes greater than 10 barrels (420 gallons), small to large spills that were moved off site and impacted a resource such as a drainage ditch or wetland, and any spill of fracturing fluid greater than 1 barrel (42 gallons). For Colorado, the only publicly accessible statistics related to violations are Notices of Alleged Violations (NOAVs). The number of NOAVs does not represent the number of violations because violations do not necessarily lead to the issuance of NOAVs. Also, when NOAVs are issued, they may cite violations of more than one rule, order, or permit condition. Colorado violations could not be acquired, and data for violations in other states were not available. More detailed information about violations in states where data are available is listed in Appendix D. Further research is needed to fully determine the severity and cause of the reported violations.

3.4 Data Availability and Gaps

Substantial gaps in data availability prevent a full assessment of risks to water resources resulting from shale gas operations. Only certain statistics are publicly available for each region, and in some regions that cross state boundaries, information is only available for the part of a play that is in one state (Table 8.)

Table 8. Overview of Data Availability

		CO	NM	PA	NY	TX	TX	LA	WY
	Risk Factor or Analysis Metric	**North San Juan**	**North San Juan**	**Marcellus**	**Marcellus**	**Barnett**	**Eagle Ford**	**Haynesville**	**Upper Green River**
1	Disposal methods/volumes	◊		◊	◊				^
1a	Fraction of water recycled	◊		◊					
2	Fresh water use	^	^	◊		^	^	◊	^
2a	*Fracturing water*	◊		◊		◊	◊	◊	◊
2b	*Source permitting*	^		◊		^	^	^	^
3	PW/FF volumes	◊		◊		^	^	^	
3a	*Injected volumes*	◊				^	^	◊	◊
4	State regulations					◊			
4a	*Rule violations*			◊					
5	Regional water use			◊					
6	Total wells			◊		^	◊		
6a	*% Horizontal*			◊			◊		
Key									
◊	Data available								
^	Partial data available								

Comprehensive analyses of water risks are hindered by a lack of reliable, publicly available water usage and management data. Data are not publicly available for many regions for total water withdrawals, total wells drilled, water recycling techniques, wastewater management, and other management practices. These data would assist in developing appropriately flexible and adaptive best management practices. Certain resources—such as the State Review of Oil and Natural Gas Environmental Regulations (STRONGER) and FracFocus—have greatly increased public access to information about risks of hydraulic fracturing; but further efforts are desired. Data collection and availability could improve with further collaboration and interaction with industry stakeholders, as well as other stakeholders.

3.5 Best Management Practices (BMP)

Various attempts have been made to define best practices for water management (e.g., IEA 2012; Energy Institute 2012; ASRPG 2012; Chief O&G 2012; SEAB 2011; API 2010). Based on these reports, the following are best practices that are generally accepted to be important for understanding and minimizing risks related to water quantity and quality:

3.5.1 Monitoring and Reporting

- *Measure and publicly report the composition of water stocks and flow throughout the fracturing and cleanup process.* There is little information on the management of fracturing water from acquisition to disposal or recycle, both in terms of quality and quantity.

- *Adopt requirements for baseline water-quality testing.* Background testing is recognized for its value, but is often not standardized. Better guidance is needed for statistically defensible testing.
- *Fully disclose hydraulic fracturing fluid additives.* Disclosure of fracturing fluid chemicals on fracfocus.org is now in place in Colorado, Wyoming, and Texas and is being considered in several other states.

3.5.2 Water Quantity

- *Recycle wastewaters.* Freshwater demand can be minimized by treatment and reuse of produced water and frac flowback. Flowback water produced in the hydraulic fracturing process is returned at relatively high flows and might contain more chemicals of concern than produced water. Optimized handling of this fluid is important for mitigating risks to water quality and quantity because it can lessen the need for transport and wastewater disposal.

3.5.3 Water Quality

- *Use a closed-loop drilling system.* In closed-loop drilling processes, contaminated water is not exposed to air or pits where it could leak, thus eliminating the storage of discarded drilling fluids in open pits at the drilling site.
- *Eliminate flowback water mixing with fresh water in open impoundments.* Disposing of untreated flowback water in reservoirs containing fresh water to be used for hydraulic fracturing increases the risk of harmful spills or leaks.
- *Use protective liners at pad sites.* The use of liners or other protective devices at pad sites can contain minor spills and prevent environmental contamination. Proper collection and disposal equipment is also important to have on site.
- *Minimize use of chemical additives and promote the development and use of more environmentally benign alternatives.* "Green" hydraulic fracturing fluid has been developed—based on fluid mixtures from the food industry—that do not impair groundwater quality in the case of an inadvertent leak or spill.

A next step in developing BMPs for reducing risks to water resources in shale gas development is to evaluate the efficacy of each of the above BMPs (Kemp 2012; Energy Collective 2012). Currently, little or no data exist that analyze the effectiveness or cost-benefit tradeoffs of these BMPs. Further examination of BMPs could assist developers in evaluating important water management questions—such as whether installing protective liners at pad sites or reducing use of chemical additives would have a greater impact on reducing risks to water resources in their regions. A first step in this direction would be to develop a methodology for quantifying and comparing current water-management practices with potential risks.

In many cases, BMPs might be more appropriate or cost-effective for certain geological conditions than others. A further area of needed research is to evaluate the extent to which certain BMPs are applicable or effective across multiple types of formations. To better address this question, researchers could engage a variety of stakeholders—including industry, regulators, researchers, environmental groups, and the public—to understand what practices are currently in use, how effective they are at reducing the risk of water impacts, and where improvements are needed.

A major challenge facing some of these BMPs is that there are no national or state-level disclosure initiatives to track or evaluate the success of their implementation. For example, it is difficult to determine how many operators are currently employing (and with what success) the widely discussed BMP to use closed-loop drilling practices because operators are not required to report this information. Absent such reporting, data collection efforts would likely require close collaboration with multiple industry partners operating in a variety of locations, and this could be time-intensive.

3.6 Summary

We used publicly available datasets to provide an initial evaluation of water risks associated with hydraulic fracturing in six natural gas plays in the United States. Data were limited in every region; continued efforts to catalogue and publish water data will improve future analyses.

Hydraulic fracturing operations have the potential to impact water resources. One of the impact risks associated with water is regional resource depletion due to the use of fresh water during hydraulic fracturing. Water-use data were collected for five of the six regions with average use per well ranging from 1.1 to 5.8 million gallons, with a multi-region average of 3.3 million gallons per well. Total water usage can be estimated by determining the average water use per well, number of wells, and recycling rate; this total freshwater demand value can be compared with estimates of local water availability. Hydraulic fracturing demands are a small fraction of total state water demands, but they can be a substantial portion of water demands in the counties in which the hydraulic fracturing operations are active. If water must be transported from off site to a hydraulic fracturing site, water quantity risks might extend to counties where hydraulic fracturing is not occurring. In all regions considered, the number of wells drilled for hydraulic fracturing has increased each year since 2009. Recycling rates have increased significantly in Pennsylvania since 2009, when the state issued new regulations regarding the treatment of wastewaters.

A second impact risk associated with water is degradation of surface and groundwater quality. Water-quality impacts are a risk during the well construction, hydraulic fracturing, mixing of chemicals, and the wastewater management of shale gas development. As noted above, hundreds of substantial or major violations have been reported that have resulted in spills of produced water, frack fluids, or chemicals. However, it is not clear if water resources have been contaminated—and if so, to what extent—or by which pathway the spills occurred.

A better understanding of the potential contamination pathways (listed here) and their impacts to water resources could assist in identifying and evaluating the phases of operation that have the highest risk of impacting water quality. Potential contamination pathways during well construction and hydraulic fracturing are improper well construction, well degradation from repeated use, lengthy fractures, and improper well plugging. Potential contamination pathways during the mixing of chemicals phase are spills, accidents, and storage equipment failures. Potential contamination pathways at the hydraulic fracturing site during the management of wastewaters are onsite storage equipment failures and spills. Additional contamination pathways and risks occur during the transport of wastewaters to disposal facilities and the potential stress put on surface water treatment plants that might not be capable of treating the types of wastes produced from hydraulic fracturing operations.

Currently, a variety of BMPs are being employed in different regions to minimize risks to water resources. However, there is uncertainty in the industry concerning BMP transferability, cost-effectiveness, and risk mitigation potential. In addition, it is unclear to what extent these BMPs are being employed by different operators. Recycling of frac flowback and produced water is an accepted recommended practice, but limited information exists regarding prevalence, methods, and costs. Except for Pennsylvania, recycling data are not available from public databases, so it is difficult to estimate how much water is being reused in these regions.

3.7 Conclusions and Next Steps

Prior efforts, in addition to with this study, have identified the variety of water-related risks and potential contamination pathways resulting from shale gas development. However, existing publicly available data are not sufficient to perform a full risk assessment on a national or regional scale. A comprehensive and actionable risk assessment would require additional analyses, including the following:

- Quantitatively assess the magnitude of the impacts of the contamination pathways discussed in this report.
- Quantitatively assess the probability that the risks discussed will occur, based on existing industry practices.
- Identify the contamination pathways and risks that, at present, are adequately or inadequately addressed by current industry practices.
- Evaluate BMPs in terms of risk mitigation potential, cost-effectiveness, regional transferability, and industry prevalence.
- Evaluate in detail the wastewater recycling practices, including estimates of current recycling rates, estimates of total potential freshwater savings resulting from recycling, and a life cycle assessment (in terms of energy inputs, emissions, and costs) to identify thresholds for deciding whether to dispose of or recycle wastewaters.

The application of systematically developed BMPs could increase the transparency and consistency by which shale gas development occurs, providing benefits to industry and interested stakeholders. Effective BMPs follow from a defined prioritization of risks in the context of other risks. Risk prioritization would be facilitated by greater availability of industry data and current practices. Further collaboration and interaction with industry, and other stakeholders could improve data collection efforts and are a first step in achieving the analysis objectives above. Lastly, water resources are just one category of risk resulting from shale gas development. Future efforts could evaluate water-related risks and BMPs alongside other risks to air, land, and community.

4 Natural Gas Scenarios in the U.S. Power Sector

4.1 Overview of Power Sector Futures

This chapter summarizes results from modeling different U.S. power sector futures. These futures assess key questions affecting today's natural gas and electric power markets, including the impacts of:

- Forthcoming EPA rules on power plants
- Decarbonization options such as a clean energy standard (CES)
- Potential improvements in key generation technologies
- Higher costs for natural gas production assumed to arise from more robust environmental and safety practices in the field
- Expanded use of natural gas outside of the power generation sector.

The simulations were done using NREL's ReEDS model, incorporating findings from Chapters 1, 2, and 3, as applicable, and looking out to the year 2050.

ReEDS is a capacity expansion model that determines the least-cost combination of generation options that fulfill a variety of user-defined constraints such as projected load, capacity reserve margins, emissions limitations, and operating lifetimes. The model has a relatively rich representation of geographic and temporal detail so that it more accurately captures the unique nature of many generation options, as well as overall transmission and grid requirements. It is a power-sector-only model, so special steps were taken to consider the feedback effects of natural gas demand in other sectors of the economy. These steps, along with additional details about the model, are more fully described in Appendix E of this report.[132]

The scenario analysis presented here is not a prediction of how the U.S. electricity sector will evolve in the future—rather, it is an exercise to compare the relative impacts of different scenarios. Three Reference scenario cases are used as points of comparison for other scenarios based on policy, business, or technology change:

1. Baseline – Mid-EUR
2. Baseline – Low-EUR, and
3. Baseline – Low-Demand.

The modeling team explored four potential policy scenarios in addition to the Reference scenario:

1. A *Coal scenario*, driven by a combination of forthcoming EPA rules, low-cost natural gas, and the age of existing coal generators. Specifically, this scenario addresses the

[132] A full description of the model is also available at: http://www.nrel.gov/analysis/reeds/pdfs/reeds_documentation.pdf.

question of what new capacity will need to be built if and when coal plants retire, and what impacts would result from proposed NSPS.

4. A *CES scenario* with carbon mitigation sufficient for the U.S. power sector to contribute its share in lowering emissions to a level that many scientists report is necessary to address the climate challenge (IPCC 2007; C2ES 2011). This simulates a CES similar to that proposed by Senator Jeff Bingaman, but analyzes impacts through 2050 (EIA 2012a).
5. An *Advanced Technology scenario* where several different generation options—nuclear, solar, and wind—achieve cheaper and thus more widespread deployment; and
6. A *Natural Gas Supply-Demand Variation scenario* for natural gas, aimed to simulate the impact of (1) steps taken to incrementally address environmental and safety concerns associated with unconventional gas production, and (2) significant growth in natural gas demand outside the power sector (Dash-to-Gas). In both cases, the incremental cost of securing natural gas for power generation results in different power sector futures over the long term.

The family of scenarios is summarized in Figure 24.

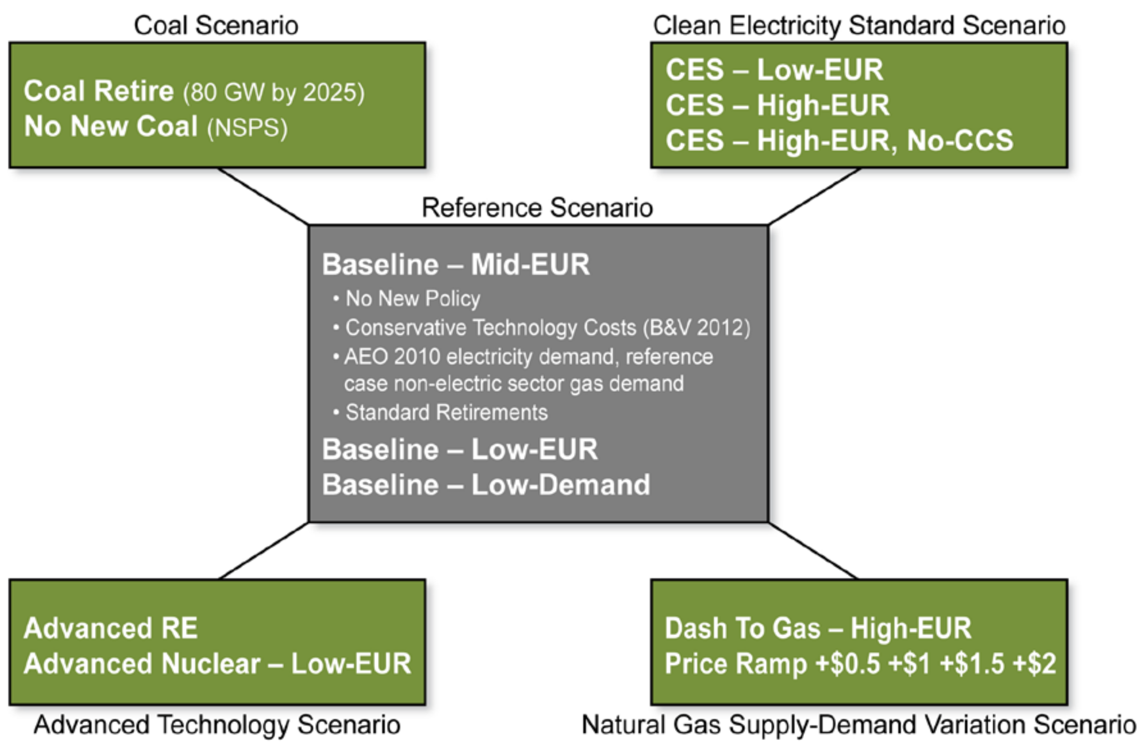

Figure 24. Scenarios evaluated in the power sector futures

4.2 Assumptions and Limitations

Technology cost and performance metrics used in ReEDS are presented in Appendix E. All costs in this study are listed in 2010 dollars unless otherwise noted.

Supply curves were developed to represent natural gas cost to the power sector and the response of this cost to increased power sector demand. The supply curves were developed based on linear regression analyses from multiple scenarios developed by the Energy Information Administration in the Annual Energy Outlook 2011 (EIA 2011).[133] The supply curves represent the price of fossil fuel to the power generators as a function of overall electric sector consumption of the fuel. In particular, as electric sector consumption increases, the marginal fossil fuel price to power generators (and all consumers of the fossil fuel) would increase. Within each year of the ReEDS optimization, the model sees this price response to demand through the linear supply curves. Three sets of supply curves were developed, representing different levels EUR[134] of natural gas. Additional detail on these supply curves is also outlined in Appendix E.

Current renewable tax incentives and state renewable portfolio standards are represented in the ReEDS model. Tax incentives include the modified accelerated cost recovery system for tax depreciation, the production tax credit for utility-scale wind technologies, and the investment tax credit for solar and geothermal technologies.[135] The tax credits are assumed to expire at their legislative end date and not be renewed. In particular, the wind production tax credit expires at the end of 2012, and the solar ITC declines from 30% to 10% in 2016. Although the solar and geothermal investment tax credits have no legislative end date, they are assumed to expire in 2030 as to not influence the long-term expansion decision of the model.

All scenarios evaluated here assume that 30 GW of coal-fired capacity will retire by 2025. The Coal scenario in Section 4.4 considers a higher level of coal retirement and has more detail on the assumed distribution of coal retirements.

ReEDS determines when new high-voltage electricity transmission infrastructure is required and tracks the costs associated with its deployment. It does not track the need to build new natural gas pipeline infrastructure, so those costs are not included in this analysis.

ReEDS is not designed to account for distributed generation; therefore, the penetration of distributed (residential and commercial) rooftop PV capacity was input exogenously into ReEDS from NREL's Solar Deployment Systems (SolarDS) model (Denholm et al. 2009). SolarDS is a market penetration model for commercial and residential rooftop PV, which takes as inputs rooftop PV technology costs, regional retail electricity rates, regional solar resource quality, and rooftop availability. In all cases, except in the Advanced Technology scenario, 85 GW of rooftop PV was assumed to come on line by 2050. This assumption was based on some of the Renewable Electricity Futures (RE Futures) Report 80%-by-2050 renewable electricity scenarios (NREL 2012).

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[133] (EIA 2011). Annual Energy Outlook 2011 scenarios are projections out to the year 2035, and these results are extrapolated to 2050 for use in the ReEDS model. A separate supply curve was developed for each year to represent changes in projected supply and demand interactions as estimated in the multiple Annual Energy Outlook 2011 scenarios. The modeling team had already commenced work by the time the 2012 edition of the Annual Energy Outlook was released, so it could not take advantage of those newer data.

[134] EUR is the amount of natural gas (or petroleum) that analysts expect to be economically recovered from a reservoir over its full lifetime. Three potential measures of EUR are used throughout this study (High, Mid, and Low) to reflect the ranges of optimism and uncertainty over unconventional natural gas availability and price.

[135] Detailed information on these tax incentives can be found on the Database of State Incentives for Renewables and Efficiency at: http://www.dsireusa.org/.

4.3 Reference Scenario

Three different baseline cases were evaluated in the Reference scenario:

- Baseline – Mid-Estimated Ultimate Recovery (Mid-EUR) case, with average power demand growth and a moderate outlook for natural gas prices
- Baseline – Low-EUR case reflecting the potential for more limited—and hence, more expensive—natural gas
- Baseline – Low-Demand case with Mid-EUR expectations. Low demand for electricity could be the result of continued economic stagnation (low gross domestic product [GDP] growth) or successful efforts to curb energy demand through energy efficiency, demand response, smart grid, and other programs to reduce the need for new electricity supply.

A Baseline – High-EUR case was not considered in this family in order to keep the number of results manageable. As noted previously, the Reference scenario is not a prediction of the future U.S. electricity mix *per se*, but instead, it serves as a point of comparison for the other scenarios. Each baseline case in the Reference scenario is summarized in Table 9.

Table 9. Description of Reference Scenario

Case Name	Assumption for Future Electricity Demand	Assumption for Estimated Ultimate Recovery (EUR)
Baseline – Low-EUR	Standard Growth (EIA 2010)	Low-level
Baseline – Mid-EUR	Standard Growth (EIA 2010)	Mid-level
Baseline – Low-Demand	Low Growth (NREL 2012)	Mid-level

Figure 25 and Figure 26 present the projected growth of electric generating capacity and generation for each of the three baseline cases. In the Baseline – Mid-EUR case, total capacity grows from roughly 1,000 GW in 2010 to just over 1,400 GW in 2050. While nuclear and coal capacity decrease as a result of net aged-based retirements, natural gas combined-cycle and natural gas combustion-turbine capacities nearly double, with especially strong growth expected after 2030 when nuclear and coal retirements accelerate. On-shore wind capacity grows steadily from roughly 40 GW in 2010 to nearly 160 GW in 2050, representing about 3 GW of new additions each year on average over the period—a significant reduction from deployment in recent years. In all three baseline cases, oil and gas steam-turbine capacity is fully retired by roughly 2035 due to their low efficiency. Nuclear capacity also declines in all three baseline cases beginning around 2030 as plants reach the end of their operational lifetime and licensing arrangements, and no new plants are built due to uncompetitive economics. As noted above, rooftop PV is not endogenously calculated by ReEDS, but was exogenously assumed for each of the scenarios and baseline cases. Under the technology cost assumptions used, utility-scale PV showed more limited growth compared to natural gas and wind, reaching roughly 10 GW by 2030 and 20 GW by 2050.

The Baseline – Low-EUR case considers a future in which natural gas is less abundant, and thus more expensive, than the Baseline – Mid-EUR case. The primary impact in such a future is less natural gas capacity and more coal and wind. For example, in this baseline case, the cumulative installed wind capacity reaches about 200 GW by 2050.

In the final Baseline – Low-Demand case, growth in natural gas capacity is affected the most, although wind and coal also see little to no growth.

Considering the associated generation futures in these three baseline cases may be more instructive because capacity alone does not indicate how power plants are operated. Generation from natural gas combined-cycle plants doubles over the 40-year period, growing especially rapidly starting around 2030 because it is used to make up for the retired nuclear and coal generation (see Figure 26). Generation from natural gas combustion-turbine is almost too small to see in these charts, but plays an important role in meeting peak load needs. In the Baseline – Low-EUR case, new coal capacity is added and its generation plays a growing role in meeting power demand after 2030. This new coal is not needed in a low-demand future, and little new wind or other renewable energy generation is needed either.

Figure 27 presents four key metrics for the baseline family of cases. First, natural gas consumption rises 2.5-fold from 2010 to 2050 in the Baseline – Mid-EUR case, but still nearly doubles in the other two cases. Second, average real natural gas prices that generators pay are expected to nearly double by 2050 in the Baseline – Mid-EUR case,[136] while the Baseline – Low-EUR case would see higher prices throughout the period. A Baseline – Low-Demand future will put far less pressure on natural gas prices because they peak at just over $8/MMBtu in 2050. Third, CO_2 emissions from the power sector are expected to remain relatively flat throughout the period. In the Baseline – Low-Demand case, emissions decline significantly as existing coal is replaced with natural gas. Finally, average real prices paid for retail electricity grow steadily through 2050 to roughly $130/MWh in the Baseline – Mid-EUR and Baseline – Low-EUR cases, but are about $15/MWh cheaper in the Baseline – Low-Demand case.

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[136] Prices to power generators are higher than well head prices by approximately $1/MMBtu, but vary by region.

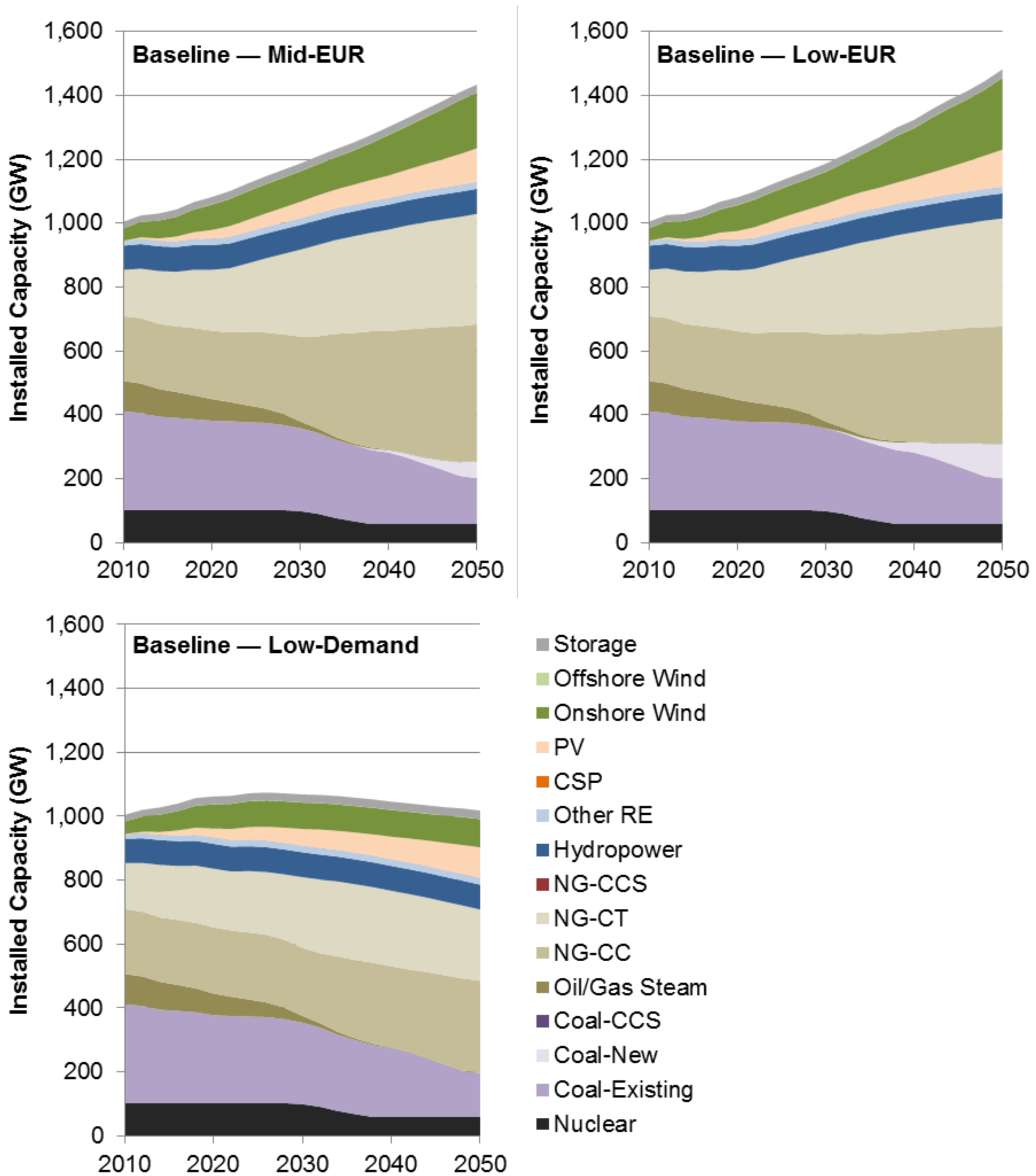


Figure 25. Projected capacity in the Reference scenario, 2010–2050, for Baseline – Mid-EUR, Baseline – Low-EUR, and Baseline – Low-Demand cases

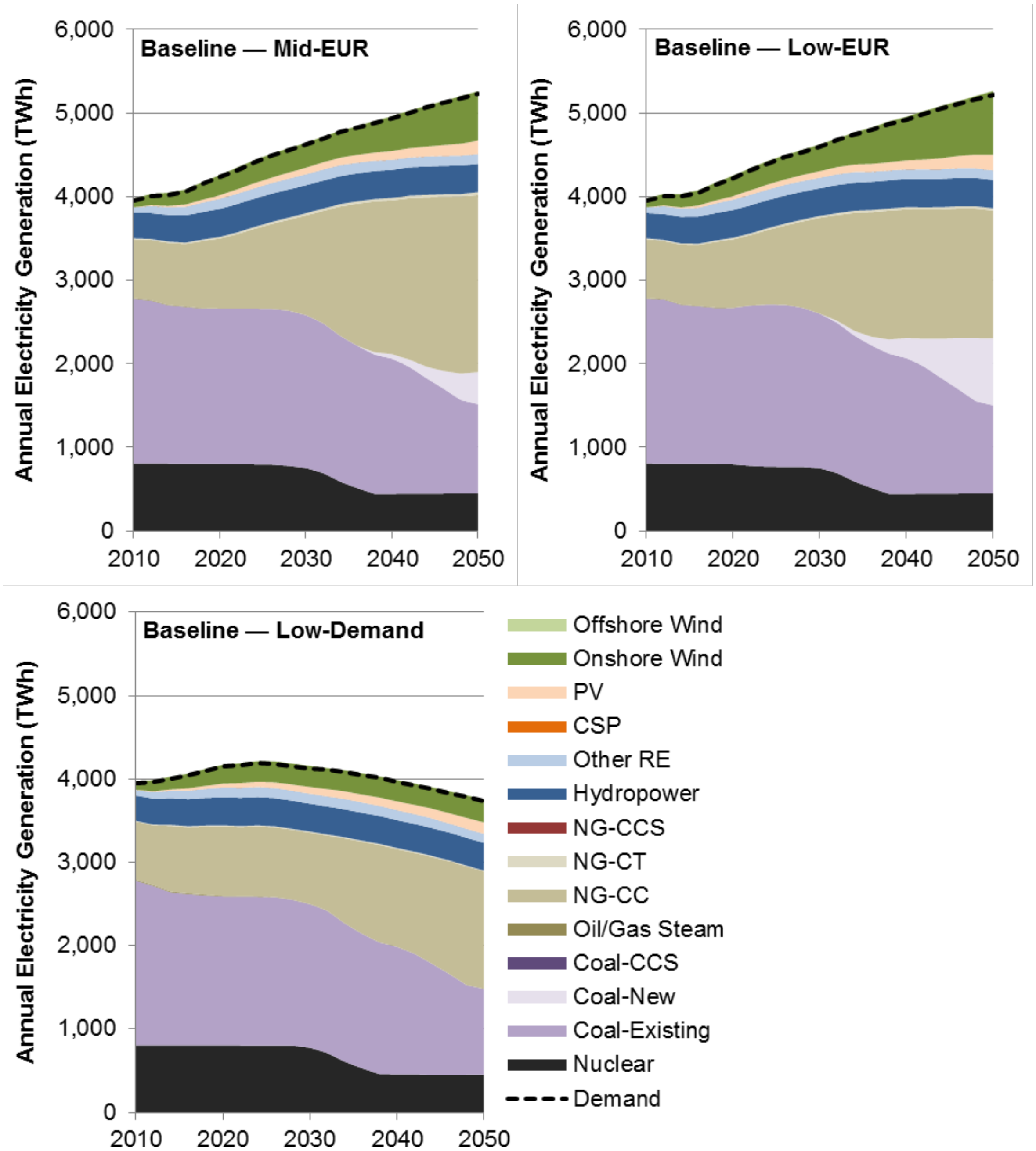


Figure 26. Projected generation in Reference scenario, 2010–2050, for Baseline – Mid-EUR, Baseline – Low-EUR, and Baseline – Low-Demand cases

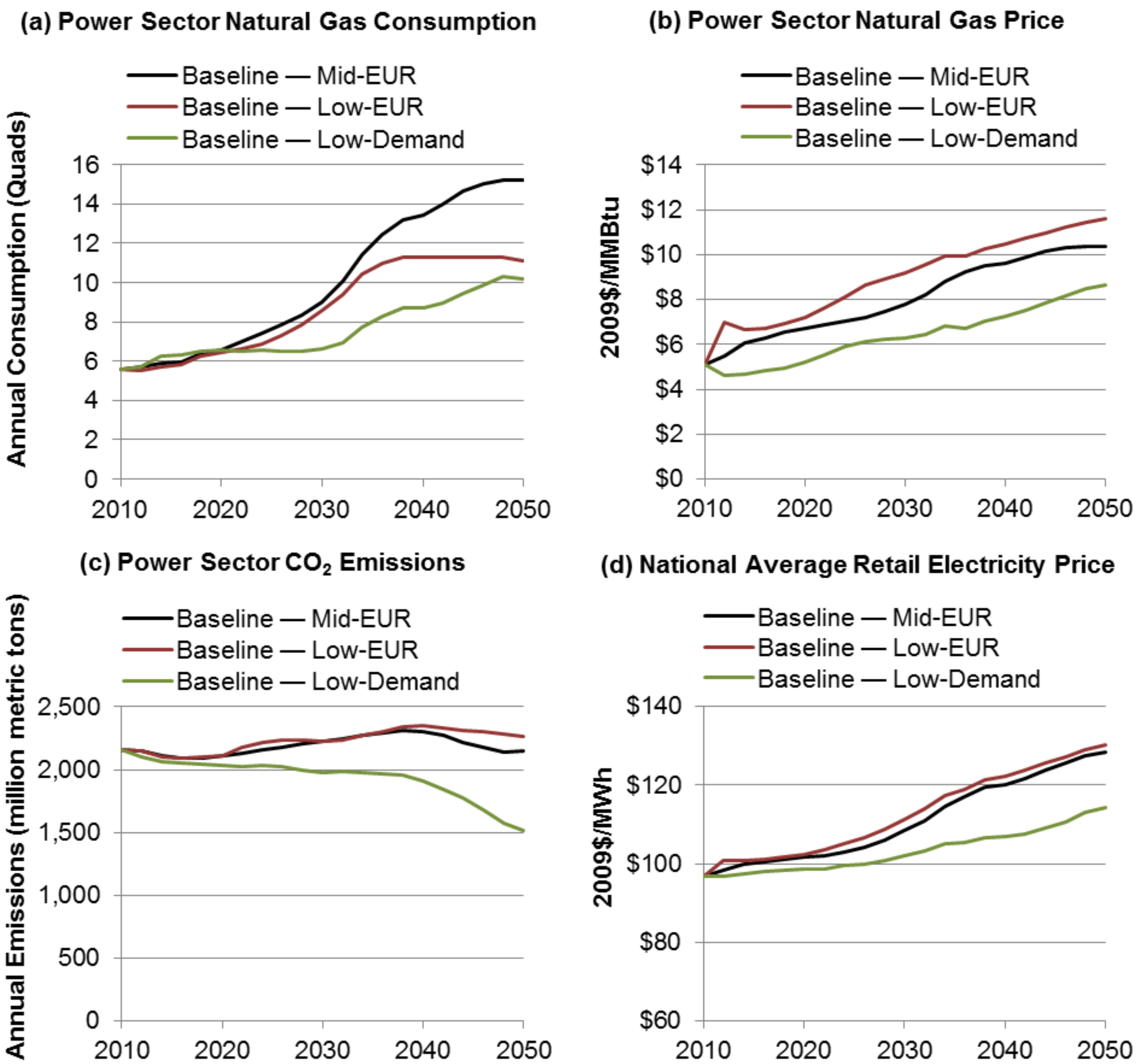


Figure 27. Selected metrics for the Reference scenario, 2010–2050

4.3.1 Implications of Reference Scenario

An electric power future as envisioned in the Baseline – Mid-EUR case would include rapid growth in natural gas generation and less reliance on coal and nuclear power. In effect, natural gas and coal swap positions compared to their historical levels. One concern in such a future is that if volatility returns to natural gas prices after additional new capacity is built—and coal plants are already retired—the economy will be more directly exposed to fluctuating electricity prices. Careful consideration of the benefits and costs of such a shift in generation diversity is warranted.

Although CO_2 emissions do not grow signficantly in such a future, they also do not begin to transition to a trajectory that many scientists believe is necessary to avoid dangerous impacts from climate change. GHG emission reductions of up to 80% by 2050 (compared to 2000 levels) are considered necessary by most climate scientists to stabilize atmospheric concentrations of GHG and prevent the most serious impacts from a changing climate (IPCC 2007). The Reference scenario results do not put the U.S. power sector on a trajectory to meet this target.

A low power demand future, consistent with recently observed trends,[137] may provide greater generator diversity and prevent a potential over-reliance on natural gas. This Baseline – Low-Demand case also has lower emissions and price impacts, although growth in low-carbon energy deployment slows significantly.

4.4 Coal Scenario

This scenario considers two cases:

- *Coal Plant Retirements case:* The impact of retiring an aggregate 80 GW of coal-fired generation by 2025
- *No New Coal without CCS case:* The impact of not allowing any new coal-fired generating capacity to be built unless it is equipped with CCS technology, which is similar to the proposed EPA New Source Performance Standard rule[138]

As noted previously, the baseline in all scenarios assumes that 30 GW of coal will retire by 2025 due to endogenous age-based rules, plus additional retirements of other aging non-coal-fired plants. Many studies have been published that estimate the potential impact of the forthcoming EPA rules—and increasingly, low-priced natural gas—that are assumed to drive the decision to retire existing plants (Macedonia et al. 2011). A more fundamental reason for retirement may be that about two-thirds of the U.S. coal fleet was built in the 1970s or before (SNL 2011). The two cases evaluated in the Coal scenario are summarized in Table 10. Text Box 2 provides additional information on the EPA rules.

Table 10. Description of Coal Scenario

Case Name	Coal Capacity Retired by 2025 (GW)	Assumption for natural gas Estimated Ultimate Recovery (EUR)
Coal Plant Retirements	80	Mid-level
No New Coal without CCS	30 (same as Reference)	Mid-level

As noted previously, there are two forthcoming EPA rules that are likely to cause many older coal-fired plants to consider either costly retrofits to control pollution or retirement as a more economic solution: the Cross-States Air Pollution Rule and the Mercury and Air Toxics Standard. Two other EPA rules are under development that would attempt to address concerns about (1) water intake structures for cooling purposes at most power plants (the 316(b) rule) and (2) disposal of coal combustion residuals, also known as the coal ash rule.

[137] Total net power generation in the U.S. peaked in 2007, according to EIA statistics, and has not yet returned to pre-recession levels (EIA 2012c).
[138] For additional background on the proposed NSPS ruling, see http://epa.gov/carbonpollutionstandard/.

Text Box 2: Coal Plant Retirements, EPA Rules, and Low-Price Natural Gas

Over the past few years, power sector analysts have debated the impact of new and forthcoming EPA rules on coal plant retirements. These rules include, but are not limited to, the following:

- Cross-States Air Pollution Rule
- Mercury and Air Toxics Standard
- Clean Water Act Section 316(b) cooling water intake structure ruling
- Coal Combustion Residual Rule.

Selected highlights of the rules include:

Cross-States Air Pollution Rule: Limits fine particulate emissions and ozone *transport* in many eastern state power plants by reducing SO_x and NO_x emissions. Compliance options include the installation of low-NO_x burners, catalytic reduction, and scrubbers. The U.S. Court of Appeals struck down this rule in August 2012, and an earlier version known as the Clean Air Interstate Rule will be enforced in its place until EPA redesigns it.

Mercury and Air Toxics Standard: Reduces mercury, acid gases, trace metals and organics emissions at power plants by requiring maximum achievable control technology. Compliance options include scrubbers, filters, and activated carbon injection. Final rule released, and a 3-year compliance period is under way, although legal challenges are also mounting.

316(b): Protects fish and aquatic life from entrapment or entrainment in cooling-water intake structures at power plants. Compliance options include screens, barriers, nets, or cooling towers. The date for issuing the final rule was recently pushed back from July 2012 to June 2013.

Coal Combustion Residual Rule: Establishes standards to manage risk of post-combustion coal waste from power plants. There are two regulatory options under consideration by EPA with different ramifications on power generation cost and impact.

Dozens of studies have been conducted to estimate the impact of these rules on power generators, although most were conducted before the rules were finalized and natural gas prices plummeted in early 2012. Relatively straight-forward financial analysis can be used to determine if it is better to retrofit a power plant so that it can comply with the new rule or retire it. However, real-world decision-making depends on a host of other factors—including future market outlook and plans, portfolio risk management, potential carbon regulations, and reliability assessments.

Some studies anticipated relatively minor impacts from plant retirements (5–20 GW by 2020) (EIA 2011; BPC 2011), whereas others forecast major potential impact and reliability concerns (30–75 GW by 2020) (EEI 2011; CERA 2011; NERA 2011). As of early 2012, about 35 GW of coal-fired generators had already announced that they would retire before 2020. At the same time, as natural gas prices plummeted through 2011 and 2012, generators ramped up operation of natural gas combined-cycle units and scaled back on use of coal generation.

The fuel switching that has already occurred primarily due to low gas prices is equivalent to about 60 GW of coal-fired capacity, although this calculation assumes the coal plants are operated infrequently (32% capacity factor). Most of the oldest coal generators in the U.S. fleet are operated infrequently and have fewer pollution controls. Although fuel switching is a voluntary decision by power generators—and hence, optimized to maximize profits in most cases—the impact of the forthcoming EPA rules will apply different decision-making criteria on top of the inexpensive natural gas driver. Thus, many of the studies conducted to assess the impact of coal plant retirements may need to be redone to account for both drivers of changing generation.

Although most existing studies have anticipated anywhere from 20 to 70 GW of coal retirements by 2020 due to these rules, natural gas price forecasts have fallen below levels that many of the studies used to evaluate the retrofit-retirement decision. The level chosen for this study, 80 GW, is based on these lower natural gas prices and a longer time horizon (2025). *Where* the retirements occur is another important assumption because it will impact whether or not new plants or transmission lines need to be built to replace the lost generation, or if existing natural gas combined-cycle plants can be operated more frequently to meet the load. The retirement distribution chosen was based mainly on the age of existing coal plants and the degree to which they had already installed pollution control devices such as activated-carbon injection and flue-gas desulfurization. Figure 28 displays where existing coal plants were retired, and shows the percentage of coal capacity that is assumed to shut down in each balancing area.

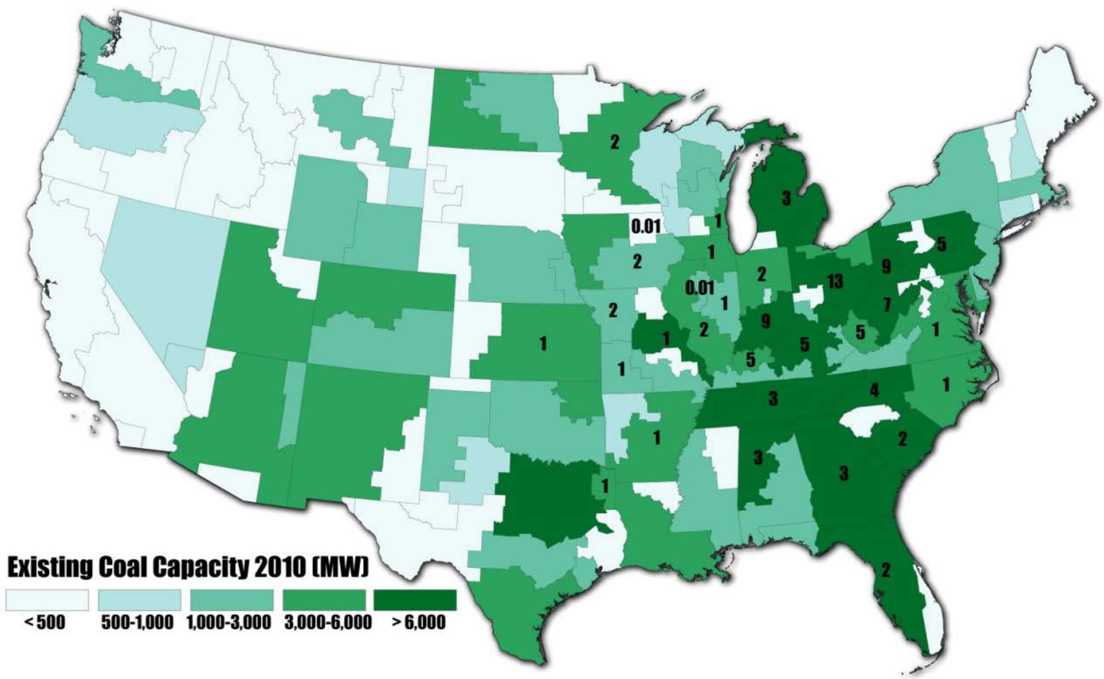


Figure 28. Assumed distribution of retirements in the Coal scenario by percentage of total coal capacity retired in 2025 in each balancing area of ReEDS

The impacts of the two coal cases are summarized in Figure 29 for the years 2030 and 2050. In the Coal Plant Retirements case (where a net 50 GW of additional retirements are seen, compared to the baseline in 2025), most of the retired coal in 2030 is replaced with natural gas combined-cycle, although some additional new wind generation is also added. In the No New Coal without CCS case, there is no difference from the Baseline – Mid-EUR through 2030 because no new coal plants were built by then in the baseline. Cumulative CO_2 emission savings are significant in the Coal Plant Retirements case: 3,300 million tons of CO_2 between 2011 and 2050, even if annual reductions are more modest (see Figure 30). The impact of retirements on average real electricity prices is also modest.

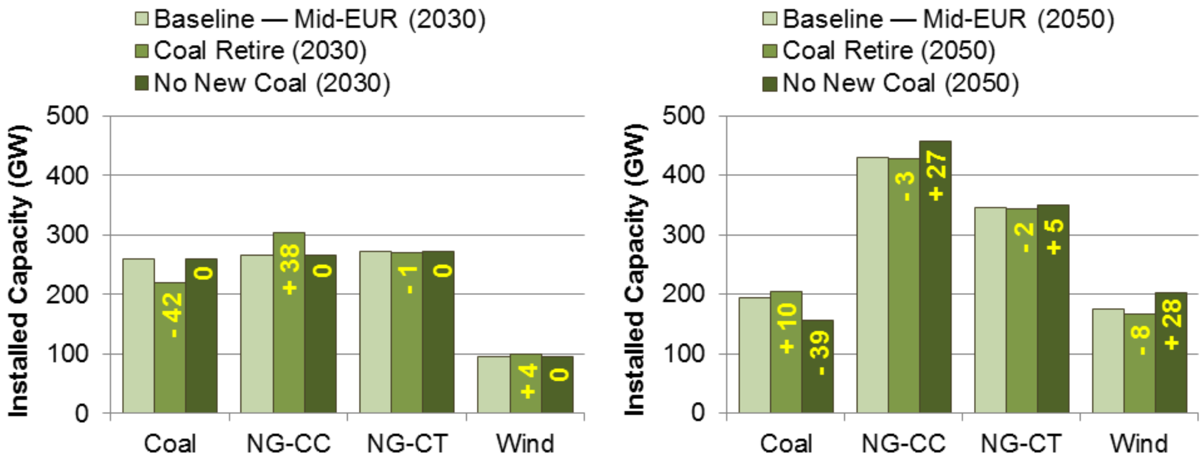


Figure 29. Impacts of coal plant retirements and no new coal without CCS compared to the baseline for 2030 and 2050

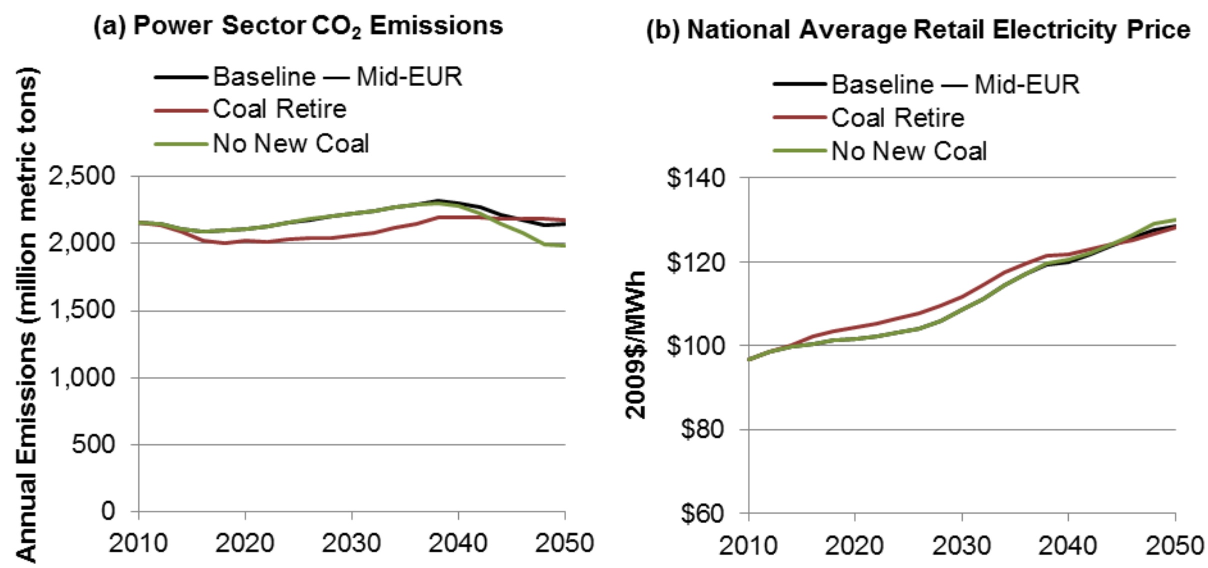


Figure 30. Selected metrics for the Coal cases, 2010–2050

4.4.1 Implications of Coal Scenario Findings

Coal retirements are replaced on a nearly one-to-one basis with natural gas, although wind plays a small role in the early years. In later years, more new coal is built, compared to the baseline, and less wind. In aggregate, however, coal retirements lead to a notable reduction in cumulative CO_2 emissions at relatively modest cost. Initial statistically based analysis does not indicate any difficulty in maintaining adequate reserve margins needed for reliability purposes, although this evaluation is done at a relatively coarse level. A more detailed dispatch model would be required for realistic evaluation of grid reliability issues in such a coal retirement case.

The No New Coal without CCS case, intended to simulate the NSPS, has little impact in early years, but does prevent the construction of new coal after 2030. Compared to the Reference scenario, where new coal does come on line after 2030, the No New Coal without CCS case does not have any new coal coming on line through 2050 because CCS is not an economic option. In this case, natural gas combined-cycle and wind contribute equally to replace what coal would have been built in the baseline.

4.5 Clean Energy Standard Scenario

After cap-and-trade legislation failed to pass the U.S. Senate in 2010, CES became the preferred vehicle for those decision makers seeking to mitigate GHG emissions in the U.S. power sector.[139] A CES sets targets for the sale of qualifying clean energy generation over time, similar to a renewable portfolio standard,[140] but awards credits roughly based on the relative carbon weighting of emissions compared to standard coal-fired generation (EIA 2012a). In this analysis, new nuclear and renewable generators receive 100% crediting because they have no burner-tip emissions; natural gas combined-cycle generation receives 50% crediting when used without CCS and 95% crediting with CCS; and coal receives 90% crediting, but only with CCS. This analysis follows the current CES legislation under discussion in Congress[141] calling for an 80% clean energy target in 2035, but extends the target to reach 95% by 2050.

Full life cycle GHG emission values could be used in the CES crediting, rather than the current burner-tip estimates, to provide a more representative picture of climate impacts. As discussed in Chapter 1, the current understanding of the full life cycle emissions of unconventional gas is not significantly different from the values noted above; therefore, this analysis does not attempt to use them. As additional information becomes available, however, follow-on research could evaluate the impacts of different crediting values on the long-run evolution of the U.S. power sector.

Three separate CES cases are considered here:

- CES – High-EUR case
- CES – High-EUR case where CCS is not available, either for technical, economic, or social reasons
- CES – Low-EUR case.

Table 11 summarizes the three cases evaluated in the CES scenario.

Table 11. Description of CES Scenario

Case Name	Is Carbon Capture and Sequestration Available/Economic?	Assumption for Estimated Ultimate Recovery (EUR)
CES – High-EUR	Yes	High-level
CES – High-EUR, without CCS	No	Mid-level
CES – Low-EUR	Yes	Mid-level

[139] Three Senate leaders have put forth CES legislation since then: Senator Lindsay Graham (SC), Senator Dick Lugar (IN), and Senator Jeff Bingaman (NM).
[140] For more background on renewable portfolio standards and clean energy standards, see (C2ES 2012).
[141] On March 1, 2012, Senator Jeff Bingaman introduced the Clean Energy Standard Act of 2012. More information on the bill is available at: http://www.energy.senate.gov/public/index.cfm/democratic-news?ID=67e21415-e501-42c3-a1fb-c0768242a2aa.

Figure 31 presents the impacts of the three CES cases on generation through 2050. In the early years before 2030, natural gas replacing coal is the primary contributor to meeting the rising CES targets. Beginning around 2030, however, natural gas is no longer able to contribute to meeting the target without CCS because it receives only 50% crediting toward the target. Instead, coal with CCS, wind, and natural gas with CCS are the next-cheapest options in the CES – High-EUR case. If CCS is not available (CES – without CCS), wind generation is the next-cheapest alternative to take its place. In such a case, renewable energy sources contribute about 80% of total generation by 2050.[142]

A CES power future with more costly natural gas (CES – Low-EUR) would result in less natural gas generation, more solar and wind, and reliance on coal CCS rather than gas CCS compared to the CES – High-EUR case.

[142] NREL recently published the RE Futures study that evaluates many of the technical issues and challenges of operating the grid with such high percentages of renewable energy. See NREL (2012) for more detail.

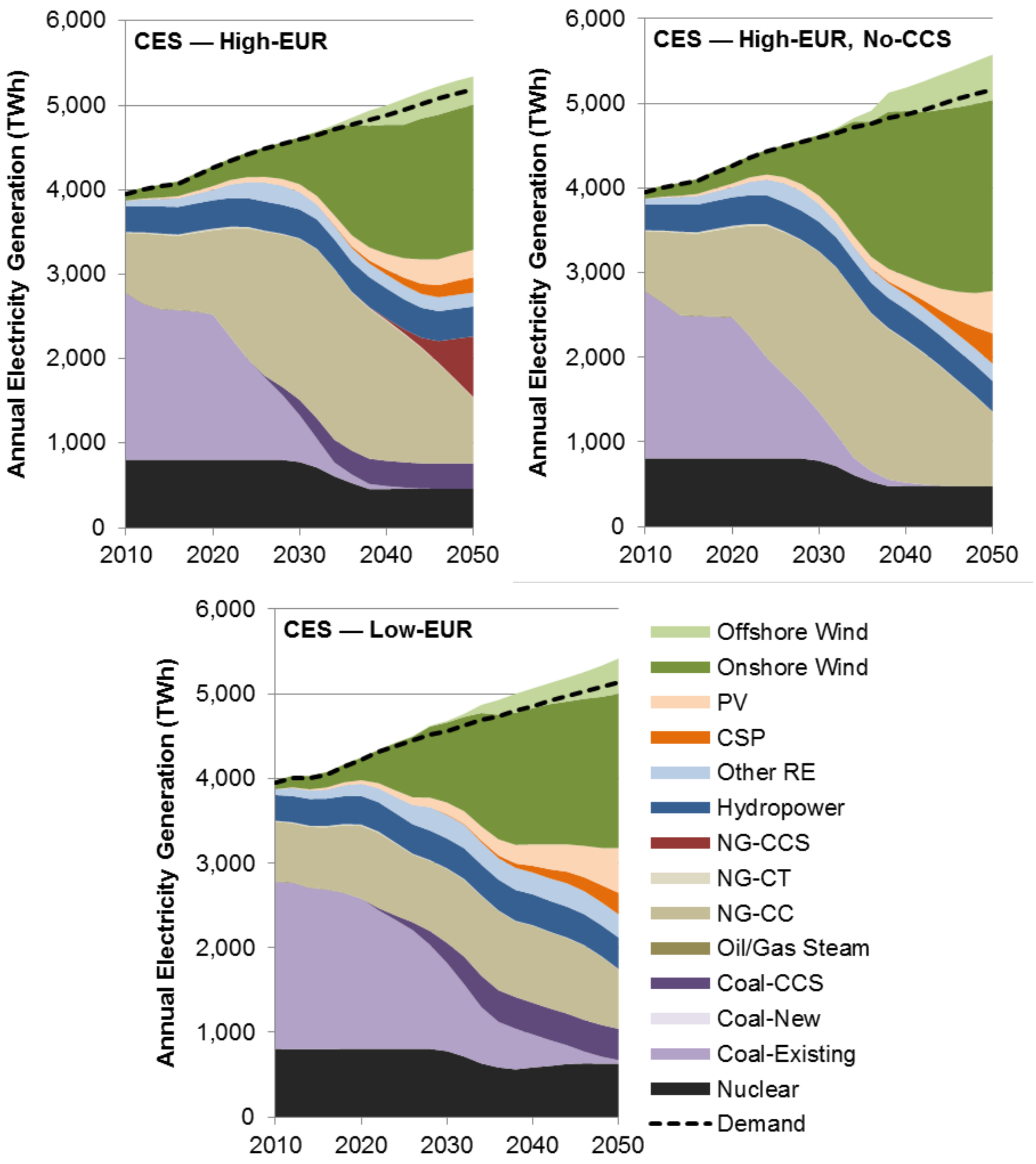


Figure 31. Projected generation in CES scenario, 2010–2050 for CES – High-EUR, CES – High-EUR, without CCS; and CES – Low-EUR cases

The amount of natural gas used in the CES scenario varies significantly by case, as shown in Figure 32. In all cases, however, it peaks around 2030, and prices remain lower than the Baseline – Mid-EUR case through 2050. Power sector gas demand temporarily falls after 2030 in the CES – High-EUR case, but begins to climb again around 2040 as natural gas CCS becomes an economic contributor to the CES target. When CCS is not available, natural gas consumption continues to decline and is back at 2010 levels by 2050. In the CES – Low-EUR case, natural gas usage remains muted throughout the scenario lifetime as other options meet the target more economically. Average real electricity prices would increase compared to the Baseline – Mid-EUR case beginning in roughly 2020 and settle at levels between 6% and 12% higher by 2050.

By 2050, CO_2 emissions from the U.S. power sector decline by more than 80% in all CES cases compared to the baseline. Coal generation without CCS has disappeared by that time in all cases. The power sector would be on a trajectory in all CES cases to achieve that sector's contribution to carbon mitigation commensurate with levels the Intergovernmental Panel on Climate Change deems necessary to stabilize atmospheric concentrations of greenhouse gases (IPCC 2007) at a level that could avoid the most dangerous aspects of climate change.

Because the CES cases project a very large build-out of wind power, ReEDS tracks the amount of new transmission lines needed to deliver power from where it is generated to where it is used. The estimated costs of building this new transmission infrastructure are included in the capacity analysis. Figure 33 presents a geospatial map of where new transmission lines would be required through 2050. The vast majority of this new wind generation would be constructed in the Midwestern states for use throughout the Eastern Interconnect. Smaller quantities would be built in the Western and Electric Reliability Council of Texas (ERCOT) Interconnects. The greatest amount of transmission is needed when CCS is not available, and wind must play an even larger role. In this case, more than twice the amount of transmission, as measured in million megawatt-miles of capacity, would be needed compared to the CES – High-EUR case in 2050 (or six-times the amount as the Baseline – Mid-EUR case).

4.5.1 Implications of CES Scenario

The CES options analyzed here indicate that the U.S. power sector could achieve significant decarbonization by 2050 at relatively modest economic costs, although barriers to building sufficient transmission may be formidable (NREL 2012). About six times more transmission is needed in the CES – without CCS case than in the Baseline – Mid-EUR case by 2050, and three times as much in the CES – High-EUR case. A greater diversity of power generation is achieved when CCS is available and economic for use on coal or gas plants. Heavy reliance on the need for transmission is also lessened when CCS is available. Additional research should be considered to evaluate potential natural gas infrastructure barriers in such a scenario of high variable renewable energy generation.

In all CES cases, large quantities of variable renewable energy are supported and firmed by flexible natural gas generators. Natural gas generators help enable a power generation mix that relies heavily on variable renewable technologies such as wind and solar.

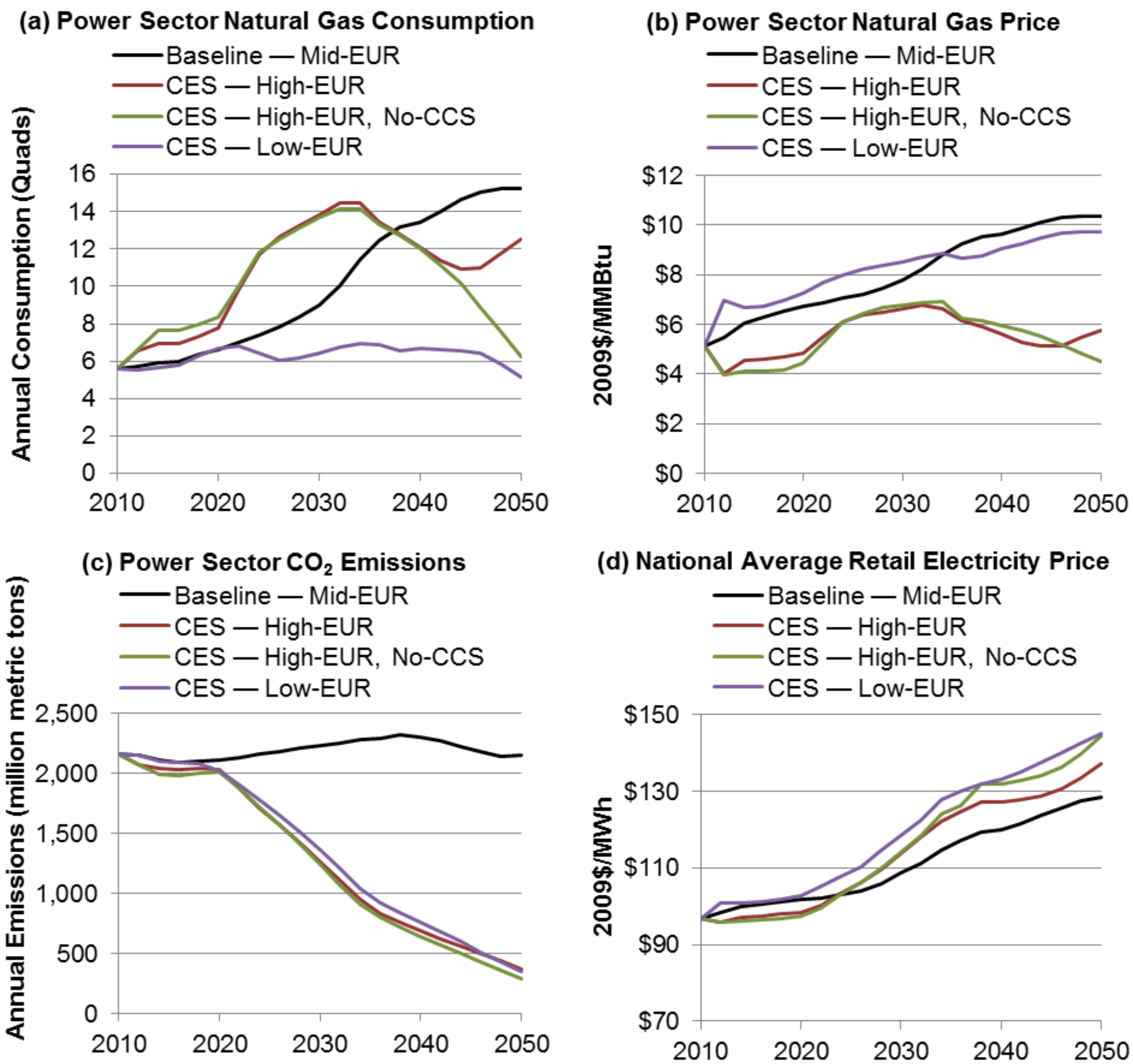
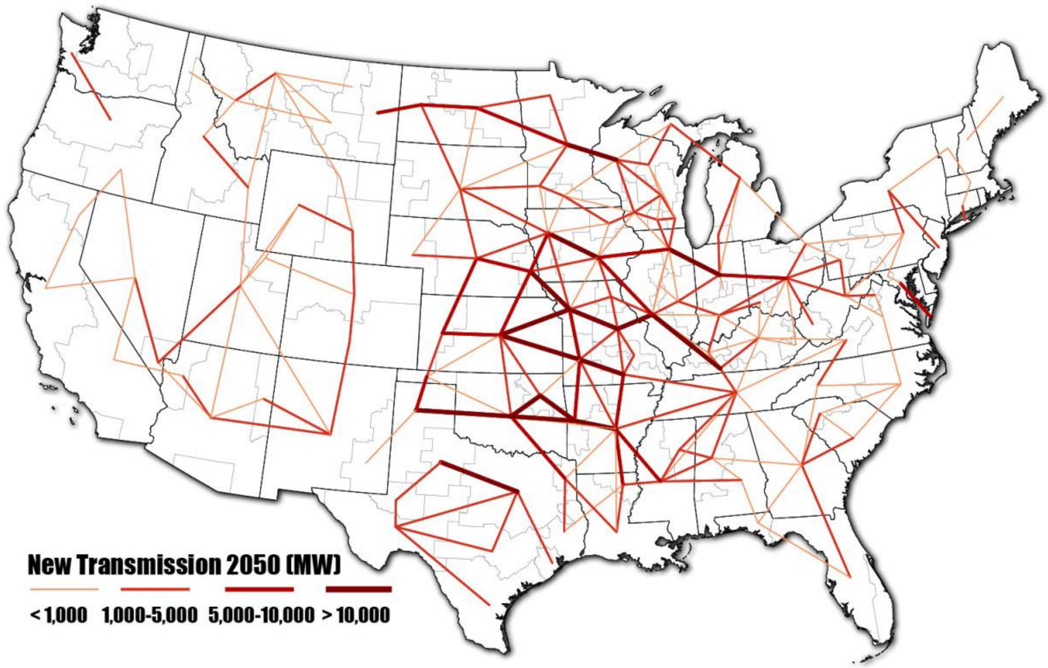


Figure 32. Selected metrics for the CES scenario, 2010–2050



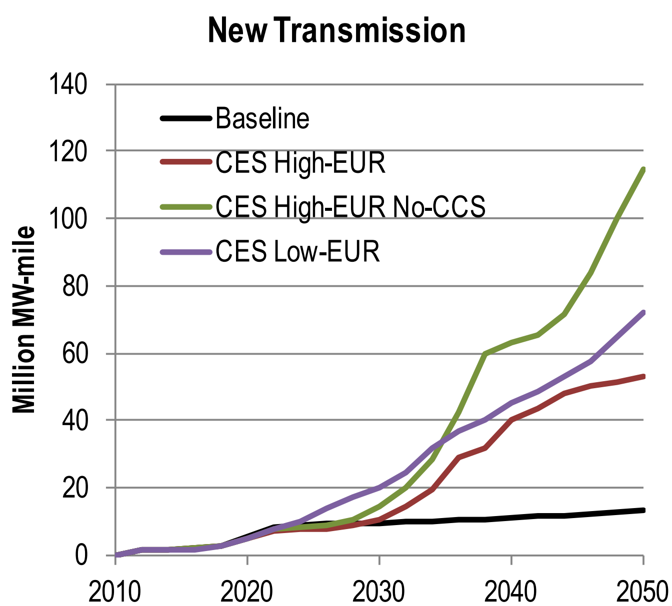


Figure 33. Map of new transmission required by 2050 in the CES – High-EUR case, and measures of new transmission needed in all cases, 2010–2050

4.6 Advanced Technology Scenario

The Advanced Technology scenario considers additional progress in the evolution of cost and performance metrics of certain generation options compared to the Baseline – Mid-EUR case. Two cases are considered here:

- *Advanced Nuclear:* A 50% reduction in the capital costs of nuclear generation by 2020. This scenario also uses a Low-EUR assumption for natural gas.
- *Advanced Renewable Electricity (RE):*[143] Capital costs for utility-scale solar PV, concentrating solar power (CSP) with thermal storage, and wind are assumed to decline, as shown in Table 12. In addition, improvements in performance of advanced RE technologies are assumed to be more significant, as shown in Table 13 (e.g., in 2050, Class 5 wind is assumed to have an annual capacity factor of 46% compared with 43% in the baseline). CSP is assumed to have the same performance as in the baseline, but with towers available at an earlier time (2015 instead of 2025), resulting in higher performance earlier. Furthermore, distributed PV was exogenously input and assumed to reach 240 GW of capacity by 2050,[144] compared to 85 GW in the baseline. This case uses a Mid-EUR natural gas assumption.

Table 12. Assumed Reductions in Capital Costs for the Advanced Technology Scenario

	2020 ($/kW)	2050 ($/kW)
Advanced Nuclear	6,200 → 3,100	6,200 → 3,100
Advanced On-shore Wind	2,012 → 1,964	2,012 → 1,805
Advanced PV	2,550 → 2,213	2,058 → 1,854
Advanced CSP	6,638 → 4,077	4,778 → 2,982

Table 13. Assumed On-shore Wind Improvements in Capacity Factors for the Advanced Technology Scenario

	Class 3	Class 4	Class 5	Class 6	Class 7
2020	0.33 → 0.38	0.37 → 0.42	0.42 → 0.45	0.44 → 0.48	0.46 → 0.52
2050	0.35 → 0.38	0.38 → 0.43	0.43 → 0.46	0.45 → 0.49	0.46 → 0.53

Table 14 summarizes the major assumptions used in the Advanced Technology scenario.

[143] Advanced RE capital costs and performance improvements were taken from the RE Futures report (NREL 2012), evolutionary technology improvement (RE-ITI) cost projection.
[144] This projection is based on the SunShot Vision Report (DOE 2012).

Table 14. Description of Advanced Technology Scenario

Case Name	Cost Assumption	Assumption for Estimated Ultimate Recovery (EUR)
Advanced Nuclear	Nuclear capital costs decline by 50% in 2020 compared to the baseline scenario.	Low-level
Advanced RE	Wind, PV, and CSP capital costs decline as shown in Table 12. Performance improvements as described above and shown in Appendix E.	Mid-level

The impact of potential improvements in these two categories of technology is shown in Figure 34. The primary impact in the Advanced Nuclear case is that enough new nuclear generation is built to offset the decline in age-based retirements by the end of the modeling period.[145] Additionally, because this case assumes a Low-EUR for natural gas (and thus, higher prices), some new coal plants are also built beginning in 2030 to meet load. The new coal plants largely offset the carbon abatement that otherwise would have occurred due to the new nuclear generation. Retail prices are also higher during most of the reporting period because the Low-EUR assumption was made (see Figure 35).

In the Advanced RE case, wind and solar generation expands considerably compared to the Reference scenario. In the case of wind, this illustrates the sensitivity of potential expansion because the assumed cost reductions and performance improvements were relatively modest. Growth in utility-scale PV capacity is substantial in this case, while actual generation increases more modestly due to the relatively low capacity factor that solar achieves. By 2050, CO_2 emissions decline by a little more than one-quarter compared to the baseline, while retail electricity prices are also slightly lower due to the assumed reduction in cost for RE technologies (Figure 35).

4.6.1 Implications of the Advanced Technology Scenario Findings

Under the assumptions used in this analysis, nuclear generation does not become cost competitive with other options until capital costs decline by roughly one-half from today's level and natural gas prices are assumed to be relatively high (Low-EUR). Even under the cost assumptions used in the Advanced Nuclear case, new coal was still competitive with the cheaper nuclear, offsetting some of the carbon advantages of nuclear. Despite these apparently high hurdles, breakthroughs in advanced nuclear designs are possible (OECD 2011; Martin 2012) and could contribute meaningfully to a more diverse and energy-secure power future in the United States.

Even modest reductions in capital costs for renewable energy technologies can have significant impact on their competitiveness compared to baseline assumptions. Wind power appears particularly sensitive to assumed reductions in capital cost and performance improvements, expanding nearly 100% compared to the baseline with capital cost reductions of about 10%. Similar reductions in utility PV capital costs lead to near-identical impacts in the deployment of that technology, whereas a greater reduction in CSP capital costs would be needed to see a large expansion in the role of that technology.

[145] This case was also evaluated under High-EUR and Mid-EUR gas futures, but nuclear was not competitive in that environment, so only the Low-EUR results are shown here.

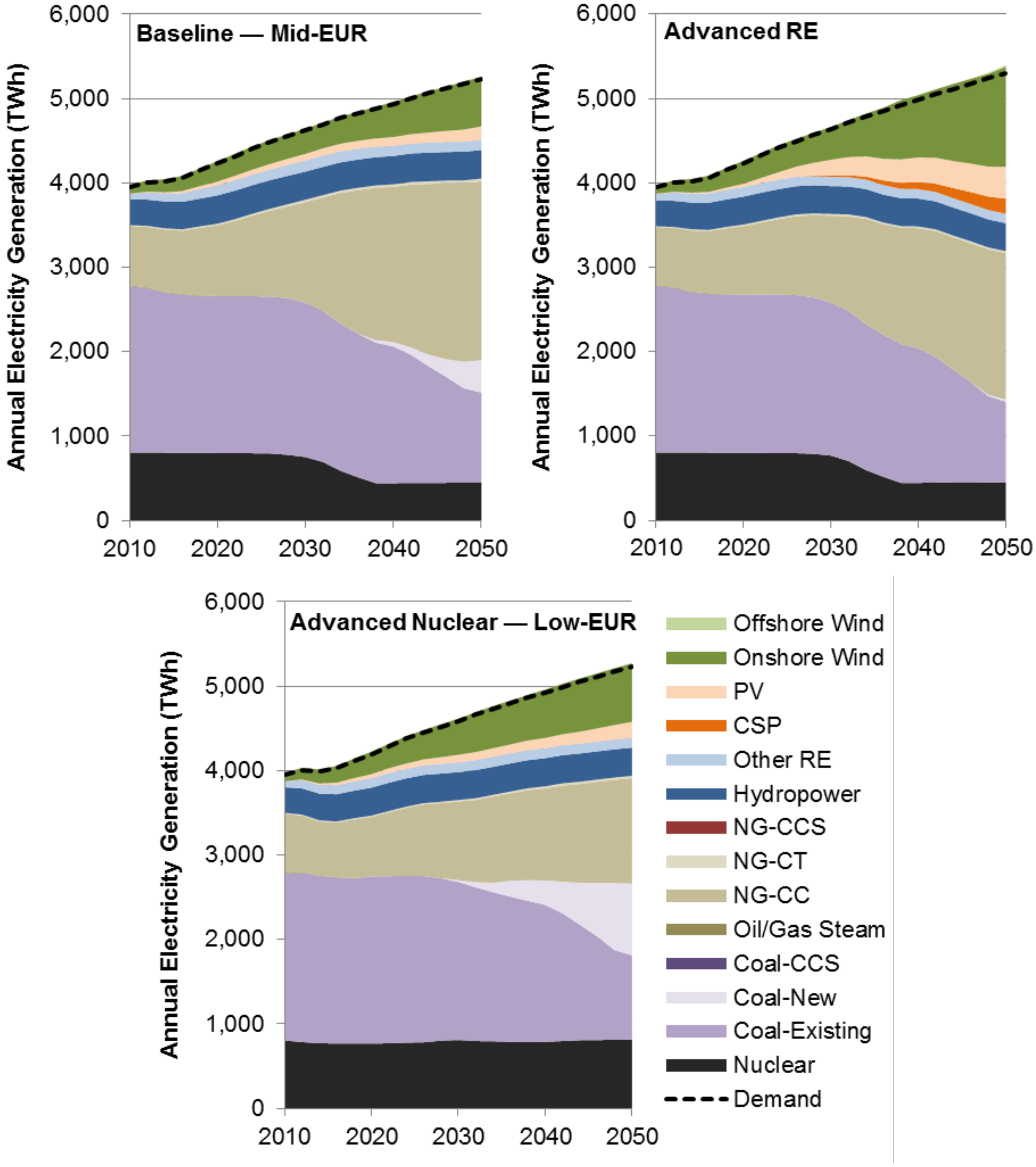


Figure 34. Generation in the Advanced Technology scenario, 2010–2050

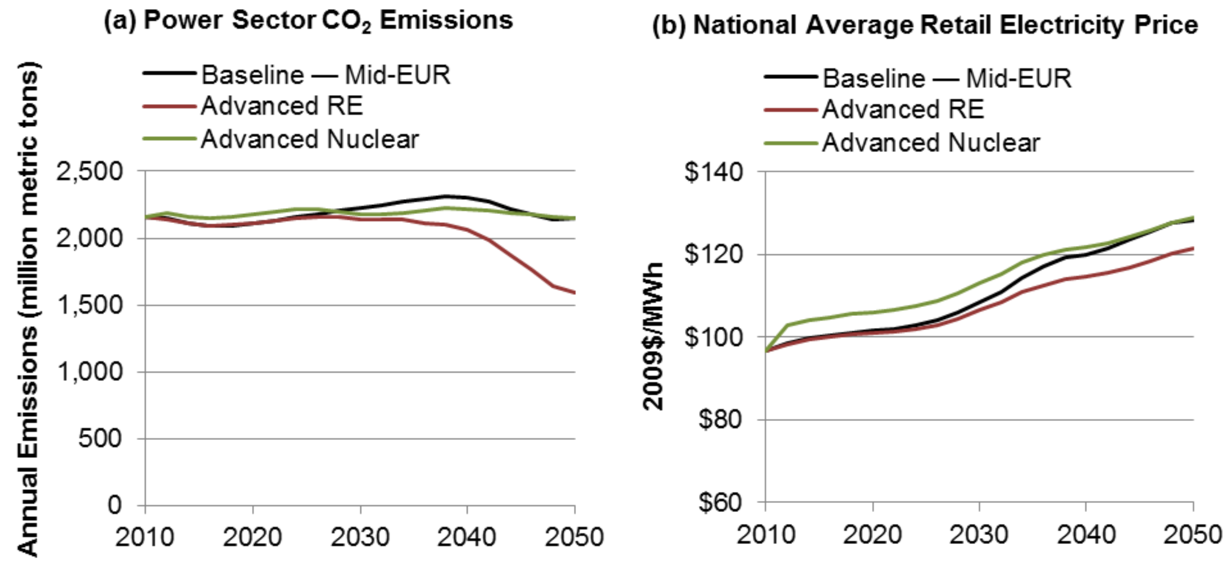


Figure 35. Selected metrics for the Advanced Technology scenario, 2010–2050

4.7 Natural Gas Supply and Demand Variations Scenario

Two separate cases are considered here:

- *Natural Gas Supply Cost Variations:* Variations in natural gas supply costs that could result either from additional state or federal regulations, or from more costly field practices that suppliers follow to better protect the environment. The impact of these incremental natural gas costs on the power sector over the longer-term are simulated using ReEDS. This analysis covers a broad range of potential incremental costs associated with producing natural gas in a way that commands stronger public support yet is still feasible for producers and consumers. Chapters 2 and 3 of this study discuss practices that could result in this more secure outcome on the supply side, but does not arrive at actual estimates of incremental cost impacts in $/MMBtu terms. The values used here could still be helpful to those who know what their incremental costs are, or to a broader audience in the future when cost estimates are available.
- *Natural Gas Demand Variations:* Variations in demand for natural gas outside the power sector that could result from a "dash-to-gas" across the larger economy. This dash-to-gas could occur in the export of LNG, greater use of natural gas in vehicles (either as compressed natural gas throughout the fleet, or as LNG in heavy-duty vehicles). Under a dash-to-gas case, natural gas prices rise due to the greater demand and make it more expensive for power generators to use natural gas generation.

Table 15 summarizes key assumptions used in the Supply and Demand Variations scenario.

Table 15. Description of Natural Gas Supply and Demand Variations Scenario

Case Name	Focus	Assumption for Estimated Ultimate Recovery
Natural Gas Supply Cost Variations	Evaluate impact to power sector as incremental natural gas production costs increase from $0.50/MMBtu to $2/MMBtu	Mid-level
Natural Gas Demand Variations (Dash-to-Gas)	Evaluate impact to power sector as natural gas demand in other sectors increases by 12 bcf/d by 2026	High-level

4.7.1 Natural Gas Supply Cost Variations

Figure 36 illustrates adjustments to the natural gas supply curves that could result when additional measures are taken to protect the environment when producing natural gas. These measures could be the result of new regulations or different practices in the field. Examples of these added costs might include the following:

- Activities such as recycling or treating a greater quantity of water supply used in hydraulic fracturing
- Minimizing the amount of methane that is released to the atmosphere before, during, and after fracturing a well
- Casing wells in a more robust and consistent way
- Practicing more robust techniques of cement bond logging
- Substituting more environmentally benign options for traditional hydraulic fracturing additives
- Engaging local stakeholders in dialogues in advance of drilling to ensure their concerns are heard and addressed
- Enforcing larger setbacks from potentially sensitive communities
- Disposing of or treating flowback water in improved ways.

Few publicly available studies estimate what these specific costs might be and how they vary by region. The International Energy Agency (IEA) recently published Golden Rules for a Golden Age of Natural Gas (IEA 2012), a very general statement of 22 steps that should be considered when producing natural gas. The IEA report stated that, "We estimate that applying the Golden Rules could increase the overall financial cost of development a typical shale-gas well by an estimated 7%."[sic] (IEA 2012). Therefore, if it normally costs $3.00/MMBtu to develop shale gas, the Golden Rules cost would be $0.21/MMBtu higher at a typical play. This is nominally consistent with, although lower than, recent estimates of the costs of complying with pending federal rules—including the new EPA air regulations for oil and gas producers, which might cost between $0.32 and $0.78/MMBtu, according to one analyst (Book 2012). Informal consultations associated with this study suggest that maximizing water recycling might result in $0.25/MMBtu in added costs. The additional costs that could result from enhanced environmental and safety practices in the field, noted in Chapters 2 and 3, were unable to be quantified. However, it is clear that these costs will vary by region and that many additional safeguards could be practiced at less than an incremental cost of $1/MMBtu. A 2009 study funded by the American Petroleum

Institute anticipated much higher costs if new federal regulations were imposed on natural gas producers (IHS 2009).

To assess the potential impacts of these incremental supply costs, this study considers a range of additional costs—starting from $0.50/MMBtu and going up to $2/MMBtu in increments of $0.50/MMBtu—and evaluates the impacts on the long-range evolution of the power sector when these costs are applied. Figure 36 shows the reduction in natural gas use in the power sector as incremental costs are increasingly applied. At the upper limit, natural gas consumption for power generation declines from roughly 15 quads[146] in the Baseline – Mid-EUR case to 10 quads (incremental $2/MMBtu added) by 2050. With a $0.50/MMBtu added cost of gas production, the long-term impacts are far more modest—resulting in a reduction of gas use for power generation in 2050 of less than 2 quads. Coal—and wind, to a lesser extent—replaces the generation lost by the more expensive gas. Other impacts associated with these assumed incremental costs appear relatively modest.

[146] To roughly convert from quads to bcf/d, multiply by 2.6. Thus, 15 quads per year equal about 38.5 bcf/d.

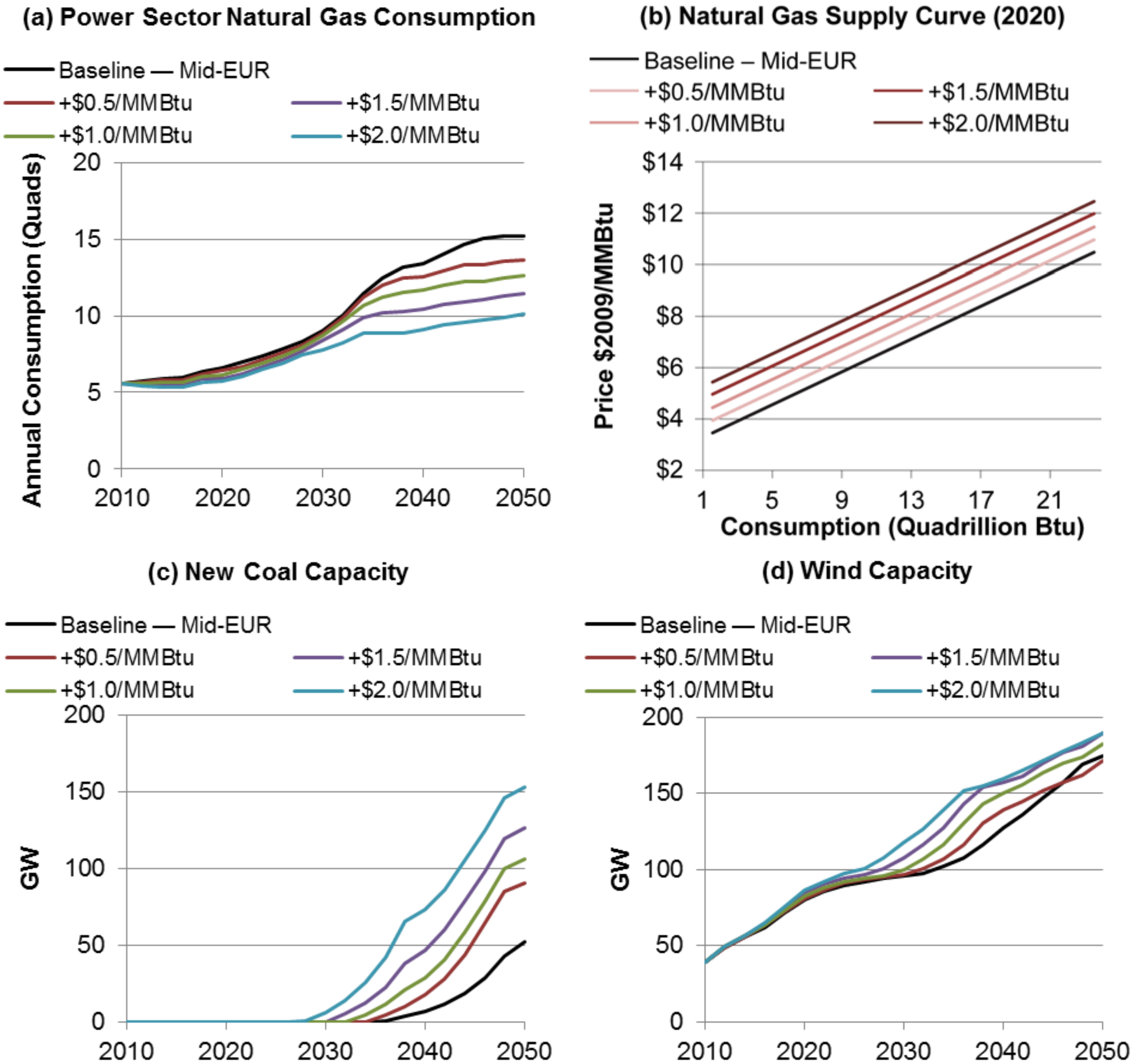


Figure 36. Selected metrics for the Natural Gas Supply Cost Variation case, 2010–2050

4.7.2 Natural Gas Demand Variations (Dash-to-Gas)

The Natural Gas Demand Variations case considers the impact to potential expansion of natural gas generation if a significant shift to natural gas occurs in other sectors of the economy. Specifically, it looks at the combined potential of new LNG exports, natural gas vehicle deployment (both compressed natural gas and LNG in heavy-duty trucking), and use in industrial and chemical applications and any other sector that in aggregate reaches 12 bcf/d by 2026.

A growing number of studies analyze the impact of LNG exports on domestic natural gas prices (EIA 2012b; Pickering 2010; Deloitte 2011; Ebinger et al. 2012). Estimates vary considerably depending on methodology used, location, and assumptions about overall gas availability. The case examined here uses the methodology in the EIA LNG exports scenario as a basis for the full economy "dash-to-gas."[147] Thus, it takes the "high and slow" EIA-derived price impact of exporting 12 bcf/d of LNG by 2026 and uses it to represent the impact of a combined 12 bcf/d in the total economy, distributed among LNG exports, vehicle use, industrial use, and any other applications (see Figure 37 and Table 16).

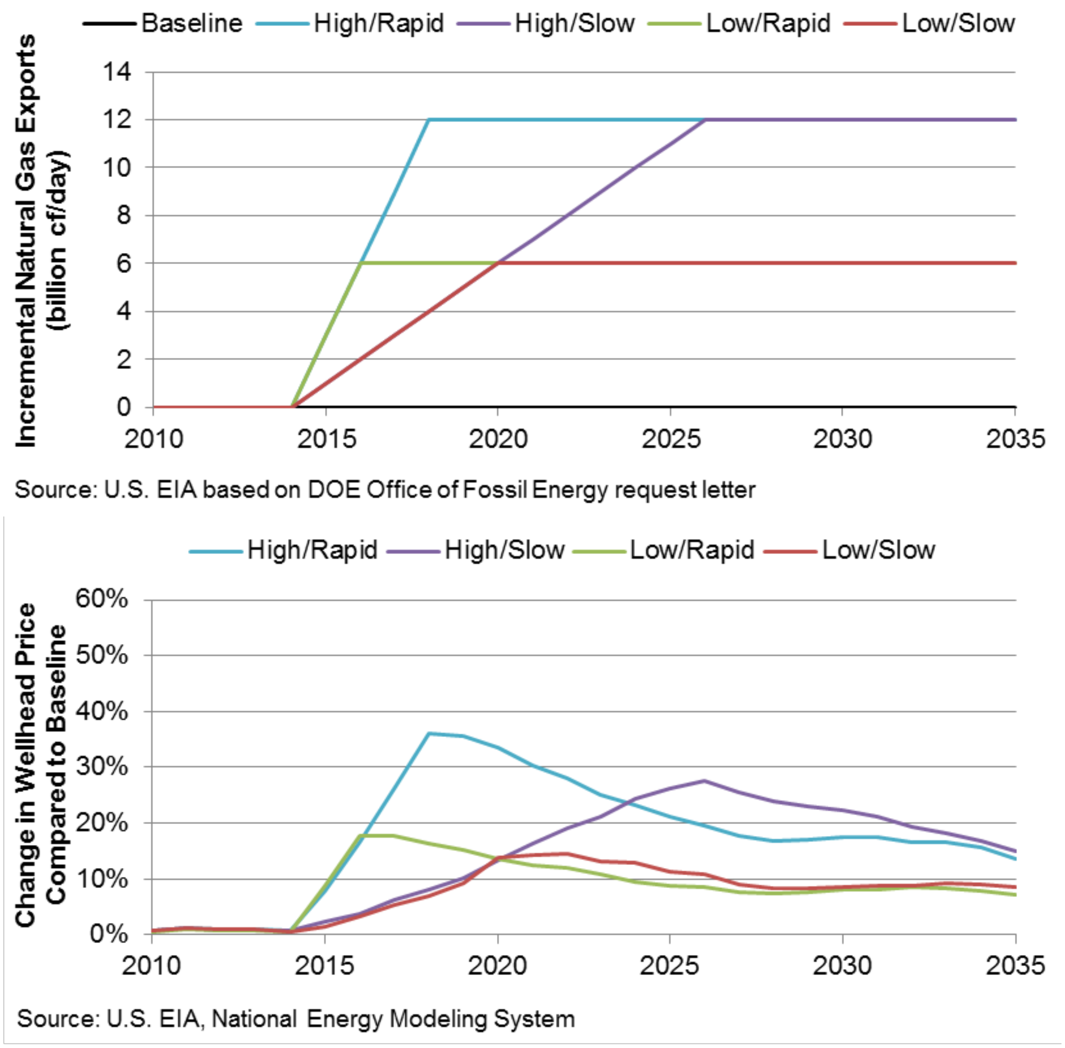


Figure 37. EIA LNG export scenarios and their projected impacts on domestic natural gas prices, 2010–2035

[147] The upper limits (i.e., high/rapid scenario) of the EIA study have been criticized by some (Ebinger et al. 2012) as too extreme and not representative of how LNG exports might really occur. Although the study in this report uses the second-most extreme (high/slow) LNG export scenario considered by the EIA, the scenario is constructed to capture a wider range of potential natural gas end-uses than just LNG exports.

Table 16. Non-Power Sector Natural Gas Demand Assumptions in the Natural Gas Demand Variations Case

	2010	2020	2030	2040	2050
	(billions of cubic feet per day)				
LNG Exports	0	5.0	7.3	5.0	0
Vehicles[148]	0	1.5	2.7	3.0	0
Industry/Other	0	1.5	2.0	1.5	0
Subtotal	0	8.0	12.0	9.5	0

In the Natural Gas Demand Variations (dash-to-gas) case, gas prices rise by a maximum of 29% above the Reference scenario value in 2026 before re-equilibrating. The power sector mix is similar to the Baseline – Low-EUR case (compare Figure 38 with Figure 26), although still slightly more reliant on natural gas generation. A dash-to-gas future, then, would restrict gas generation to less than doubling by 2050 compared to the 2010 level. The larger macroeconomic impacts associated with this future were not evaluated; however, overall gas demand declines by about 3 quads by 2050 (Figure 39) compared to the baseline. The price of natural gas for power generators rises by a maximum of $2/MMBtu above the baseline value in the early 2020s before returning to the baseline level in 2050, when the other sectors are assumed to terminate their extra reliance on natural gas (see Figure 39).

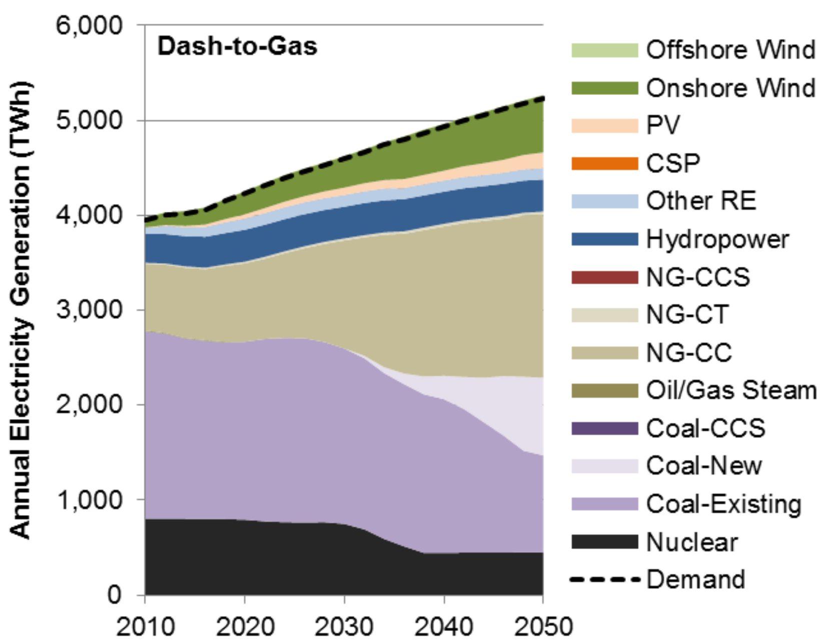


Figure 38. Power generation mix in the Dash-to-Gas case

[148] These estimates for compressed natural gas use in vehicles are proposed by Wellkamp and Weiss (2010).

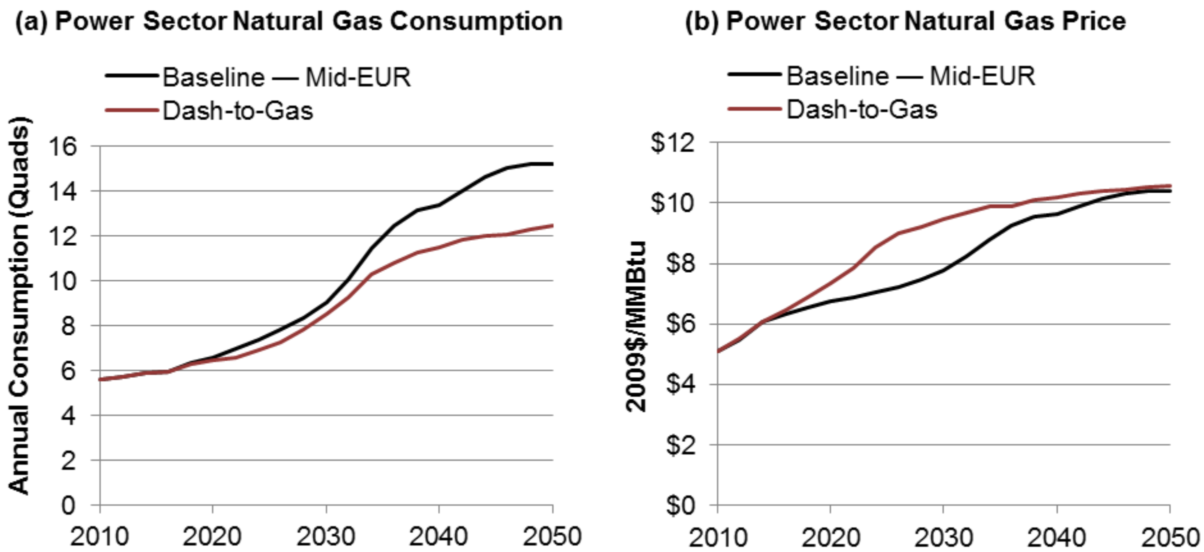


Figure 39. Selected metrics for the Dash-to-Gas case, 2010–2050

4.7.3 Implications of the Natural Gas Supply and Demand Variations Findings

Many additional measures could be taken by producers to address the real and perceived risks associated with unconventional natural gas production at a modest impact to the evolution of the power sector. If total costs from a long list of potential practices reached $1.00/MMBtu, natural gas usage in the 2050 power sector might be expected to decline from 2.5 times the 2010 level in the Baseline to 2 times in the Supply Variation case. Costs associated with ensuring stronger public support of unconventional gas and oil production would vary by region and producer. Technologies associated with unconventional natural gas production are under rapid development, so the cost impacts will be changing dynamically. Follow-on research should attempt to gather additional data from producers to better estimate what the real cost would be of addressing issues of social license to operate on a basin-by-basin level. The question for industry might then be: Are these added costs worth absorbing—and an acceptable price to pay—to ensure both greater public and utility-sector confidence in the production practice over the longer term?

Understanding the price impacts of a Dash-to-Gas case is still poorly characterized due to the newness of the recent change in natural gas supply outlook. Based on currently available estimates, a fairly strong dash-to-gas in other sectors of the economy would have a visible, although still marginal, impact on the evolution of the electric power sector—with natural gas use declining somewhat due to the higher prices and other forms of generation increasing to take its place. As additional experience and estimates of this elasticity become available, follow-on research should re-examine the impacts.

4.8 Conclusions for Power Sector Modeling

The role of natural gas in the U.S. power sector is sensitive to assumptions about EUR. More research is needed to better understand how much gas will ultimately be recovered from unconventional plays.

Coal retirements and fuel switching are already occurring ahead of the rollout of EPA rules. The modeling results indicate that any new plants needed to replace retiring coal would mostly be fired by natural gas and that on an aggregate level, reliability standards are maintained without an unusual level of new construction. This analysis did not attempt to evaluate location-specific reliability impacts associated with coal-plant retirements; more granular dispatch models would be needed to investigate those questions with more certainty.

The CES modeling results indicate that substantial reductions in CO_2 emissions are achievable at modest cost, although transmission barriers could stand in the way. When CCS is not available under a CES, generation options decline, the need for new transmission expands significantly, and the power mix becomes less diverse. Therefore, CCS is an important option for a low-carbon power sector, but may not be essential.

Continued focus on technology research, development, and deployment is needed to bring down costs and ensure a diverse power mix in the future. Even modest reductions in renewable energy capital costs and improvements in performance may have a meaningful impact on their continued deployment in the future. Continued advancements in technologies used to find and produce unconventional gas could also have a strong impact on improving the social license to operate at an acceptable price, and thus, should be pursued at all levels.

Finally, increased costs associated with potential changes in field practices of natural gas producers were evaluated over a fairly broad range. If these costs turn out to be less than an incremental $1/MMBtu, then the long-term impact on natural gas in the power sector is not significantly different from the baseline conclusions: gas demand for power generation declines by about 17% while CO_2 emissions increase marginally. An important outcome of this study—and a potential question for follow-on research and discussion—would be whether these additional costs associated with protecting the environment, improving safety, and commanding public confidence are worthwhile to society and gas producers.

Natural gas appears plentiful and at historically low price levels for the foreseeable future, but going forward, decision makers may want to pay special attention to generation diversity. An undesirable outcome would result if a major shift to natural gas generation occurred before a substantial rise in natural gas prices—due, for example, to mischaracterizations of EUR, a failure to earn the social license to operate, or some other reason that may currently be considered "unlikely." Continuing research, development, and deployment over a wide variety of generation and gas production options can help prevent such an outcome. It would also provide greater flexibility in addressing the threat of climate change.

5 Conclusions and Follow-On Research Priorities

5.1 Conclusions

Major, high-level findings derived from the research conducted in this study include:

- Life cycle greenhouse gas emissions associated with electricity generated from the Barnett Shale play gas in 2009 were found to be very similar to conventional natural gas and less than half of those associated with coal-fired power generation.
- Low-priced natural gas has led to more than 300 terawatt-hours of fuel switching from coal to gas in the U.S. power sector between 2008 and 2012. This switching, in combination with rapid growth in certain renewable energy generation sources, has led to a reduction in power-sector carbon dioxide emissions of about 300 million tons—about 13% of the sector's total. This fuel switching may stop or reverse itself if natural gas prices rise relative to coal. Natural gas can play an important role in greenhouse gas mitigation over the short- to mid-term, but if policymakers pursue an 80% mitigation target by 2050, carbon capture and sequestration may need to be commercially viable by 2030 for natural gas power generation to continue growing.
- The legal and regulatory frameworks governing shale gas development are changing in response to public concerns, particularly in regions that have less experience with oil and gas development. All of the states examined in this study have updated their regulatory frameworks to address the opportunities and challenges associated with greater unconventional natural gas production. Better coordination and information sharing among regulators may help ensure efficient and safe production, while greater availability of transparent and objective data may help address some of the public's concerns.
- States and natural gas producers are developing additional, often voluntary, field practices to ensure that shale gas can be produced with high standards of environmental protection—although these standards are not always uniformly followed. Continued advances in technologies and practices could help address public concern over unconventional gas production. Some data, such as the amount of water used per well in hydraulic fracturing, are readily available and can be analyzed on a regional basis. However, a lack of publicly available information on industry practices limits a full-scale assessment of water risks associated with shale gas operations. Further collaboration and interaction with industry partners could help improve data collection efforts.
- A suite of different future electric power scenarios was evaluated to test the implications of different policy and technology changes. These scenarios include power plant retirements, advances in generation technologies, federal policies to reduce greenhouse gases, and variations in natural gas supply and demand. The study found that natural gas use grows robustly in nearly all scenarios over the next two decades. Over the longer term, natural gas demand for electricity generation faces greater uncertainty, leading to larger ranges of change in gas demand—including the case where demand in 2050 is roughly the same as that in 2010 in the event a clean energy standard is pursued and carbon capture and sequestration is not commercially available (see Figure 32).

Readers should consult corresponding chapters to view more comprehensive findings and ensure that the appropriate context is conveyed with each finding.

5.2 Follow-on Research

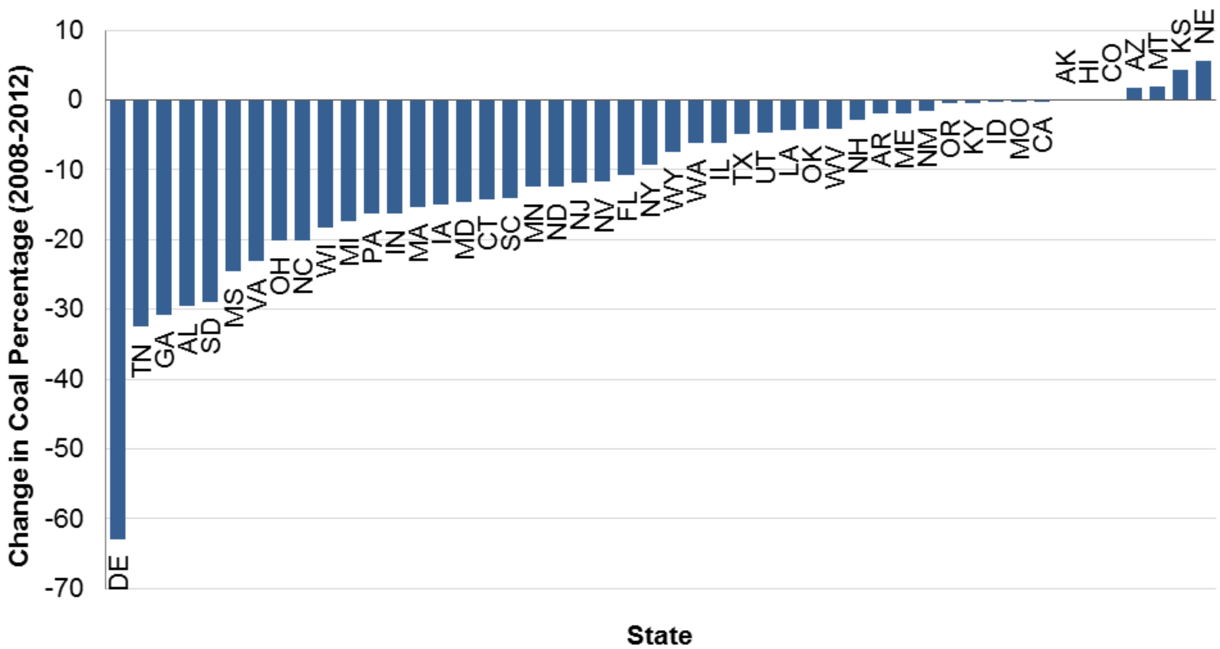
Because of time and budget constraints, the research team could not investigate some issues as fully as warranted. Each chapter identifies areas where additional research would likely lead to improved understanding on certain issues. Selected follow-on research taken from this larger list is presented below. Please refer to the main chapters for a more comprehensive discussion on these follow-on research topics.

- More field-measurement-based research on methane leakage and mitigation options at unconventional gas production facilities (outside of the Barnett Shale play) considering geographic and operational variability at well, play, and national scales.
- More industry- and basin-specific research to estimate the incremental costs associated with various regulatory scenarios, including more robust environmental standards in unconventional gas production. Additional social research to understand how improved standards might impact public perception of gas production and the social license to operate. Additional economic research to understand how higher costs would impact producers, and the degree to which they might be able to pass costs on directly to consumers.
- More comprehensive evaluation of risks in shale gas production and how they can be best addressed using new technologies and field practices. Increased quantitative understanding of the magnitude and probability of risks to water resources that result from current industry practices and proposed best management practices. More comprehensive evaluation of the regional diversity of risks, costs, and effective industry practices inherent in shale gas development.
- Greater understanding of the impact of additional natural gas demand, especially liquefied natural gas exports, on domestic and international prices. In general, greater certainty and understanding of natural gas price volatility and estimated ultimate recovery in the relatively new abundant natural gas environment would also be beneficial.
- Finally, this study did not use a modeling tool that simulated operation and expansion of natural gas pipelines. Follow-on work that included such capabilities might identify additional opportunities and barriers to growth in electric power natural gas use.

Appendix A: Shifting Coal Generation in U.S. States

This appendix summarizes recent data on changes in coal-fired electricity generation published by the Energy Information Administration (EIA) of the U.S. Department of Energy. Many of these changes are due to some combination of low-priced natural gas, aging coal generators, and impending regulations from EPA. However, some changes—especially in small states—could be unrelated. Using data at the state level—rather than the larger boundaries of regional transmission organizations or independent system operators—is somewhat artificial when showing changes in electricity generation. Nevertheless, state-level data are convenient, and important trends can be seen in the grouping of some states.

Figure 41 presents a snapshot of the change in coal-fired generation percentage between 2008 and the first 2 months of 2012 for most states. The charts that follow provide additional information on how changes in generation mix have occurred in the first 15 states shown in Figure 41.



Data: U.S. Energy Information Administration, Electric Power Monthly, data through February 2012.
Note: DC, RI, and VT are not included.

Figure 41. Changes in coal percentage of total net generation at the state level, 2008–2012

Figure 42 through Figure 56 show how generation mix has changed between 2005 and early 2012 for the 15 states with the largest drop in coal percentage as a percent of total net generation. The data for all of these figures come from the U.S. Energy Information Administration, "Electric Power Monthly." The data are through February 2012, and the 2012 data include only January and February net generation. Some seasonal effect is reflected in the 2012 year-to-date data points.

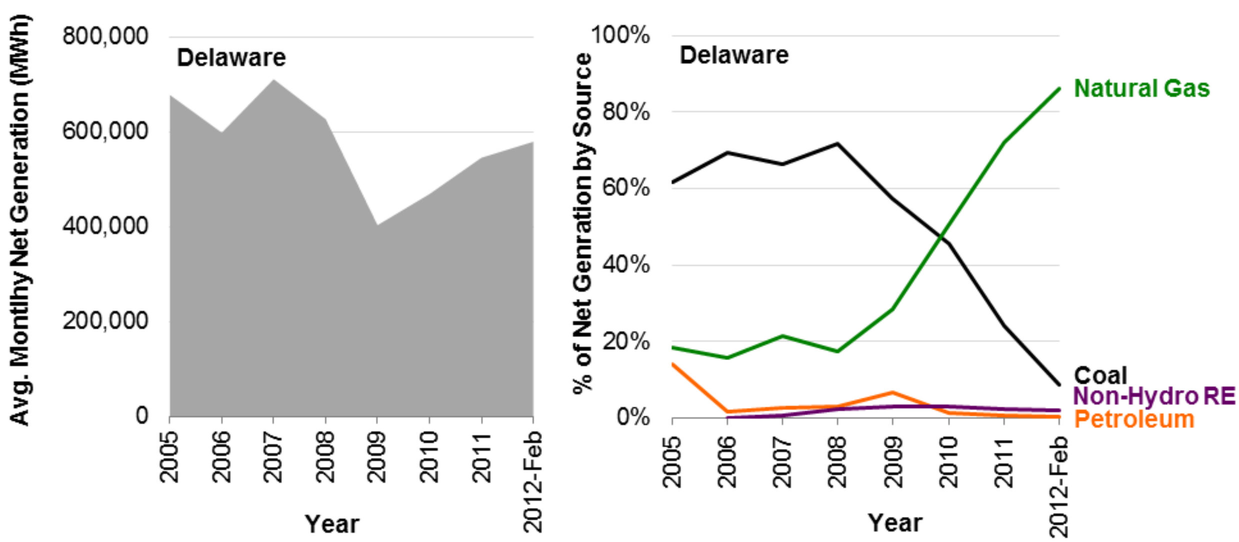


Figure 42. Changes in generation mix in Delaware; 2005–early 2012

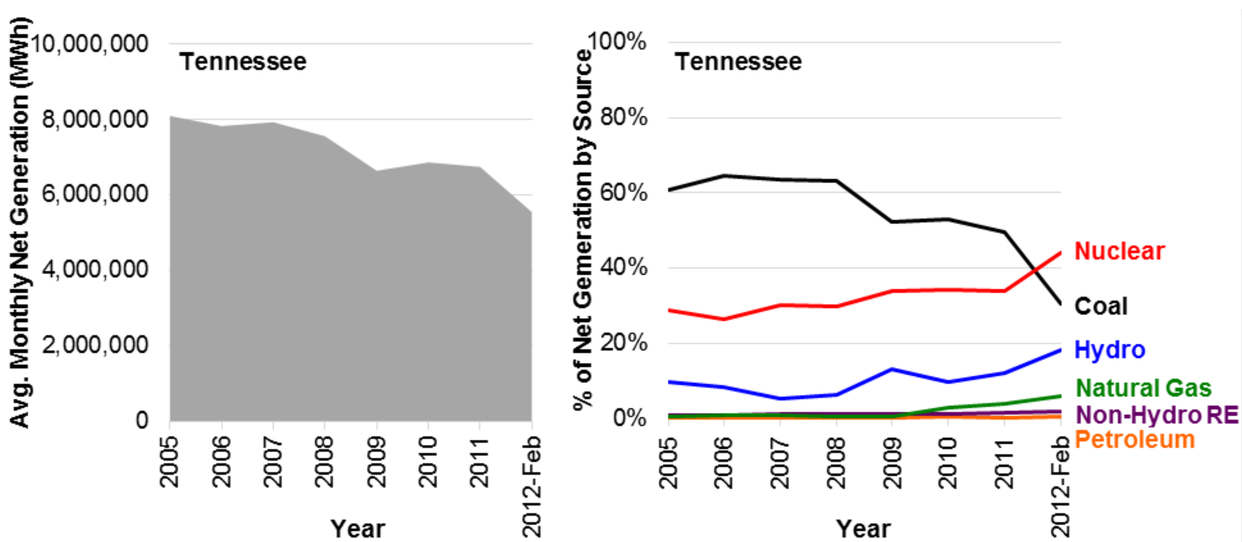


Figure 43. Changes in generation mix in Tennessee; 2005–early 2012

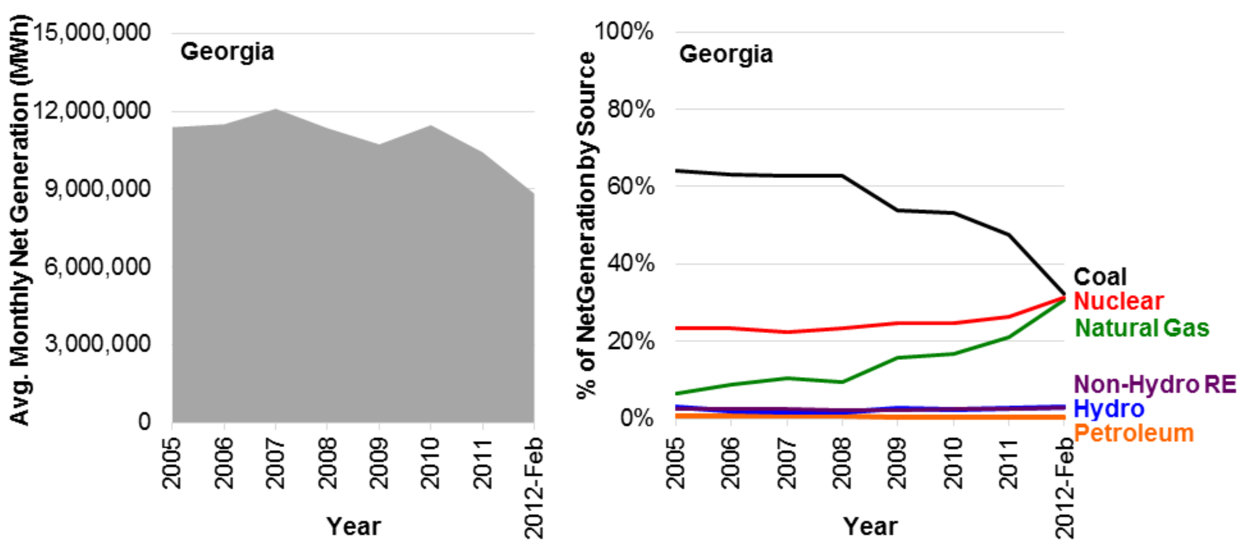


Figure 44. Changes in generation mix in Georgia; 2005–early 2012

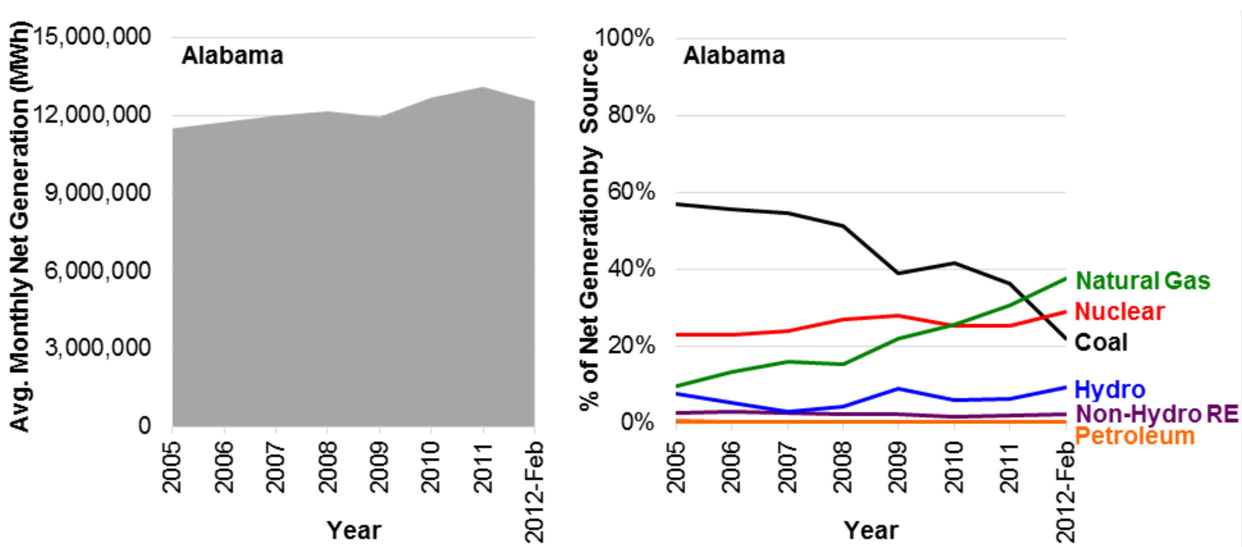


Figure 45. Changes in generation mix in Alabama; 2005–early 2012

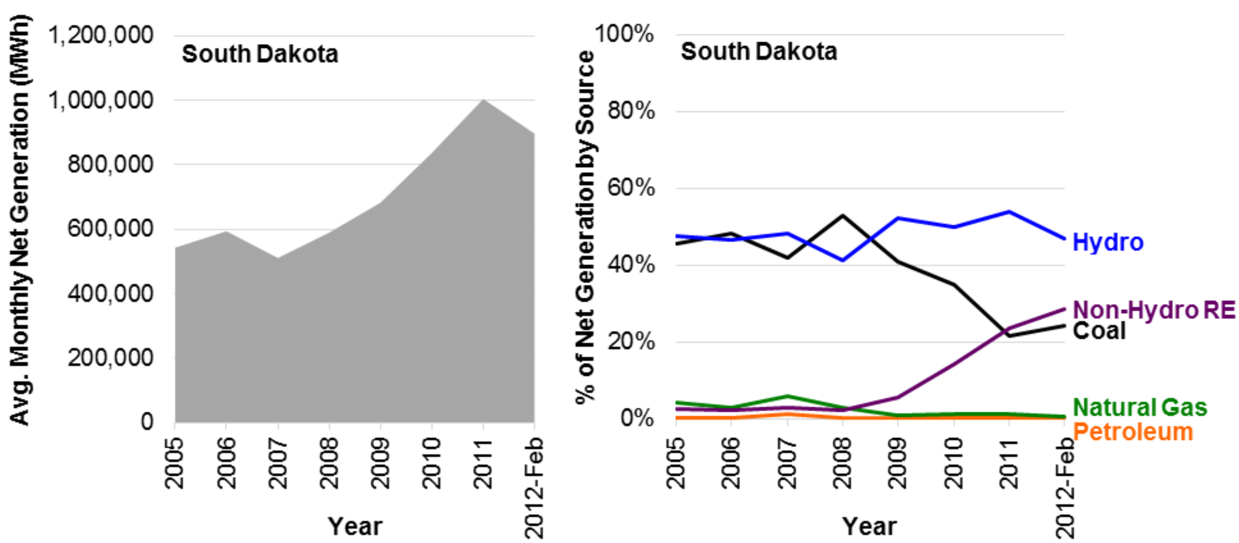


Figure 46. Changes in generation mix in South Dakota; 2005–early 2012

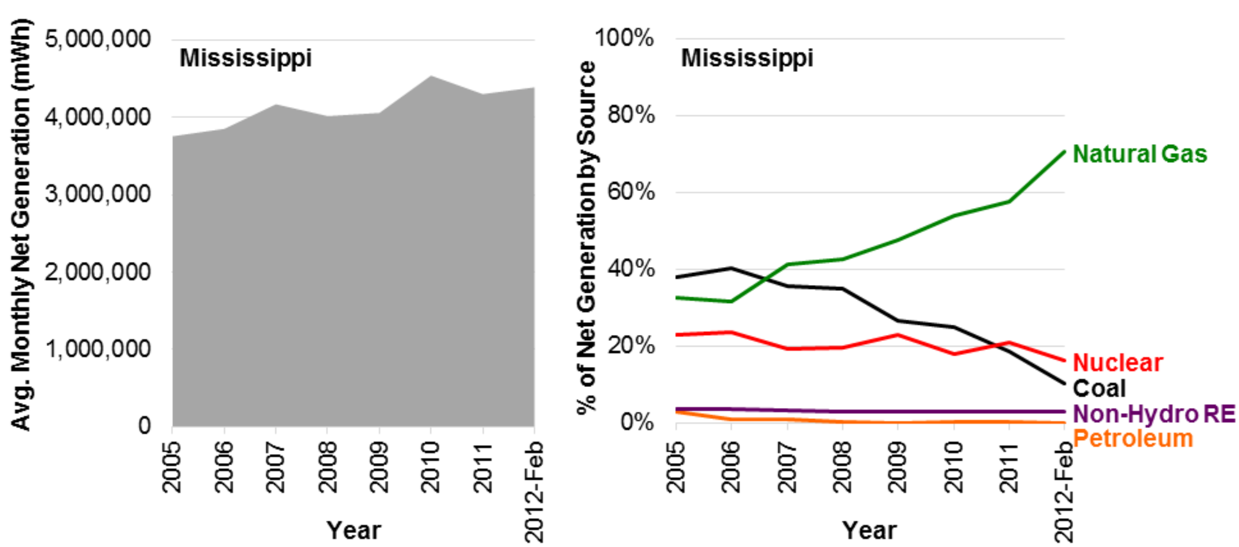


Figure 47. Changes in generation mix in Mississippi; 2005–early 2012

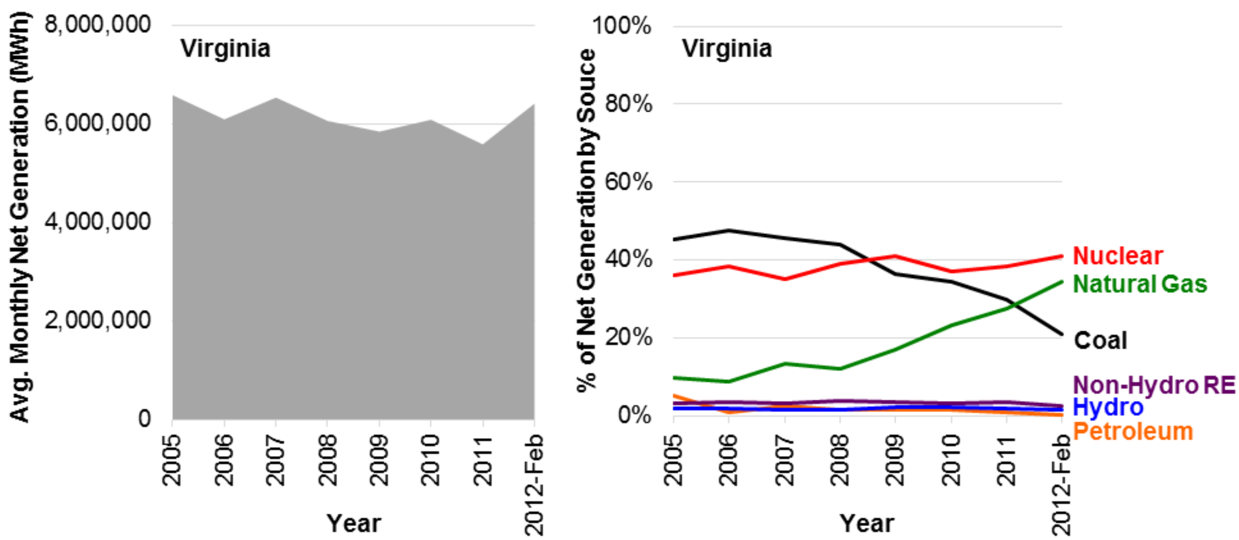


Figure 48. Changes in generation mix in Virginia; 2005–early 2012

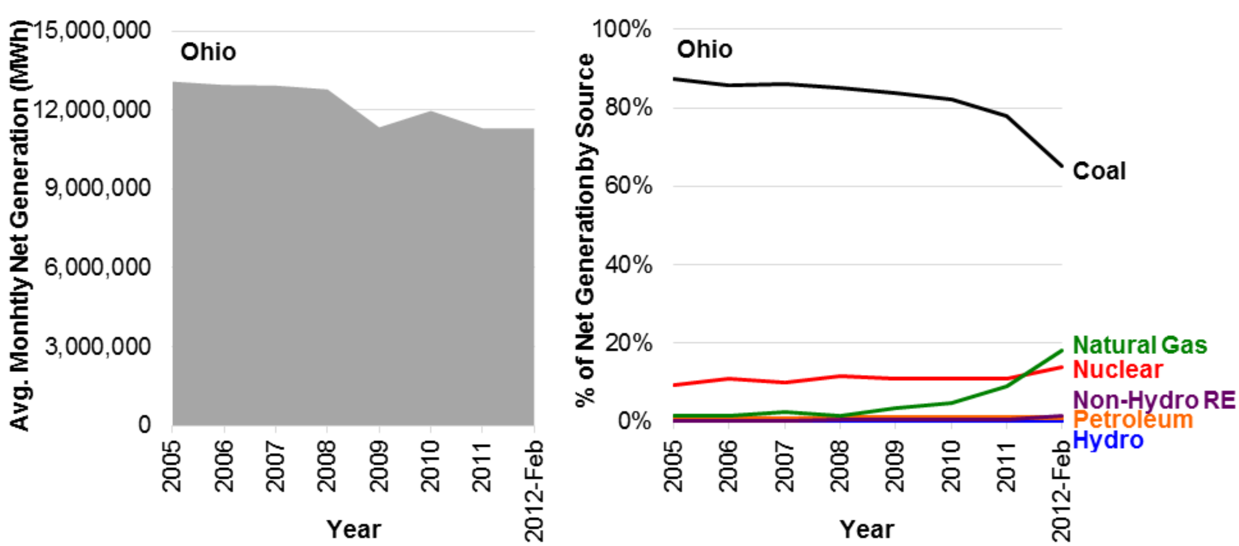


Figure 49. Changes in generation mix in Ohio; 2005–early 2012

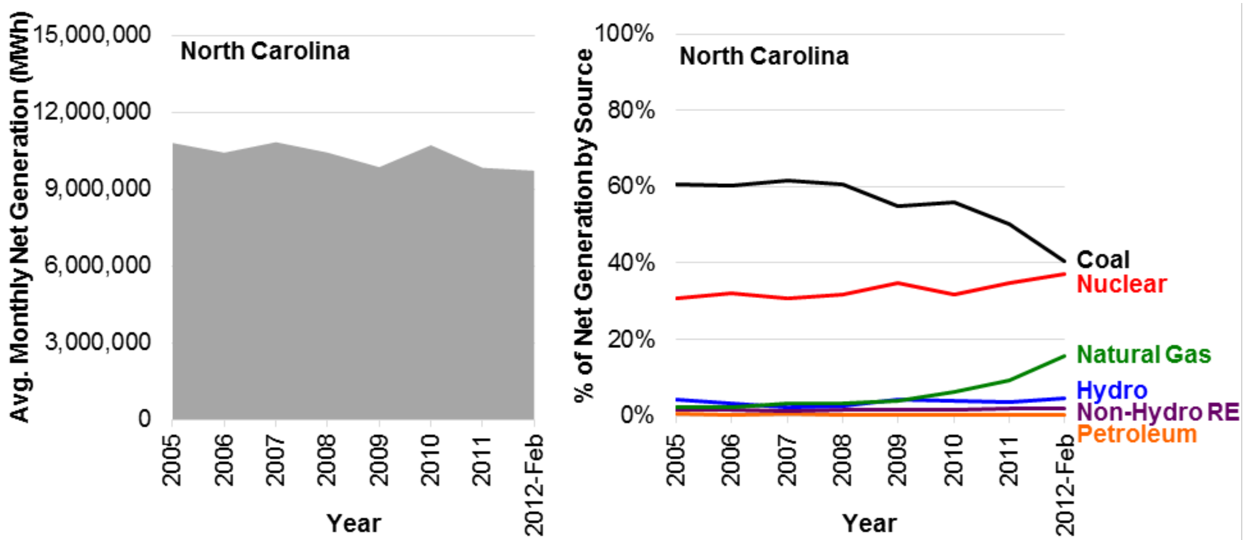


Figure 50. Changes in generation mix in North Carolina; 2005–early 2012

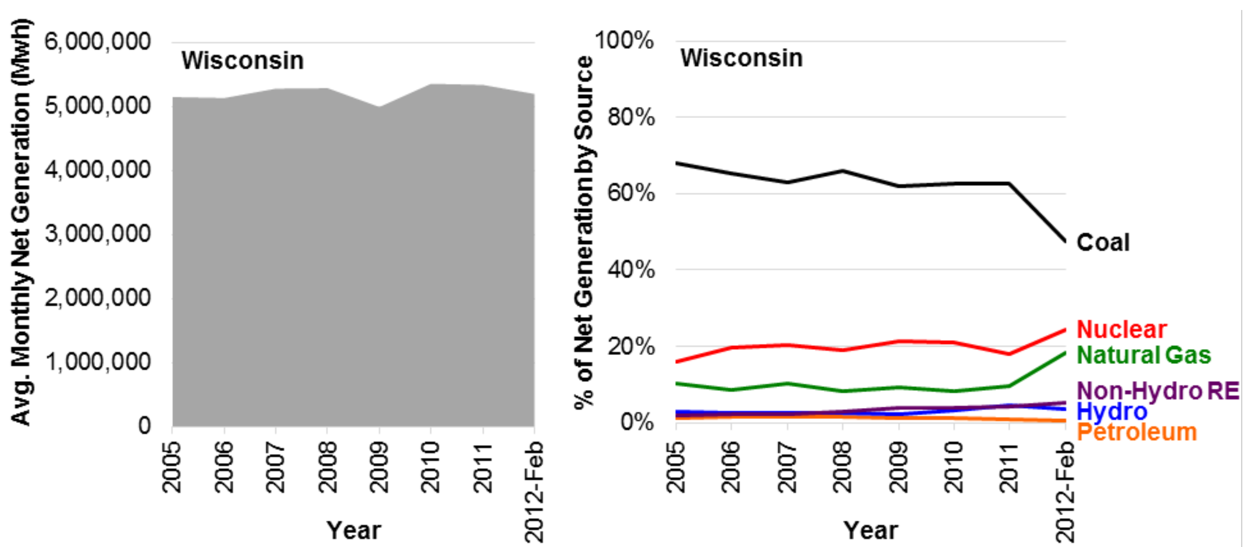


Figure 51. Changes in generation mix in Wisconsin; 2005–early 2012

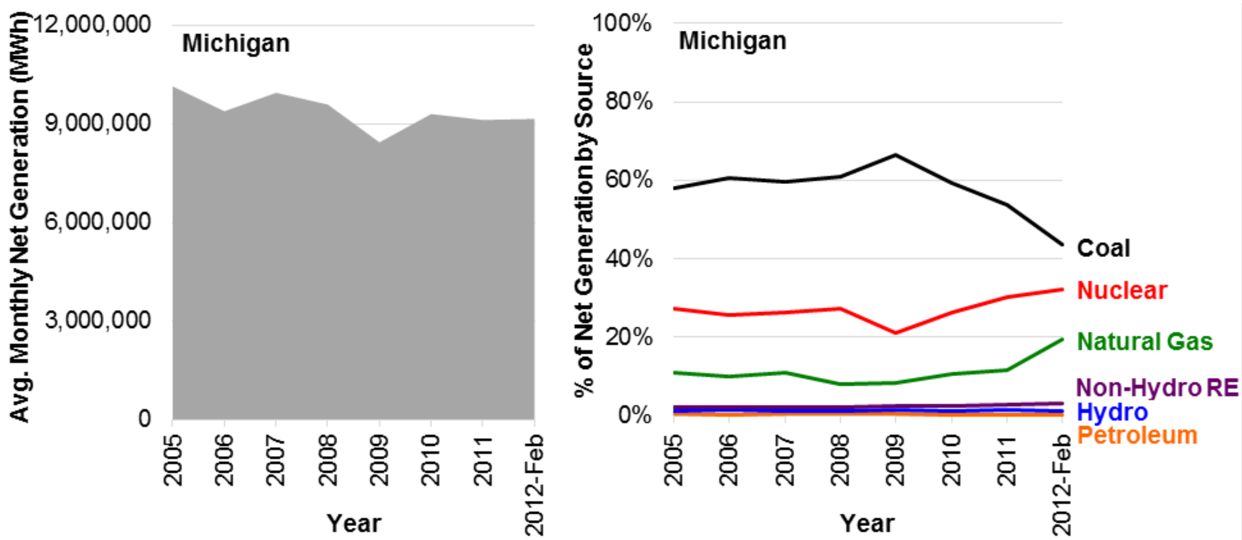


Figure 52. Changes in generation mix in Michigan; 2005–early 2012

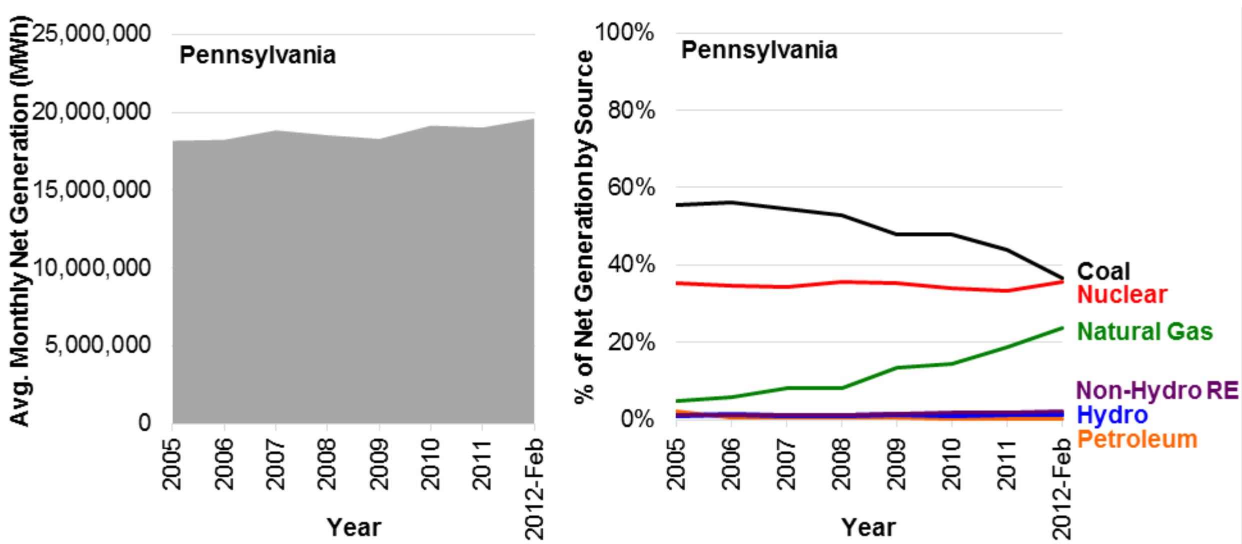


Figure 53. Changes in generation mix in Pennsylvania; 2005–early 2012

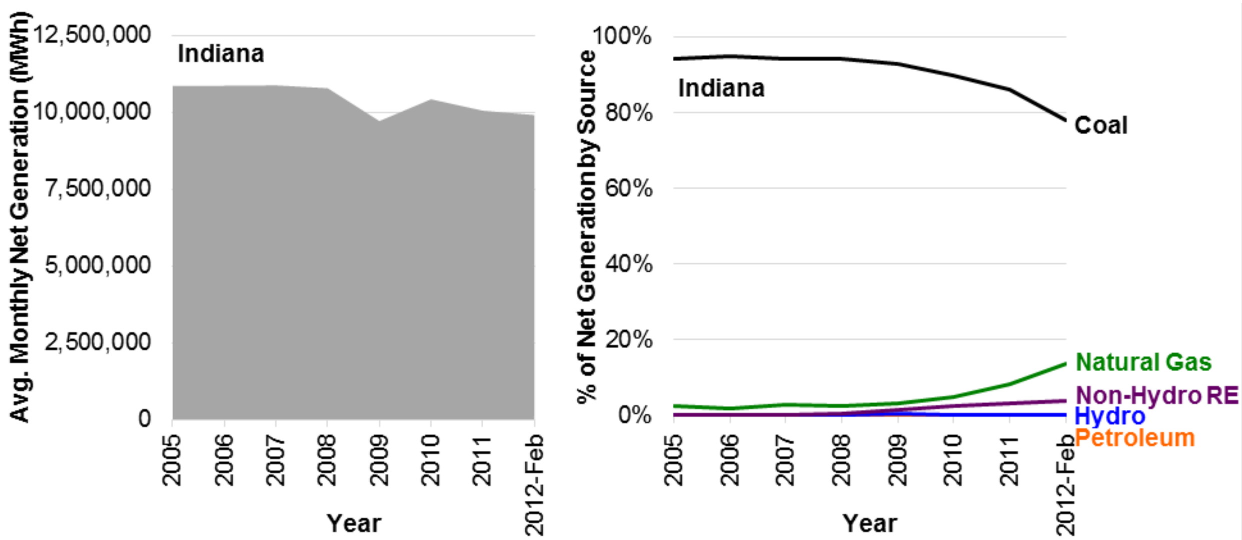


Figure 54. Changes in generation mix in Indiana; 2005–early 2012

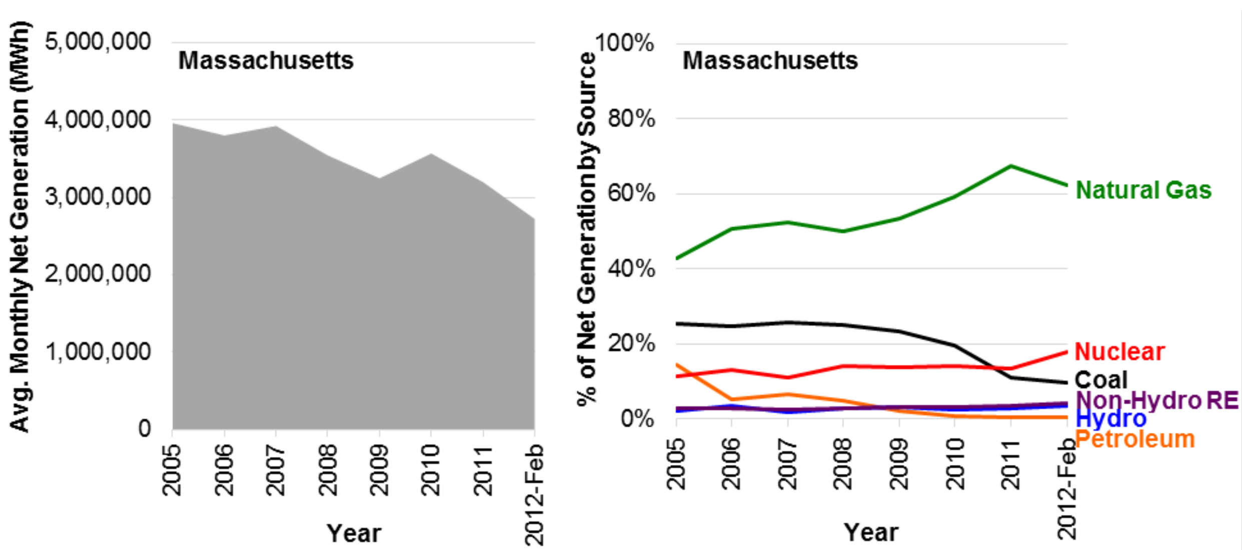


Figure 55. Changes in generation mix in Massachusetts; 2005–early 2012

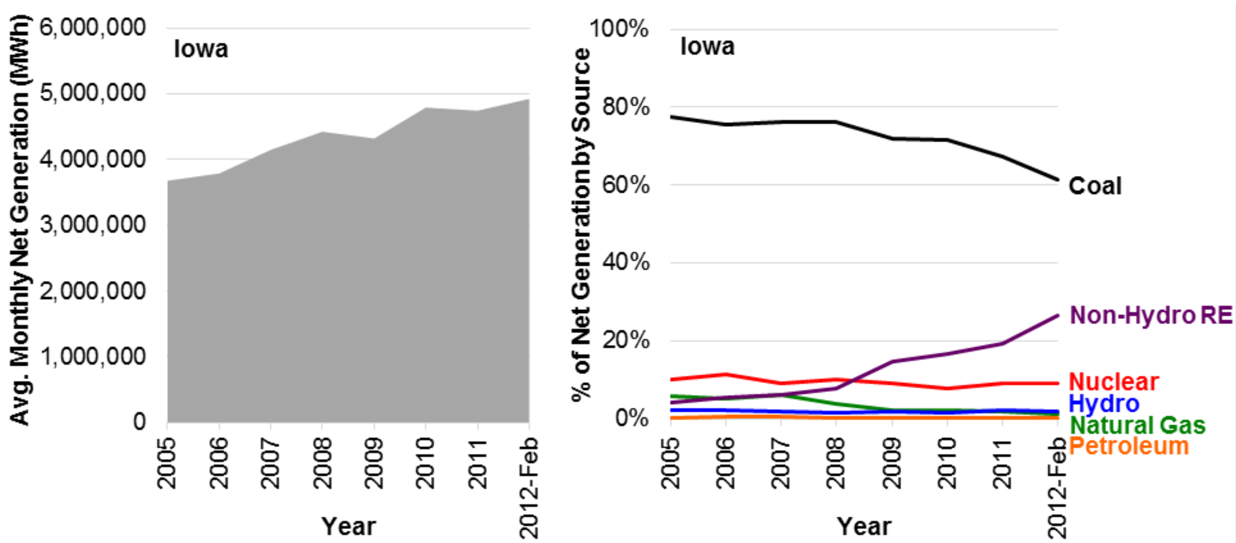


Figure 56. Changes in generation mix in Iowa; 2005–early 2012

Appendix B: Details and Considerations of Methods

This appendix offers details of data, methods, and results for Chapter 1. First, we define several terms relevant to estimating GHG emission factors from the TCEQ inventories.

The *basin* refers to 22 counties under which the Barnett Shale is being developed. Therefore, production in the basin includes production from the Barnett Shale as well as a small amount of additional production from other geological formations contained within the 22 counties.

As defined by the TCEQ (2010: p.23), “any source capable of generating emissions (for example, an engine or a sandblasting area) is called a facility. Thus, facility and emissions source, or ‘source’ for short, are synonymous.” To avoid confusion, we use the term *source* to refer to any individual such facility.

Sources can be characterized into common types called *profiles*. Common examples of profiles include engines, turbines, fugitives, and tanks. Profiles are designated such that the emissions from sources with the same profile can all be estimated with a common method.

The term *site* refers to a physical location for which data are reported to the inventories, where each site consists of multiple different emissions sources. Each site is associated with a unique TCEQ account number and site name. Common examples of types of sites include wells, compressor stations, and gas processing plants. In the Special Inventory, sites are referred to as *leases*.

Production gas refers to the raw, unprocessed gas captured through development activities, and *pipeline gas* refers to the saleable final natural gas product. *Emissions* refer to tons of the specified pollutant(s) emitted per year, whereas *emission factors* refer to the amount of emissions associated with a unit of gas production. This report follows the EPA and TCEQ convention of referring to the set of non-methane, non-ethane hydrocarbons as *VOCs*.

TCEQ Inventory Data

The TCEQ collects an annual, statewide emissions inventory for sources classified as point sources per 30 Texas Administrative Code §101.10. For this study, data were obtained for any sources within this inventory with Standard Industrial Classification (SIC) codes pertaining to the production and processing of natural gas. From the point-source inventory data, GHG emissions are estimated from amine units, boilers, compressor engines, flares, fugitives, glycol dehydrators, heaters, produced-water loadings, produced-water tanks, natural gas turbines, and vents.

To complement the point-source inventory, the TCEQ performs an Area Source Inventory every three years. Data were obtained from the 2008 Area Source Inventory on VOC emissions from pneumatics and produced-water disposal activities, which were not available in the other inventories. These data are reported only at the county level. To combine emissions estimated from pneumatics with those estimated from other inventories, these profile’s emissions are adjusted by a factor equal to the change in gas production between 2008 and 2009, at the county level, as shown:

$$Adjustment = \frac{Q_{GWgas,2009}}{Q_{GWgas,2008}}$$

where:

$Adjustment$ = the county-level adjustment from 2008 to 2009 emissions estimates (unitless)

$Q_{GWgas,2008}$ = volume of gas-well gas produced in 2008 (Mcf)

$Q_{GWgas,b,2009}$ = volume of gas-well gas produced in 2009 (Mcf).

In 2009, the TCEQ performed a Special Inventory, for which it requested detailed equipment and production information for stationary emissions sources associated with Barnett Shale oil and gas production, transmission, processing, and related activities. The Special Inventory data cover only stationary emissions sources on site for more than 6 months that were not reported to the 2009 Point Source Inventory. These sources are used in this study to estimate GHG emissions from amine units, boilers, heaters, compressor engines, flares, fugitives, glycol dehydrators, produced-water loadings, produced-water tanks, and vents.

Some emissions sources are not reported to the Special Inventory that nonetheless contribute to the reported site-level total in that inventory. These sources are likely omitted because their emissions are below thresholds for reporting requirements for that inventory. However, although they may be individually negligible, their collective impact is significant—with the sum of the VOC emissions reported for all individual sources equaling only 93% of the sum of all site-level totals reported, across the entire inventory. To account for this underreporting, emissions estimated from Special Inventory data are scaled at the site-level by the inverse of the percentage of site VOCs accounted for by the individual sources reported at each site, as follows:

$$Correction_{site} = \frac{1}{\left[\frac{\sum_{k\in K_n} VOC_k}{VOC_n}\right]} = \frac{VOC_n}{\sum_{k\in K_n} VOC_k} \geq 1$$

where:

$Correction_{site}$ = the site-level correction for non-reported sources (unitless)

VOC_k = the mass of VOCs emitted from source k annually, where $k \in K_n$ is the set of reported sources at site n (tonne/year)

VOC_n = the reported total mass of VOCs emitted from site n annually (tonne/year).

In addition, to account for a stated 98% level of completion for the Special Inventory, all emissions estimated from the inventory's data by the inverse of that completion rate are also adjusted by the inverse of this estimate, as follows:

$$Correction_{inventory} = \frac{1}{98\%} = 1.0204$$

Stages of the Natural Gas Life Cycle

Emissions factors are compiled from the profiles associated with each life cycle stage.

Pre-Production Stage

The pre-production process stage consists of episodic activities related to the preparation of wells. Activities in this stage include the drilling and construction of wells, hydraulic fracturing of shale to stimulate production, and various well-completion activities, which specifically involve the following:

- *Drilling rigs* are used for drilling an oil or gas well. For the purpose of estimating emissions, rigs consist of a collection of diesel-powered engines, which are associated with combustion-generated GHG emissions.
- *Hydraulic fracturing* involves complex liquids, pumps, and trucks for transporting equipment and fluids, which are associated both with combustion-generated GHG emissions and with emissions from off-gassing and fugitives.
- *Well-construction activities* are associated with combustion-generated GHG emissions due to the use of heavy construction equipment.
- *Well-completion activities* involve the release of natural gas from a well before and during the installation of the equipment necessary for recovery of that gas.

Natural Gas Production Stage

The production process stage consists of ongoing activities related to the extraction of natural gas at a gas well. Emissions sources include the following:

- *Compressor engines* are used to maintain well pressure and for other processes at the wellhead. These engines, which typically burn the production gas being extracted, are associated with combustion-generated GHG emissions.
- *Fugitives* occur from the unintentional release of production gas through leaks from equipment and connections throughout the natural gas process chain; therefore, they are identified with a process stage by the type of site at which they are found.
- *Vents and blowdowns* refer to the intentional release of gas from equipment throughout the natural gas process chain; therefore, they are identified with a process stage by the type of site at which they are found.
- *Pneumatics devices* are used to open and close valves and other control systems during natural gas extraction. These sources are associated with gas release emissions, which depend on the composition of their identified contents.
- *Miscellaneous material loading and tanks* refer to sources at production sites that are associated with any materials not expected to be co-products of natural gas processing, such as gasoline, diesel, or lubricating oil. These sources are associated with gas release emissions, which depend on the composition of their identified contents.
- *Condensate and crude-oil-related sources*, including loading areas and storage tanks, are associated with substantial VOCs but occur in the process chain only after the co-products have been separated from the natural gas process chain. Therefore, although these emissions sources sometimes are reported in natural gas emission inventories, they are outside the boundary of this analysis.

Natural Gas Processing Stage

The processing process stage consists of ongoing activities related to converting the extraction production gas to the required quality, composition, and compression of pipeline gas. Activities in this stage include separating the condensate co-product from the gas, removing naturally occurring acid gases such as CO_2, lowering the moisture content of the gas, and pressurizing and heating the gas. These activities can occur at either the wellhead or at separate processing facilities, and they are associated with the following emissions sources:

- *Compressor engines and natural gas turbines* are used to pressurize the gas and power other processing activities. These engines, which typically burn the production gas being processed, are associated with combustion-generated GHG emissions.
- *Boilers and heaters*, which typically burn the production gas being processed, are used for processing activities, including the separation of condensate from natural gas and the reduction of ice crystals in the gas stream. Boilers and heaters are associated with combustion-generated GHG emissions.
- *Amine units*, also known as acid gas removal (AGR) units, remove acid gases, such as CO_2, from the production gas to help bring the gas composition to that required for pipeline gas. Amine units are associated with the release of GHGs through venting.
- *Glycol dehydrators* remove water from the production gas to help bring the gas composition to that required for pipeline gas. Dehydrators are associated with the release of GHGs through venting.
- *Fugitives* occur from the unintentional release of production gas through leaks from equipment and connections throughout the natural gas process chain; therefore, they are identified with a process stage by the type of site at which they are found. Because the precise composition of the fugitive gas cannot be identified, it is assumed that all fugitives consist of production gas.
- *Vents and blowdowns* refer to the intentional release of gas from equipment throughout the natural gas process chain; therefore, they are identified with a process stage by the type of site at which they are found. Because the precise composition of the vented gas cannot be identified, it is assumed that assume all vents and blowdowns consist of production gas.
- *Produced water handling*, including loading areas and storage tanks, is associated with gas release emissions, which are assumed identical in composition to water flash gas.
- *Flares* are combustion-based emission control devices used to convert methane from gas-release emissions into CO_2 from combustion emissions. Flares are used as controls on a variety of gas-release emission sources, including produced-water tanks, condensate tanks, and glycol dehydrators.
- *Miscellaneous material loading and tanks* refer to sources at processing sites that are associated with any materials not expected to be co-products of natural gas processing, such as gasoline, diesel, or lubricating oil. These sources are associated with gas-release emissions, which depend on the composition of their identified contents.

- *Separators* are used for processing oil and natural gas; however, only separators at oil sites vent to the atmosphere. Therefore, separators at sites producing only natural gas and not oil should be associated with no VOC emissions. Although these emissions sources sometimes are reported in natural gas emission inventories, they are outside the boundary of this analysis.
- *Thermal oxidizers* are used for processing natural gas, but only a negligible number are reported in the inventories used because of prohibitive capital costs. Therefore, although these emissions sources sometimes are reported in natural gas emission inventories, they are outside the boundary of this analysis.

Waste Disposal Stage

Natural gas production and processing generates the byproduct of produced water, which must be disposed of because of its high level of contaminants, including salt, hydrocarbons, and various pollutants. Although these activities are associated with stationary and mobile emissions sources, the only tracked emission source for this category is that pertaining to tanks that store the produced water at disposal sites.

Identification of Source Profiles and Attribution to Process Stages

This study identifies the process stage (e.g., production, processing, or transport) to which each source belongs using the provided site names in both inventories. To attribute sources to process stages, the profile associated with each source must first be identified. In the Special Inventory, each source is explicitly identified with the profile under which it was reported to the TCEQ. For the sources in the Point Source Inventory, however, the profile of each source is identified using additional provided information.

The primary source of information for this profile identification is the Source Classification Code (SCC). As described by the TCEQ (2010: p. 90), "A facility's SCC is an eight-digit EPA-developed code that associates emissions determinations with identifiable industrial processes. The TCEQ uses a facility's SCC for modeling, rulemaking, and SIP-related activities; therefore, a facility's SCC must be as accurate as possible. The EPA maintains a current list of SCCs under the 'EIS Code Tables (including SIC)' link at www.epa.gov/ttn/chief/eiinformation.html."

Despite the regulatory importance of the SCC classification, the SCCs provided in the Point Source Inventory do not identify the associated source's profile to the detail necessary for 254 (or 12%) of the 2,177 sources within the 22 counties of the basin. The remaining sources rely on the additional information within characteristics files provided by the TCEQ for specific profiles, such as tanks and engines, and by consistent coding schemes within the Facility Identification Number, which is self-designated by the respondents to the emissions inventory surveys. The study identifies 43 (or 2%) of the sources by characteristics files and 211 (or 10%) by the Facility Identification Number, which represent 1.4% and 2.0%, respectively, of the total VOCs reported for all reported sources within the 22 counties of the basin.

For those source categories that can exist at multiple types of process stages, the default assumption is that a location is a production facility (i.e., a well site), unless the site name ("Lease Name" in the Special Inventory and "Site Name" in the Point Source Inventory) is identifiable as belonging to a facility type associated with the processing stage, such as a processing plant or a compressor station, or with the disposal stage, such as salt-water disposal sites. In addition, four sites identified as disposal by this method are reassigned to production due to non-zero gas-well gas production statistics, which means all sources at those four sites are assigned to production, although some presumably relate to water-disposal activities instead. To the extent that this allocation method introduces an error, that error is not the omissions of emissions from the overall estimates, but rather, the incorrect allocation of total emissions across different process stages.

TCEQ inventory data are available for some pre-production processes, but such data cannot be used for original analysis because it incompletely covers the life cycle stage. Also, literature estimates available for supplementing the original analysis do not segregate between different processes as would be necessary for incorporation with the original analysis.

This study uses site-level allocation to select sources into the processing stage. The same site name in both the Point Source Inventory and the Special Inventory is used to positively identify processing sites, with the default stage for the remaining sites being production. Of the processing sites, following the recommendation of the TCEQ,[149] those that do not have any processing-related sources are designated as transmission sites, and accordingly, are considered outside the boundary of this analysis.

After site-level identification, processing-type sources at production sites are associated with the processing life cycle stage. Such equipment includes heaters, boilers, amine units, and dehydrators. In addition, following Stephenson et al. (2011), this study assumes that all tanks—and therefore, also all loading (which occurs after tanks in the process chain)—belong to the processing stage and not the production stage, regardless of where the tanks are physically located.

To avoid double counting with third-party emission factors for transmission, transmission sites (identified as non-well facilities without any processing equipment) are omitted from the analysis of TCEQ inventory data. Specifically, 833 sources are omitted from the special inventory and point-source inventory analyses as pertaining to transmission. This represents 5% of the total sources from these inventories, or about 10% of the CO_2 and the CH_4 emissions from these inventories.

Spatially Explicit Estimation of Production Gas Composition

An important differentiation of this study's estimation approach from similar studies is that this study attempts to estimate the composition of production gas in a specific area. The methods used in this study improve upon the use of a general gas composition developed from national-level averages by 1) developing a novel gas composition estimate that is specific to a region of interest, but also by (2) further recognizing the spatial heterogeneity of this composition within the 22-county basin. Specifically, this method collects data on speciation of production gas and the flash gas from produced water to calculate the CO_2 and CH_4 emissions from numerous sources in the TCEQ Special Inventory using spatially explicit estimates of gas composition. The following factors come from this speciation:

[149] Personal communication (TCEQ 2012).

f_C == the fraction of carbon in the production gas by mass (unitless)

f_{CO_2}= the fraction of CO_2 in the production gas by mass (unitless)

f_{CH_4}= the fraction of CH_4 in the production gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the production gas by mass (unitless)

MW_{gas} = the molecular weight of the production gas (lb/lb-mole)

HHV = the higher heating value of the production gas (Btu/scf).

These data are collected from supplementary files from the TCEQ's Barnett Shale Phase Two Special Inventory. As part of the quality assurance procedures of this Special Inventory, the TCEQ requested supplementary files from respondents. These files consist of a record of the written correspondence between the respondent and TCEQ, which varies considerably in content and form across different respondents. To estimate gas composition across the Barnett Shale region, this analysis focuses on included reports from independent laboratory analyses of the gas compositions, identifiable as pertaining to relevant samples of either production gas or of leaked gas in the form of vents or gaseous fugitives. Due to the nature and the origin of these files, the inclusion and reporting of such gas content analyses are not consistent across different files. Detailed supporting information—such as the specific origin of the sample tested, both with respect to process and geographic location—is not consistently available; therefore, it cannot be confirmed in many cases.

Given the disparate nature of these files and the inconsistent reporting of identifying information, these analyses therefore omit many reported composition analyses due to a lack of clarity regarding the geographical or process-source of the analyzed sample. Instead, those analyses are retained that can be assigned a location and content type with a reasonable level of confidence. The creation of these supplementary files and selection of a subset of them for obtaining gas composition analyses is neither random nor intended to be representative; therefore, such elimination does not introduce selection bias created by such omissions. The randomness of the errors will lead to attenuation bias of the analytical results, which is typical in cases of measurement error where there is no reasonably expected consistent bias to the error. In this context, measurement error should reduce the impact of calculating the spatial variation in gas content versus using the central estimate of gas content across the entire region.

In a related limitation of this method, we identified a substantial number of duplicate analyses in these records associated with different lease locations and even across different counties, based on identifying identical laboratory-assigned sample numbers and identical compositions to the reported level of precision provided by the same company. We attempted to identify and remove duplicate analyses; but misspecification in the dataset is possible because it is unclear in some cases which analysis is the original source.

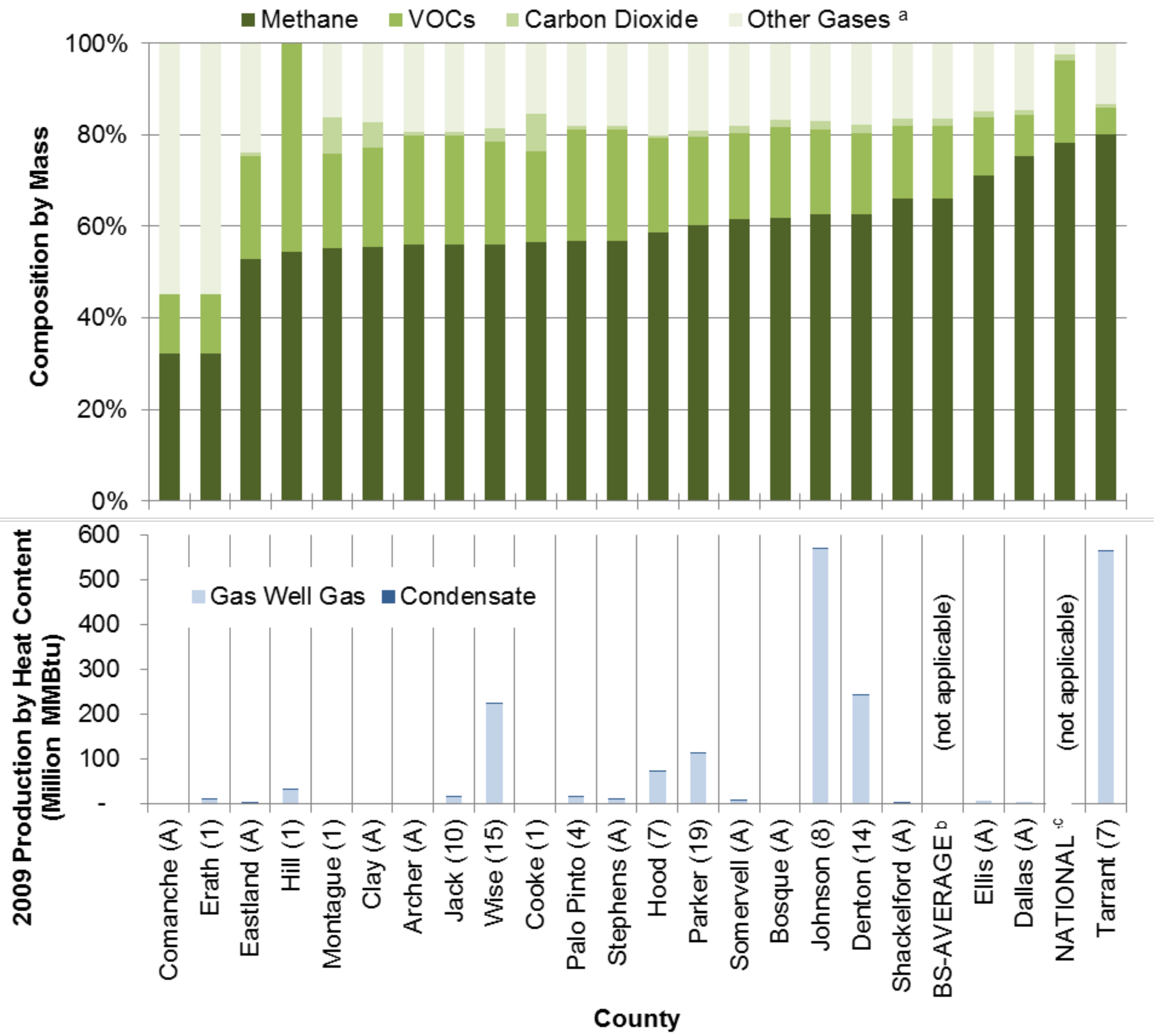
From these data, county-level estimates of gas composition are developed separately for production gas, condensate flash, oil flash, and produced-water flash. Counties with one or more available composition analyses are assigned the composition analysis with the median level percentage-by-weight of methane in the reported composition analyses. In addition to providing a central estimate of gas composition for each county, this estimation of central tendency buffers the results against the impact of misspecifications of location described above.

We used a production-weighted average of the median adjacent counties' estimates with reported composition analyses for counties with no reported composition analyses. A production-weighted average of all reported composition analyses across the Barnett Shale region is used for the few counties with no reported composition analyses either for that county or for all adjacent counties.

In addition to attempting to err on the side of caution in including gas composition analyses, we estimated the sensitivity of the analysis to the gas composition by comparing results of this study's method—which uses the county-level gas composition estimates as described above for emissions estimates—to results using the same emissions estimation calculations with two different sets of alternative gas compositions: one reflecting the production-weighted average of this study's gas analyses from the TCEQ Special Inventory supplementary files and another reflecting standard assumptions of gas composition identified in the literature. Given the imperfect source of information and the assumptions on which this study's analysis depends, substantial variation between these different methods makes a compelling case for the importance of using geographically appropriate gas compositions that are accurate to a reasonably fine scale when estimating GHG emissions from natural gas extraction and production. This study's approach provides the best-available approximation, using the best-available data, of a spatially explicit definition of gas compositions relevant to estimating GHG emissions. To improve on this analysis, future data collection efforts should emphasize the measurement and reporting of spatially explicit gas compositions.

Estimated Composition of Production Gas

The top panel of the Figure 57 presents the estimates of the main components of production gas from each of the 22 counties of the Barnett Shale play, as well as the Barnett Shale production-weighted average and the national average commonly used in the literature. Key parameters and production statistics for each county are also presented in Table 17 and Table 18. Components, which are shown in their mass percentage within the production gas, include methane, VOCs (as defined above to include all non-methane and non-ethane hydrocarbons), CO_2, and other gases. Primary gas species represented in the "other" category are nitrogen and ethane. The lower panel of Figure 57 depicts, for reference, the production volume for each county. Shown after each county's name is the number of unique analyses collected for that county—with counties estimated by a weighted average of adjacent county's compositions designated with an "A," rather than a number.



[a] "Other" gas include nitrogen, ethane, and any other non-methane, -VOC, or -carbon dioxide gases reported
[b] BS-AVERAGE refers to the production-weighted average gas composition in the 22-county Barnett Shale basin
[c] NATIONAL refers to the national average composition commonly used in the literature (EPA 2011)

Figure 57. Composition of production gas by county

NOTE: number of gas composition samples is reported in parentheses following each county name, where "A" denotes counties with no samples such that samples from adjacent counties were substituted.

The gas composition estimates for the six counties that represent the vast majority of production volumes are supported by high numbers of estimates. However, reflecting this study's non-random, targeted strategy for seeking these estimates, many of the estimates for the remaining counties come from either a small number of estimates or the weighted average of adjacent counties. Specifically, no usable estimates were found for 10 of the 22 counties.

The uncertainty inherent to this approach for obtaining gas analyses is highlighted by the difference in gas composition in Comanche County and Erath County versus the majority of the counties. These compositions, which are both estimated by a single analysis from Erath County, show an abnormally large presence of nitrogen—and thus, are suspect of contamination with ambient air. However, the available information offers no verifiable support of such suspicion. The presence of such uncertainty emphasizes the need for better documentation of gas composition if this factor is to be used in further analysis or other factors, such as implementing regulations. However, it is important to note that the very low production volumes associated with these two counties means that their analyses have a nearly negligible impact on the overall results.

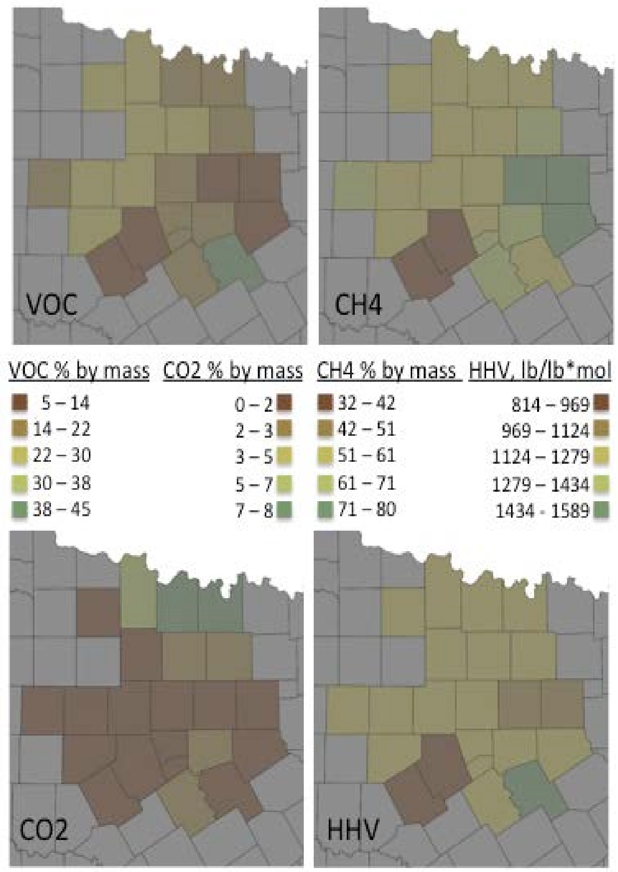


Figure 58. Variation among gas compositions across the 22 counties of the Barnett Shale play

The variation among gas compositions is demonstrated as being patterned across the 22 counties of the Barnett Shale play differently for different key parameters, as shown Figure 58. Such patterned distribution is to be expected if the observed variation reflects geological heterogeneity rather than simply uncertainty in the sampling methodology. The counties represented by weighted averages are located primarily on the western and eastern periphery of the region; therefore, the central north-south corridor represents both the majority of production and the estimates supported by larger samples. Along this corridor, parameters can be observed to vary relatively smoothly, although the differentiation between different parameters demonstrates the complexity of the variation in gas composition. In other words, this map demonstrates that gas composition varies across space, but also, it suggests that the complexity of this variation might extend to finer scales than the county level.

Table 17. Composition of Production Gas and Produced-Water Flash Gas in Barnett Shale Counties

	Production Gas						Produced-Water Flash Gas		
County	Molecular Weight (lb/lb-mole)	Higher Heating Value (Btu/scf)	Carbon Content (% by mass)	Methane (% by mass)	VOCs (% by mass)	Carbon Dioxide (% by mass)	Methane (% by mass)	VOCs (% by mass)	CO_2 (% by mass)
Comanche	23.86	813.78	43.6	32.2	12.9	0.2	33.5	24.8	31.1
Erath	23.86	813.78	43.6	32.2	12.9	0.2	43.1	34.8	7.8
Eastland	22.07	1,188.04	69.3	52.8	22.4	0.7	27.7	52.0	6.4
Hill	26.92	1,589.66	79.2	54.5	45.6	0.0	38.3	5.8	54.8
Montague	21.99	1,216.13	72.6	55.1	20.7	8.1	53.3	17.4	13.0
Clay	21.86	1,229.52	73.2	55.4	21.8	5.5	26.7	6.2	61.1
Archer	21.63	1,253.47	74.2	55.9	23.8	1.0	26.7	6.2	61.1
Jack	21.63	1,253.47	74.2	55.9	23.8	1.0	26.7	6.2	61.1
Wise	21.79	1,274.01	75.5	56.0	22.6	2.9	59.5	19.9	1.9
Cooke	21.76	1,199.75	72.2	56.5	20.0	8.1	46.8	17.2	18.0
Palo Pinto	21.72	1,261.53	74.3	56.9	24.3	0.8	27.7	52.0	6.4
Stephens	21.72	1,261.53	74.3	56.9	24.3	0.8	27.7	52.0	6.4
Hood	21.19	1,248.33	75.2	58.5	20.8	0.6	48.2	29.1	8.2
Parker	20.85	1,242.78	75.9	60.3	19.3	1.2	16.3	52.4	1.1
Somervell	20.71	1,224.89	75.3	61.5	19.0	1.6	40.1	10.0	46.4
Bosque	20.89	1,236.59	75.5	61.7	19.8	1.7	38.3	5.8	54.8
Johnson	20.57	1,226.04	75.8	62.5	18.7	1.8	38.3	5.8	54.8
Denton	20.54	1,218.65	75.4	62.5	17.9	1.9	34.8	14.5	33.3
Shackelford	20.12	1,191.89	74.8	66.2	15.9	1.6	33.5	24.8	31.1
Ellis	19.41	1,159.09	74.6	71.0	12.9	1.3	32.5	19.4	43.2
Dallas	18.63	1,112.74	73.9	75.4	9.0	1.1	23.9	39.5	23.1
Tarrant	17.92	1,072.83	73.3	80.2	5.6	0.9	20.7	46.7	20.1
Barnett Shale Average[a]	20.12	1,191.89	74.8	66.2	15.9	1.6	33.5	24.8	31.1
National Average[b]	17.40	1,027.00	75.0	78.3	17.8	1.5			

[a] Barnett Shale average is a production-weighted average of counties for which original gas compositions could be obtained

[b] National average production gas reported in EPA (2011)

Table 18. 2009 Production Volumes from Barnett Shale Counties

			Heat Content (MMBtu)			
County	**Oil**	**Condensate**	**Casinghead Gas**	**Gas-Well Gas**	**Combined Gas**	**County Total**
Archer	6,018,590	737	458,853	21,351	480,205	6,499,532
Bosque	0	98	0	354,480	354,480	354,578
Clay	3,514,046	37,503	494,346	351,615	845,961	4,397,511
Comanche	31,946	8,046	54,996	513,967	568,963	608,955
Cooke	11,740,372	43,729	4,394,033	485,521	4,879,554	16,663,655
Dallas	0	0	0	4,923,785	4,923,785	4,923,785
Denton	486,574	2,516,461	1,023,276	241,825,407	242,848,683	245,851,717
Eastland	1,491,957	314,574	834,641	3,916,728	4,751,369	6,557,901
Ellis	6,125	0	0	7,552,672	7,552,672	7,558,797
Erath	34,829	218,806	123,445	10,657,734	10,781,179	11,034,814
Hill	7,267	471	0	31,983,129	31,983,129	31,990,868
Hood	16,553	2,660,894	156,109	72,781,121	72,937,230	75,614,677
Jack	3,999,135	878,025	2,261,462	16,294,739	18,556,202	23,433,361
Johnson	0	318,855	0	570,667,212	570,667,212	570,986,067
Montague	11,979,935	34,090	9,682,791	350,290	10,033,081	22,047,106
Palo Pinto	3,232,091	525,481	6,957,154	16,076,018	23,033,172	26,790,743
Parker	73,886	1,672,455	730,069	112,696,107	113,426,176	115,172,517
Shackelford	4,108,140	66,203	849,166	2,234,492	3,083,658	7,258,000
Somervell	0	65,812	0	7,485,891	7,485,891	7,551,704
Stephens	12,811,777	291,120	3,525,626	11,751,922	15,277,548	28,380,445
Tarrant	0	241,264	0	563,514,077	563,514,077	563,755,341
Wise	2,400,875	5,017,491	6,426,006	222,654,526	229,080,532	236,498,898
Basin Total	**61,954,098**	**14,912,113**	**37,971,973**	**1,899,092,788**	**1,937,064,761**	**2,013,930,972**

Co-Product Allocations

In addition to natural gas, the sources reported in the TCEQ inventories are associated with the marketed products of condensate and, in some cases, oil. In fact, gas companies are focusing all of their new investment in areas with wet gas, which has a higher VOC content, for its higher value. The principle of co-product allocation is that when there are multiple valued products from a single system, the burdens of that system should be shared among all products. This study uses energy-based co-product allocation, which weights the burdens (i.e., emissions) of each process by the ratio of energy contained in all co-products that is embodied in the product of interest.

The factor that is applied depends on the relevant life cycle stage of a source. For production sources, we use the finest grain of spatial resolution available. Specifically, emissions for all production sources in the Special Inventory are allocated among condensate, oil, and natural gas products at the *site level* using site-level production statistics, as follows:

$$Allocation_{site} = \frac{\left(Q_{GWgas,s}\right) * HHV_{pipe\ gas}}{\left(Q_{GWgas,s} + Q_{Cgas,s}\right) * HHV_{pipe\ gas} + Q_{oil,s} * HHV_{oil} + Q_{cond,s} * HHV_{cond}}$$

where:

$Allocation_{site} =$ the site-level, energy-basis co-product factor for gas produced by gas wells (unitless)

$Q_{GWgas,s}$ = the volume of gas-well gas produced at the site annually (Mcf)

$Q_{Cgas,s}$ = the volume of casinghead gas produced at the site annually[150] (Mcf)

$Q_{oil,s}$ = the volume of oil produced at the site annually (bbl)

$Q_{cond,s}$ = the volume of condensate produced at the site annually (bbl)

$HHV_{pipe\ gas}$ = the energy content of natural gas product (i.e., pipeline gas)

- 1,027,000 Btu/Mcf for pipeline-quality gas

HHV_{oil} = the energy content of oil

- 5,800,000 Btu/bbl for crude oil[151]

HHV_{cond} = the energy content of condensate

- 5,418,000 Btu/bbl for plant condensate.[152]

As Figure 59 depicts, the majority of these site-level co-product allocation factors are at or close to 1—reflecting the fact that the majority of production within these counties is natural gas. However, Figure 59 also shows that 15% of the sites included within the Special Inventory produce no gas-well gas and, accordingly, the emissions from these sites do not contribute to the total emissions allocated to natural gas.

[150] Note that casinghead gas is a natural gas that is a co-product of oil production (produced by oil wells).
[151] API (2009), Table 3-8
[152] EIA (2011), Appendix A

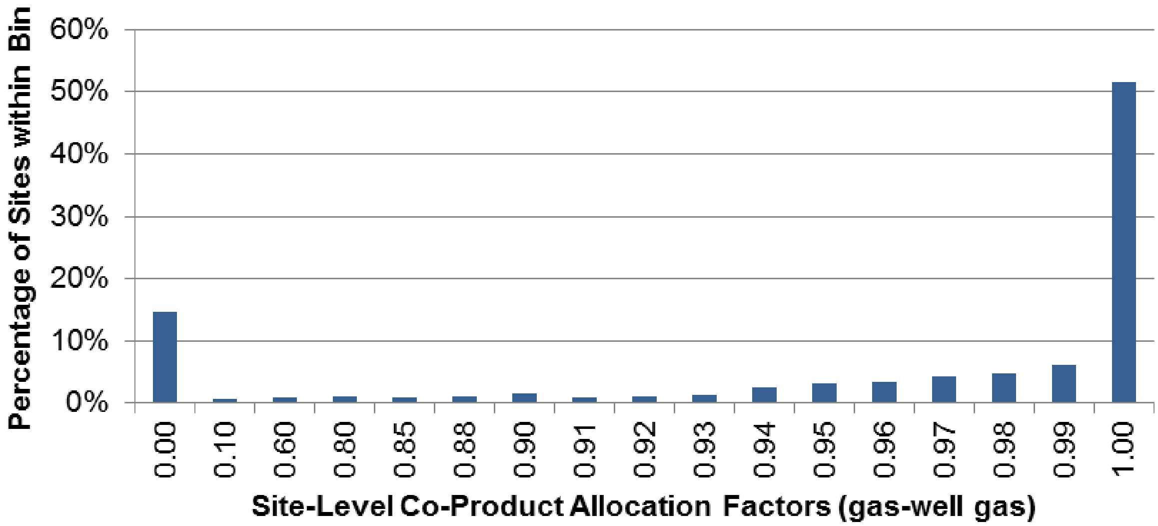


Figure 59. Distribution of site-level emissions allocated to gas

Site-level production statistics are not available for sites in the Point Source Inventory, and relevant counties have negligible oil production, lowering the chance that production-stage point sources emissions are associated with oil production. Therefore, emissions are allocated for all production sources in the Point Source Inventory among condensate and natural gas products at the *county level* using county-level production statistics (Figure 60). Similarly, Area Source Inventory data are available only at the county-level; so they are most appropriately allocated among co-products at this scale. This allocation is calculated as follows:

$$Allocation_{county} = \frac{Q_{GW\ gas,c} * HHV_{pipe\ gas}}{Q_{GW\ gas,c} * HHV_{pipe\ gas} + Q_{cond,c} * HHV_{cond}}$$

where:

$Allocation_{county}$ = the county-level, energy-basis co-product factor for gas (unitless)

$Q_{GWgas,c}$ = the volume of gas-well gas produced in the county annually (Mcf)

$Q_{cond,c}$ = the volume of condensate produced in the county annually (bbl)

$HHV_{pipe\ gas}$ = the energy content of natural gas product (i.e., pipeline gas) (Btu/Mcf)

HHV_{cond} = the energy content of condensate (Btu/bbl).

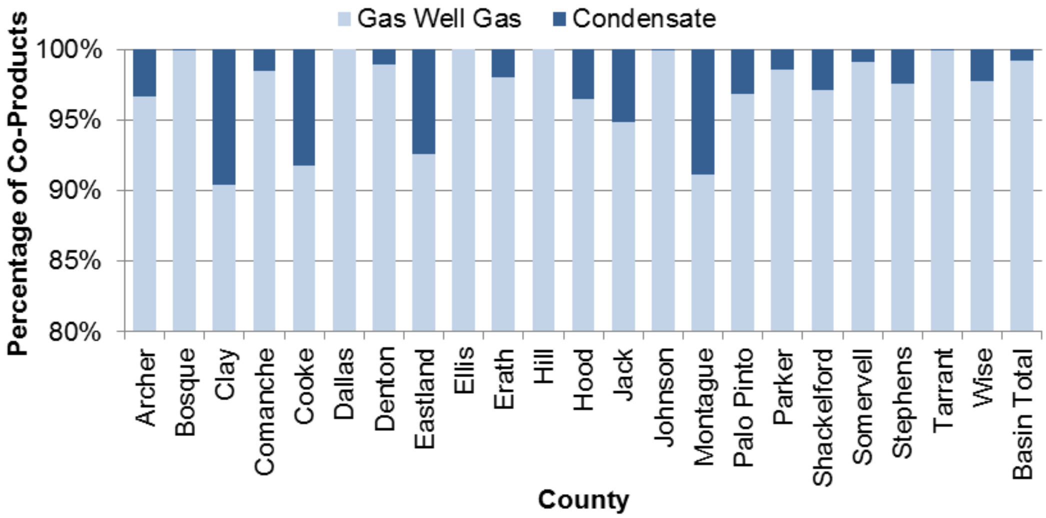


Figure 60. County-level gas production co-products by heat content

Regardless of the inventory in which the sources are described, emissions from processing sources are allocated at the *basin level* using basin-level production statistics, The relevant co-product allocation includes casinghead gas volumes as well as gas-well gas volumes because all natural gas—regardless of whether the production source is a gas or oil well—is processed at these sites. Some of these processing steps might occur after the condensate is separated, but the order of processing steps varies by site and is not identifiable in the data of the TCEQ inventories. Therefore, co-products are allocated as follows:

$$Allocation_{basin} = \frac{\left(Q_{GW\ gas,b} + Q_{Cgas,b}\right) * HHV_{pipe\ gas}}{\left(Q_{GW\ gas,b} + Q_{Cgas,b}\right) * HHV_{pipe\ gas} + Q_{cond,b} * HHV_{cond}}$$

where:

$Allocation_{basin}$ = the basin-level, energy-basis co-product factor for gas (unitless)

$Q_{GWgas,b}$ = the volume of gas-well gas produced in the basin annually (Mcf)

$Q_{Cgas,s}$ = the volume of casinghead gas produced in the basin annually (Mcf)

Q_{cond}, b = the volume of condensate produced in the basin annually (bbl)

$HHV_{pipe\ gas}$ = the energy content of natural gas product (i.e., pipeline gas) (Btu/Mcf)

HHV_{cond} = the energy content of condensate (Btu/bbl).

Note that some processing profiles pertain to processes that might occur after the condensate is separated from the process stream and, therefore, should not be partially allocated to that co-product. However, the specific order of processing steps is not readily identifiable in the data. In addition, the impact of neglecting this is small because condensate contributes less than 1% to the denominator of the allocation factor (Figure 61).

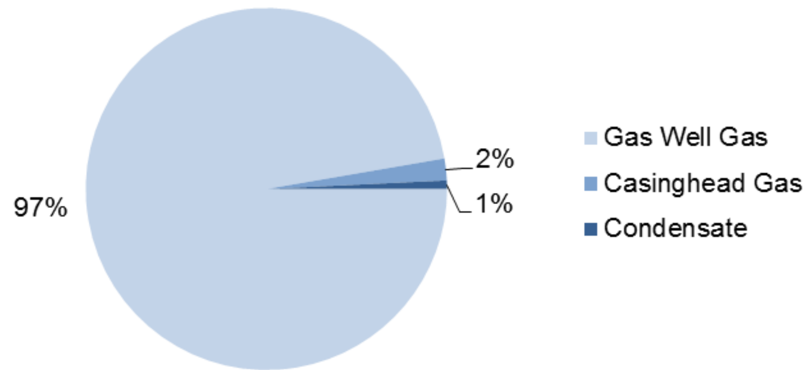


Figure 61. Basin-level gas processing co-products by heat content

In addition, because condensate and crude oil are separately marketable products, co-product allocation means that the substantial VOCs in the TCEQ Inventories corresponding to the storage and handling of these co-products—once separated from the natural gas stream—are outside the boundary of natural gas production and processing. Therefore, this study omits about 25% of the individual sources reported in the two inventories, which collectively represent 60% of the total reported VOC emissions, because they are associated only with the production and processing of the co-products of crude oil and condensate.

Regarding the co-production of oil within the counties of the basin, note that the 84 sites identified as production sites in the Point Source Inventory are all located within the 7 counties listed below—which include their respective percentage of the co-product energy associated with oil production:

- Denton: 0.2% from oil
- Hood: 0.0% from oil
- Johnson: 0.0% from oil
- Palo Pinto: 12.1% from oil
- Parker: 0.1% from oil
- Tarrant: 0.0% from oil
- Wise: 1.0% from oil.

With the exception of Palo Pinto County, these values suggest the co-production of oil represents a negligible amount, and the sole production site in Palo Pinto County identified in the Point Source Inventory is a gas well, associated with zero oil production, as verified through an online query of the Texas Railroad Commission's production statistics database. Therefore, this study does not attribute any production-related emissions from the Point Source Inventory to a co-product of oil.

Overall, 1% of the estimated GHG emissions are allocated to condensate instead of natural gas. For comparison, note that Skone et al. (2011) base their co-product allocation on their reported

12% non-methane VOC whereas Stephenson et al. (2011) report 16.4% allocation to condensate, ethane, and liquid petroleum gas. However, this proportion varies substantially across the 22 counties of the Barnett Shale play, as shown in Figure 62. Even among top-producing counties, which are shown by the larger bars in the lower panel of the figure, significant portions of GHGs are attributed to condensate instead of natural gas—ranging from 0.5% condensate for Johnson County and Tarrant County to 1.7% for Wise County. More strikingly, only 91.7% and 92.7% of emissions in Montague County and Cooke County, respectively, are associated with the natural gas product.

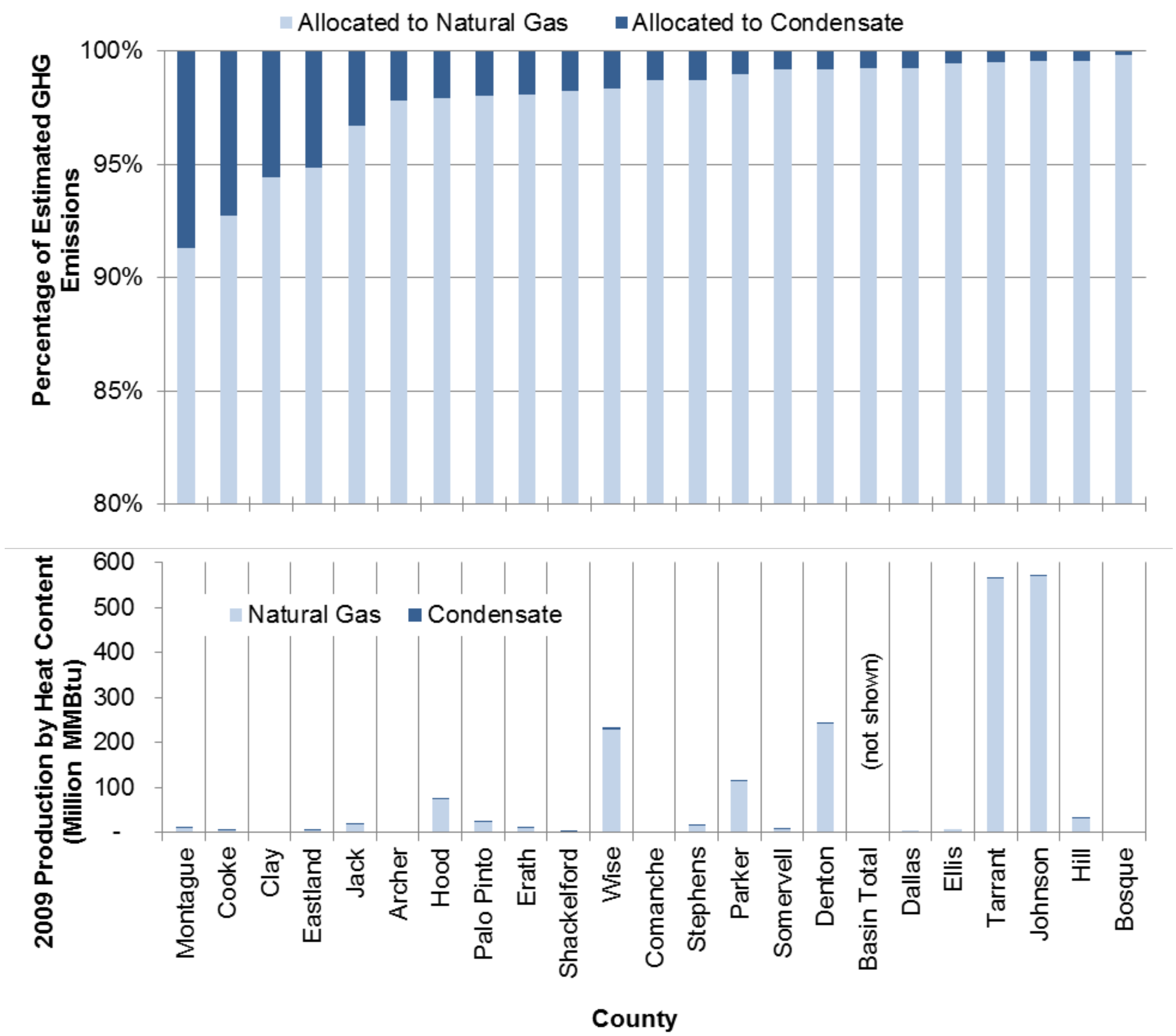


Figure 62. Proportion of GHG emissions associated with co-products

Estimation of Emissions by Source Profile

Emissions estimations generally use a "black box" approach, where a profile is associated with a life cycle stage by the purpose it serves rather than by its physical location. However, for those profiles possibly related to multiple stages, such as compressor engines and fugitives, each source is associated with the life cycle stage by the categorization of the site at which the source is found.

In general, emission sources can be categorized into two broad types of profiles: *combustion sources* and *gas-release sources*, with certain unique characteristics of certain processing activities leading to a third category. A tiered approach is used to calculate emissions, in which secondary calculation methods are applied when the data requirements for preferred methods are not met for an individual source. If neither method is possible with the available data, median estimates from other sources of the same profile are used. Overall, preferred methods were used for 79% of sources, secondary for 18%, and tertiary for the remaining 2%. The following paragraphs introduce the main categories and methodologies, which are adapted from the methodologies presented by ENVIRON (2010), API (2009), and EPA (1995), as appropriate. These emissions estimates include both routine and non-routine emissions estimates for 2009.

Combustion sources include compressor engines, boilers, heaters, and turbines. In these profiles, CO_2 emissions primarily come from chemical reactions during combustion, and methane emissions primarily come from the incomplete combustion of the combusted fuel. The composition of the fuel gas therefore influences the emissions, as do source characteristics and details of the level of usage of the source. This study's preferred methodology for calculating emissions from combustion sources is based on the quantity of fuel combusted and the composition of the fuel gas—as determined by a county-level estimation of production gas composition, assuming that the natural gas fuel used in all cases is the production gas at that site.

Gas leakage sources include both intentional and unintentional releases of gas. Within this category, there is a differentiation between *potentially controllable leakage* and *fugitives*, where the former typically involves gas released from an isolatable emission point and therefore is potentially controllable, and the latter comes from dispersed leaks and therefore is less feasible to control. This study's preferred methodology for calculating GHG emissions from gas-release sources therefore is based on the reported emissions of total VOCs and the ratio of CO_2 and CH_4 to VOCs in the released gas, which means it depends on the speciation of the released gas. Estimating these emissions assumes that production gas is the released gas in all cases, except when the profile is associated specifically with produced water handling; in this case, the released gas is assumed to be equivalent to the produced-water flash gas.

In addition, some processing sources require specialized estimation methods. For example, AGR units specifically remove CO_2 from the production gas. Therefore, this study's method for estimating CO_2 emissions from AGR differs substantially from that used for other profiles. Specifically, AGR units are associated with CO_2 emissions equal to the difference in CO_2 contained within the production gas and that in the final pipeline-quality gas.

The estimation of GHG emissions for different profiles consistently assumes that the speciation of production gas varies spatially based on the geology of the Barnett Shale. This variation can be reasonably represented by variation at the county level, as spatially interpolated from the sample of gas composition analyses collected from supplementary Special Inventory files provided by the TCEQ.

Similarly, all natural gas represented in the following methodologies is assumed to be the production gas, except where explicitly noted (as in the AGR profile calculations). The speciation of this production gas is spatially explicit to the county level for production sources and the basin average composition for processing sources.

In addition, many profiles rely on standardized emission factors, which represent industry-level averages across the specifics of individual equipment. The majority of these emission factors are obtained from the EPA's AP-42, Compilation of Air Pollutant Emission Factors (EPA 1995). Factors applied are shown in Table 19.

Table 19. EPA's AP-42 Compilation of Air Pollutant Emission Factors

Profile	CO_2 Emission Factor	CH_4 Emission Factor	VOC Emission Factor
External Combustion, Natural Gas[a]	118 lb/MMBtu	2.25e-3 lb/MMBtu	5.39e-3 lb/MMBtu
External Combustion, Diesel[b,c]	2710 $kg/10^3m^3$	0.0062 $kg/10^3m^3$	0.0240 $kg/10^3m^3$
Internal Combustion, Natural Gas: 2-Stroke Lean-Burn[d]	110 lb/MMBtu	1.45 lb/MMBtu	1.20e-01 lb/MMBtu
Internal Combustion, Natural Gas: 4-Stroke Lean-Burn[e]	110 lb/MMBtu	1.25 lb/MMBtu	1.18e-01 lb/MMBtu
Internal Combustion, Natural Gas: 4-Stroke Rich-Burn[f]	110 lb/MMBtu	2.30e-01 lb/MMBtu	2.96e-02 lb/MMBtu
Internal Combustion, Diesel	164 lb/MMBtu[g]	3.15e-02 lb/MMBtu[h]	3.19e-01 lb/MMBtu[h]
Internal Combustion, Gasoline	154 lb/MMBtu[g]	1.89e-01 lb/MMBtu[h]	1.911e00 lb/MMBtu[h]
Natural Gas Turbine[i]	110 lb/MMBtu	8.60e-03 lb/MMBtu	2.10e-03 lb/MMBtu
Stationary Large-Bore Diesel Engines[j]	2745 $kg/10^3m^3$	0.1548 $kg/10^3m^3$	1.7415 $kg/10^3m^3$

[a] EPA (1995), Table 1.4-2
[b] Diesel fuel is also used as a proxy for crude oil.
[c] EPA (1995)
[d] EPA (1995), Table 3.2-1
[e] EPA (1995), Table 3.2-2
[f] EPA (1995), Table 3.2-3
[g] EPA (1995), Table 3.3-1
[h] EPA (1995), Table 3.3-1, where total organic compounds from Exhaust = 2.1 for gasoline and total organic compounds from Exhaust = 0.35 for diesel, and Table 3.4-1, which states that total organic compounds by weight is 9% CH_4 and 91% non-CH_4 for the one diesel engine measured
[I] EPA (1995), Table 3.1-2a
[j] EPA (1995)

Tiered Methods Counts

This study applies a tiered approach to the estimation of GHG emissions, in which preferred methods are applied when available data allow, and secondary methods otherwise. For those sources unable to use either method, we apply a tertiary method of assigning the median estimate for that profile. Table 20 demonstrates the count of the usability of each method across the two main inventories.

Table 20. Count of Usability for each GHG Emissions Estimation Method for CO_2 and Methane

	CO_2			Methane		
	Method 1	**Method 2**	**Method 3**	**Method 1**	**Method 2**	**Method 3**
Amine Units	n/a	–	–	4	–	–
Blowdowns and Vents	1,366	68	10	1,366	68	10
Boilers and Heaters	277	–	32	277	–	32
Engines	1,467	364	35	708	1,133	25
Flares	21	–	15	n/a	–	–
Fugitives	4,247	–	24	4,247	–	24
Glycol Dehydrator	79	21	14	79	21	14
Produced-Water Loading	1,948	–	11	1,948	–	11
Produced-Water Tanks	4,429	–	106	4,429	–	106
Special Inventory Total	13,834	453	247	13,058	1,222	222
Engines	–	673	–	–	673	–
Flares	–	17	–	n/a	–	–
Other combustion	–	264	–	–	264	–
Gas Leakage Sources	–	735	–	–	735	–
Produced-Water Tanks	90	–	–	90	–	–
Point-Source Inventory Total	90	1,689	0	90	1,672	0
Combined Total	13,924	2,142	247	13,148	2,894	222

General Leakage Profiles

General leakage profiles include *blowdowns*, *fugitives*, *pneumatics*, and *vents*. Data on blowdowns, fugitives, and vents are obtained from both the Point Source Inventory and the Special Inventory, and data on pneumatics are obtained from the Area Source Inventory. Although these different sources have different causes, they are calculated by similar methods. Because these profiles occur at both production and processing sites, sources are assigned to the stage to which the site belongs.

The primary methods for estimating CO_2 and methane emissions use the reported volume of gas released and this study's estimate of the composition of that gas. Where data are not available on volume of gas released, the secondary method uses the reported volume of VOC emissions and a ratio of the GHG to VOCs in the gas composition. These methods for calculating CO_2 and methane emissions for leakage sources are adapted from ENVIRON's (2010) discussion of leakage sources, including well-completion venting, well blowdowns, permitted fugitives, and unpermitted fugitives.

Note that unlike most profiles, inventory data on pneumatics come from the Area Source Inventory, which provides county-level data without individual source counts. Therefore, although emissions from pneumatics are calculated using methods analogous to other leakage profiles, such calculation occurs at the county level based on aggregated, county-level emissions reported in the inventory.

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = Q_{vented} * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_{CO_2} * \frac{1tonne}{2204.62lb}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

Q_{vented} = the total annual volume of gas emitted through the leakage source (scf/year)

MW_{vented} = the molecular weight of the vented gas (lb/lb-mole)

f_{CO_2} = the fraction of CO_2 in the leaked gas by mass (unitless).

Carbon Dioxide Emissions: Secondary Method

$$E_{CO_2} = E_{VOC} * \frac{f_{CO_2}}{f_{VOC}}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{CO_2} = the fraction of CO_2 in the production gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the production gas by mass (unitless).

Methane Emissions: Primary Method

$$E_{CH_4} = Q_{vented} * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_{CH_4} * \frac{1tonne}{2204.62lb}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

Q_{vented} = the total annual volume of gas emitted through the leakage source (tonne/year)

MW_{vented} = the molecular weight of the vented gas (lb/lb-mole)

f_{CH_4} = the fraction of CH_4 in the leaked gas by mass (unitless).

Methane Emissions: Secondary Method

$$E_{CH_4} = E_{VOC} * \frac{f_{CH_4}}{f_{VOC}}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{CO_2} = the fraction of CO_2 in the production gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the production gas by mass (unitless).

Compression Engines Profile

Data on compressor engines are obtained from the Special Inventory and the Point Source Inventory. Because these profiles occur at both production and processing sites, the sources are assigned to the stage to which the site belongs.

The primary methods for estimating CO_2 and methane emissions use the reported volume of fuel combusted and this study's estimate of the composition of that fuel, as well as the engine characteristics in the case of methane. Where the volume of fuel combusted is not available, the secondary method for CO_2 emissions uses engine characteristics and operations data, some of which is based on standard assumptions; the secondary method for methane emissions uses the reported volume of VOC emissions and a ratio of the GHG-to-VOCs-related, profile-specific emission factors.

In addition to data availability, the secondary method is preferred for sources that failed a simple data-consistency screen, or "ratio test," based on the ratio of reported fuel consumption to an expected gas usage value, calculated as:

$$ratio = \frac{Q_{fuel}}{EFU} = \frac{Q_{fuel}}{MDC * \frac{t_{annual}}{HHV}}$$

where:

$ratio$ = the test value, where any ratio within a factor of 10 of matching (i.e., between 10% and 1000%) is accepted (unitless)

Q_{fuel} = the total annual amount of fuel combusted (MMscf/year)

EFU = the expected fuel usage (MMscf/year)

MDC = the reported maximum design capacity of the engine (MMBtu/hour)

t_{annual} = the annual hours of usage of the engine (hour/year)

HHV = a standardized higher heating value of the fuel, assumed to be 1,150 (Btu/scf).

A final criterion for using the primary method for methane emissions is the reported absence of emissions controls installed on the engine. Ideally, the primary method should be weighted by methane-control efficiency. However, the reported data on VOC control efficiency demonstrate substantial inconsistency, and standardized methane control ratings for engines are not readily available. So, this study assumes that any controls applied affect methane and VOCs equivalently and therefore applies our secondary method for all engines that report the presence of controls. Because the Point Source Inventory does not include information on controls, the secondary method is used, which accounts for the possibility of emissions controls, for all engines in that inventory.

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = Q_{fuel} * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_C * f_O * \left(\frac{44g-CO_2}{12g-C}\right) * \frac{1tonne}{2204.62lb}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

Q_{fuel} = the total annual amount of fuel combusted (scf/year)

MW_{gas} = the molecular weight of the combusted gas (lb/lb-mole)

f_C = the fraction of carbon in the combusted fuel by mass (unitless)

f_O = the fraction of fuel carbon oxidized to CO_2 by mass, assumed to be 1.0 by convention (unitless).

Carbon Dioxide Emissions: Secondary Method

$$E_{CO_2} = HP * LF * f_e * EF_{CO_2} * t_{annual}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

HP = the engine rating (hp)

LF = the load factor of the engine (unitless)

f_e = the energy-basis conversion factor for the engine (Btu/hp-hr)

EF_{CO_2} = the emissions factor of CO_2 on an energy basis (tonne/Btu)

t_{annual} = the annual hours of usage of the engine (hr/year).

Methane Emissions: Primary Method

$$E_{CH_4} = Q_{fuel} * HHV * EF_{CH_4}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

Q_{fuel} = the total annual amount of fuel combusted (scf/year)

HHV = the higher heating value of the fuel (Btu/scf)

EF_{CH_4} = the emissions factor of CH_4 on an energy basis (tonne/Btu).

Methane Emissions: Secondary Method

$$E_{CH_4} = E_{VOC} * \frac{EF_{CH_4}}{EF_{VOC}}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

EF_{CH_4} = the emissions factor of CH_4 on an energy basis (tonne/Btu)

EF_{VOC} = the emissions factor of VOCs on an energy basis (tonne/Btu).

In addition to the standard assumptions described above, these methods depend on the following assumptions:

- The load factor (LF) is assumed to be 0.8 for compressor engines with an engine rating greater than 500 hp and 0.7 otherwise, based on the results of a 2005 study of compressor engines in Texas performed by the TCEQ.[153]
- The energy-basis conversion factor (f_e) for all natural gas internal combustion engines is 7858 Btu/hp-hr.[154]
- The annual hours of usage of the engine (t_{annual}) are 8,760 hr/year for engines without specific usage data, which includes all engines in the Point Source Inventory.
- Any reduction in CO_2 released from the engine related to emissions controls is negligible.

Boilers, Heaters, and Turbines

Data on boilers and heaters are obtained from the Special Inventory, and data on boilers, heaters, and turbines are obtained from the Point Source Inventory. Although turbines substantially differ from boilers and heaters, estimation of emissions follows equivalent methods for all three profiles in the Point Source Inventory. Also, although boilers and heaters can occur at both production and processing sites, they are associated with natural gas processing; therefore, boilers and heaters are assigned to the processing stage.

The primary methods for estimating CO_2 and methane emissions use the reported volume of fuel combusted and this study's estimate of the composition of that fuel. Where the volume of fuel combusted is not available, the secondary method for estimating emissions uses the reported volume of VOC emissions and a ratio of the GHG-to-VOCs-related, profile-specific emission factors.

[153] Personal communication with TCEQ (TCEQ 2012)
[154] ENVIRON (2010), p.84

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = Q_{fuel} * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_C * f_O * \left(\frac{44g-CO_2}{12g-C}\right) * \frac{1tonne}{2204.62lb}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

Q_{fuel} = the total annual amount of fuel combusted (scf/year)

MW_{gas} = the molecular weight of the combusted gas (lb/lb-mole)

f_C = the fraction of carbon in the combusted fuel by mass (unitless)

f_O = the fraction of fuel carbon oxidized to CO_2 by mass, assumed to be 1.0 by convention (unitless).

Carbon Dioxide Emissions: Secondary Method

$$E_{CO_2} = E_{VOC} * \frac{f_{CO_2}}{f_{VOC}}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

EF_{CO_2} = the emissions factor of CO_2 on an energy basis (tonne/Btu)

EF_{VOC} = the emissions factor of VOCs on an energy basis (tonne/Btu).

Methane Emissions: Primary Method

$$E_{CH_4} = Q_{fuel} * HHV * EF_{CH_4}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/year)

Q_{fuel} = the total annual amount of fuel combusted (scf/year)

HHV = the higher heating value of the fuel (Btu/scf)

EF_{CH_4} = the emissions factor of CH_4 on an energy basis (tonne/Btu).

Methane Emissions: Secondary Method

$$E_{CH_4} = E_{VOC} * \frac{f_{CH_4}}{f_{VOC}}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/yr)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

EF_{CH_4} = the emissions factor of CH_4 on an energy basis (tonne/Btu)

EF_{VOC} = the emissions factor of VOCs on an energy basis (tonne/Btu).

Amine Units / Acid Gas Removal

AGR, such as by amine units, removes CO_2 from the production gas. Therefore, this study's method for estimating CO_2 emissions from AGR differs substantially from that used for other profiles. AGR units are associated with CO_2 emissions equal to the difference in CO_2 contained within the production gas and that in the final pipeline-quality gas. Unlike other emissions sources, the CO_2 emissions from amine units are calculated as a single, aggregated basin-wide estimate that does not depend on the number of sources in the inventories.

Specifically, the estimated emissions are estimated as follows:

$$E_{CO_2} = \left[MW_{prod} * f_{CO_2 prod} - MW_{pipe} * f_{CO_2 pipe}\right] * Q_{prod} * \frac{1lb - mole}{379.3\ scf}$$

where:

E_{CO_2} = mass of CO_2 emitted by all AGR sources in the basin annually (tonne/year)

MW_{prod} = the average molecular weight of production gas within the basin (lb/lb-mole)

$f_{CO_2 prod}$ = the average percentage CO_2, by mass, in the production gas (unitless)

MW_{pipe} = the molecular weight of pipeline-quality natural gas[155] (lb/lb-mole)

$f_{CO_2 prod}$ = the average percentage CO_2, by mass, in pipeline gas[156] (unitless)

Q_{prod} = the volume of natural gas produced within the basin annually (scf).

In contrast, methane emissions from AGR are estimated using calculation methods equivalent to those provided in that of General Leakage Sources, as previously discussed.

Dehydrators

GHG emissions from dehydrators are calculated using separate emissions factors depending on the life cycle stage of the site at which the source sites. In the Point Source Inventory, all dehydrators are all at processing sites; but in the Special Inventory, dehydrators exist at both production and processing sites. Therefore, following API (2009), this study uses an emission factor of 275.57 scf/MMscf gas processed for production sites, adjusting the CH_4 content from the 78.8 molar percentage assumed in that reference. Alternatively, if a dehydrator is identified at a processing site, this study uses an emission factor of 121.55 scf/MMscf gas processed and adjusts the molar CH_4 content from 86.8%.

155 Set to 17.4 lb/lb-mole, as provided by EPA (1995) and used by ENVIRON (2010)

156 Set to 0.47%, as per EPA (2011). To the extent that this value overestimates the CO_2 content in pipeline-quality gas, it underestimates CO_2 emissions from acid gas removal, and vice versa.

For those dehydrators identified as having a control present in the Special Inventory, and assuming that all dehydrators in the Point Source Inventory have emission controls, this study assumes a 98% control efficiency for methane and a 0% efficiency for CO_2. Otherwise, this study assumes 0% efficiency of control for both emissions types. The 98% efficiency assumption is supported by standard efficiency assumptions for flares, as well as a reported 97% efficiency for separator-condensers (Schievelbein 1997), an alternative method of control for dehydrators.

Primary Methods

For dehydrators at production sites:

$$E_{CH_4} = P * 0.0052859 * \left[\frac{f_{CH_4,county} * MW_{gas,county}}{16}\right] * \left[\frac{1}{0.788}\right] * (1 - CE)$$

$$E_{CO_2} = P * 0.0052859 * \left[\frac{f_{CH_4,county} * MW_{gas,county}}{16}\right] * \left[\frac{1}{0.788}\right] * \frac{f_{CO_2,county}}{f_{CH_4,county}}$$

and for Dehydrators at Processing sites:

$$E_{CH_4} = P * 0.0023315 * \left[\frac{f_{CH_4,basin} * MW_{gas,basin}}{16}\right] * \left[\frac{1}{0.868}\right] * (1 - CE)$$

$$E_{CO_2} = P * 0.0023315 * \left[\frac{f_{CH_4,basin} * MW_{gas,basin}}{16}\right] * \left[\frac{1}{0.868}\right] * \frac{f_{CO_2,basin}}{f_{CH_4,basin}}$$

where CE = 0.98 if controlled, 0 otherwise, and P is the volume of gas processed. Controls do not affect CO_2 emissions, which are weighted by the ratio of CO_2 to CH_4 (by weight) in the production gas, by county.

Secondary Methods

For Dehydrators without P (which includes all Point Source Inventory dehydrators), the secondary method is based on VOC emissions:

$$E_{CH_4} = E_{VOC} * \frac{f_{CH_4}}{f_{VOC}}$$

$$E_{CO_2} = E_{VOC} * \left(\frac{1}{1-CE}\right) * \frac{f_{CO_2}}{f_{VOC}}$$

Flares

Due to a lack of sufficient information for identifying the specific source to which each flare is associated, this study identifies a flare's process stage by the type of site at which it is found and assumes that all flares combust production gas. This approach will likely overestimate natural gas process-chain emissions due to some of the flares controlling emissions from condensate and crude oil tanks, which should be omitted through co-product allocation; but the overestimation is expected to be small because total flare emissions are small. Only those that can be identified as emissions control for condensate tanks are removed; those that can be identified as combined emissions control for an included profile and condensate tanks are kept. Although this leads to a likely overestimation of emissions from flaring, flares only account for a small proportion of overall emissions, so this overestimation is expected to be small.

For CO_2 emissions, the primary method, which depends on knowing the amount of gas combusted, treats flares equivalently to other combustion sources. The secondary method uses reported VOC emissions and an assumed 98% efficiency to back-calculate the volume of gas combusted. Methane emissions are assumed to be attributed to the original source that is controlled by the flares and therefore are neither calculated nor assigned to this profile.

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = (Q_{waste} + Q_{pilot}) * \left(\frac{1.0lb-mole}{379.3scf}\right) * MW_{gas} * f_C * f_O * \left(\frac{44g-CO_2}{12g-C}\right) * \frac{1tonne}{2204.62lb}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

Q_{waste} = the total annual amount of waste gas combusted (scf/year)

Q_{pilot} = the total annual amount of pilot gas combusted (scf/year)

MW_{gas} = the molecular weight of the combusted gas (lb/lb-mole)

f_C = the fraction of carbon in the combusted fuel by mass (unitless)

f_O = the fraction of fuel carbon oxidized to CO_2 by mass, assumed to be 1.0 by convention (unitless).

Carbon Dioxide Emissions: Secondary Method

$$E_{CO_2} = E_{VOC} * \left(\frac{1}{f_{VOC}}\right) * \left(\frac{1}{1-CE}\right) * f_C * f_O * CE$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{VOC} = the fraction of VOCs in the combusted gas by mass (unitless)

CE = the assumed control efficiency of the flare, 98% (unitless)

f_C = the fraction of carbon in the combusted gas by mass (unitless)

f_O = the fraction of combusted gas carbon oxidized to CO_2 by mass, assumed to be 1.0 by convention (unitless).

Loading and Tanks

For produced-water loading and produced-water tanks, GHG emissions are calculated from VOC emissions and the ratio of VOCs to GHGs in the water flash gas.

Carbon Dioxide Emissions: Primary Method

$$E_{CO_2} = E_{VOC} * \frac{f_{CO_2}}{f_{VOC}}$$

where:

E_{CO_2} = the mass of CO_2 emitted by the source annually (tonne/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{CO_2} = the fraction of CO_2 in the produced-water flash gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the produced-water flash gas by mass (unitless).

Methane Emissions: Primary Method

$$E_{CH_4} = E_{VOC} * \frac{f_{CH_4}}{f_{VOC}}$$

where:

E_{CH_4} = the mass of CH_4 emitted by the source annually (tonne/yr)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/yr)

f_{CO_2} = the fraction of CO_2 in the produced-water flash gas by mass (unitless)

f_{VOC} = the fraction of VOCs in the produced-water flash gas by mass (unitless).

Calculations of Gas Losses from Production and Processing

Gas Release Sources

Profiles reporting gas release sources include amine units, blowdowns, fugitives, glycol dehydrators, and vents.

Natural Gas Lost, Method 1: From Reported Vented Volume

When the volume of gas vented is listed (only for some vents in the Special Inventory), the only calculation is a simple unit conversion, as follows:

$$Q_{NG,lost} = Q_{vented} * \left(\frac{1MM}{1e6}\right)$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

Q_{vented} = the total annual volume of gas emitted from the source (scf/year).

Natural Gas Lost, Method 2: From Reported VOC Emissions

For most gas leakage sources, the volume of gas released is not directly reported. For these, the volume of gas released can be calculated from the amount of VOC emissions, as follows:

$$Q_{NG,lost} = E_{VOC} * \frac{1}{f_{VOC}} * \left(\frac{2204.62lb}{1tonne}\right) * \left(\frac{1}{MW_{gas}}\right) * \left(\frac{379.3scf}{1.0lb - mole}\right) * \left(\frac{1MM}{1e6}\right)$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

f_{VOC} = the fraction of VOCs in the production gas by mass (unitless)

MW_{gas} = the molecular weight of the production gas (lb/lb-mole).

Engines

Engines and other combustion sources (i.e., boilers and heaters) both sometimes include a direct report of the volume of fuel used. But only engines report the characteristics used for the ratio test, described in the section above on compressor engine emissions, and Method 2. Therefore, these combustion sources are calculated differently.

Natural Gas Lost, Method 1: From Reported Volume of Fuel Used

When the volume of gas combusted is listed (only relevant for some Special Inventory sources) and passes this study's Ratio Test for data entry issues, the value can be used directly, as follows:

$$Q_{NG,lost} = Q_{fuel}$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/yr)

Q_{fuel} = the total annual volume of fuel combusted by the source (MMscf/year).

Natural Gas Lost, Method 2: Using Engine Characteristics

The secondary method uses engine characteristics to estimate the amount of fuel used, which is equivalent to the natural gas lost for these sources.

$$Q_{NG,lost} = HP * LF * f_e * \frac{1}{HHV} * t_{anuual} * \left(\frac{1MM}{1e6}\right)$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

HP = the engine rating (hp)

LF = the load factor of the engine (0.8 or 0.7, depending on horsepower)

f_e = the energy-basis conversion factor for the engine (Btu/hp-hr)

HHV = the higher heating value of the fuel (Btu/scf)

t_{annual} = the annual hours of usage of the engine (hr/year).

Non-Engine Combustion

Engines and other combustion sources (i.e., boilers and heaters) both sometimes include direct report of the volume of fuel used. But only engines have the characteristics used both for the Ratio Test and Method 2. Therefore, these combustion sources are calculated differently.

Natural Gas Lost, Method 1: From Reported Volume of Fuel Used

When the volume of gas combusted is listed (which is only relevant for some Special Inventory sources), the value can be used directly, as follows:

$$Q_{NG,lost} = Q_{fuel}$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

Q_{fuel} = the total annual volume of fuel combusted by the source (MMscf/year)

Natural Gas Lost, Method 2: From Reported VOC Emissions

This alternative method only applies to Point Source Inventory non-engine combustion sources:

$$Q_{NG,lost} = E_{VOC} * \frac{1}{EF_{VOC}} * \left(\frac{2204.62lb}{1tonne}\right) * \left(\frac{1}{HHV}\right) * \left(\frac{1MM}{1e6}\right)$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

E_{VOC} = the mass of VOCs emitted by the source annually (tonne/year)

EF_{VOC} = the VOC emission factor for the source (lb/MMBtu)

HHV = the higher heating value of the fuel (Btu/scf).

Methane Lost, for All Sources: Convert from Natural Gas Lost

For all sources, the conversion from estimated natural gas lost to estimated methane lost is completed as shown:

$$Q_{CH_4,lost} = Q_{NG,lost} * \frac{MW_{gas}}{MW_{CH_4}} * f_{CH_4}$$

where:

$Q_{NG,lost}$ = the volume of natural gas lost or used by the source annually (MMscf/year)

$Q_{CH_4,lost}$ = the volume of CH_4 lost or used by the source annually (MMscf/year)

f_{CH_4} = the fraction of CH_4 in the production gas by mass (unitless)

MW_{gas} = the molecular weight of the production gas (lb/lb-mole)

MW_{CH_4} = the molecular weight of CH_4 (16.0 lb/lb-mole).

Summary of Adjustments to Estimated Emissions

Emissions from production sources in the Point Source Inventory are adjusted by allocation across co-products at the county-level, as follows:

$$E_{final} = [E_{raw}] * [Allocation_{county}]$$

where:

E_{raw} = the unadjusted emissions estimate, e.g.,

$$E_{CO_2} = Q_{fuel} * \left(\frac{1.0lb - mole}{379.3scf}\right) * MW_{gas} * f_C * f_O * \left(\frac{44g - CO_2}{12g - C}\right) * \frac{1tonne}{2204.62lb}$$

$Allocation_{county}$ = the county-level allocation of emissions across co-products.

Emissions from production sources in the Area Source Inventory are adjusted by allocation across co-products at the county level and the adjustment for changes in production volumes, as follows:

$$E_{final} = [E_{raw}] * [Allocation_{county}] * [Adjustment_{county}]$$

where:

E_{raw} = the unadjusted emissions estimate

$Allocation_{county}$ = the county-level allocation of emissions across co-products

$Adjustment_{county}$ = the county-level adjustment of emissions from 2008 to 2009 estimates.

Adjustments to emissions from production sources in the Special Inventory differ from this by (1) allocation across co-products at the site-level, rather than at the county-level, (2) requiring site-level and inventory-level corrections, and (3) not requiring the production volume adjustment, as follows:

$$E_{final} = [E_{raw}] * [Correction_{site}] * [Correction_{inventory}] * [Allocation_{site}]$$

where:

E_{raw} = the unadjusted emissions estimate

$Correction_{site}$ = the site-level adjustment factor that accounts for the non-report of sources at the site that are below the reporting threshold for the Special Inventory

$Correction_{inventory}$ = the adjustment factor to all Special Inventory results that accounts for the "98% completion rate" of the inventory reported by the TCEQ

$Allocation_{site}$ = the site-level allocation of emissions across co-products.

Emissions from processing sources in the Point Source Inventory are adjusted by allocation across co-products at the basin-level, as follows:

$$E_{final} = [E_{raw}] * [Allocation_{basin}]$$

where:

E_{raw} = the unadjusted emissions estimate

$Allocation_{basin}$ = the basin-level allocation of emissions across co-products.

Finally, emissions from processing sources in the Special Inventory are adjusted by the inventory-level and site-level corrections and by allocation across co-products at the basin level, as follows:

$$E_{final} = [E_{raw}] * [Correction_{site}] * [Correction_{inventory}] * [Allocation_{basin}]$$

where:

E_{raw} = the unadjusted emissions estimate

$Correction_{site}$ = the site-level adjustment factor that accounts for the non-report of sources at the site that are below the reporting threshold for the Special Inventory

$Correction_{inventory}$ = the adjustment factor to all Special Inventory results that accounts for the "98% completion rate" of the inventory reported by the TCEQ

$Allocation_{basin}$ = the basin-level allocation of emissions across co-products.

Greenhouse Gas Emission Factors

To create emissions factors for process stages, the sum of estimated emissions for sources in each stage is divided by the production volume of gas associated with those emissions. The relevant statistics exist at the county level for production sources and at the basin level for processing sources.

For sources in the production stage, emissions and production can be associated at the county level. This emission factor focuses only on natural gas production from gas wells, omitting the casinghead gas produced as a co-product from oil wells. Specifically, for CH_4 emissions associated with production (and where CO_2 is calculated analogously):

$$EF_{CH_4,prod,i} = \frac{\sum_{n \in N_{prod,i}} E_{CH_4,n}}{Q_{GWgas,i}}$$

where:

$EF_{CH_4,prod,i}$ = the CH_4 emission factor for production in county i (tonne/Mcf)

$E_{CH_4,n}$ = the mass of CH_4 emitted from source n annually (tonne/year)

$N_{prod,i}$ = the set of production sources in county i

$Q_{GWgas,i}$ = the volume of gas produced from gas wells in county i annually (Mcf/year).

For sources in the processing stage, however, emissions and production can only be associated at the basin level because centralized processing sites likely process Barnett Shale gas produced in neighboring counties. In addition, the gas processed by these facilities includes gas produced both from gas wells and oil wells (i.e., casinghead gas), and the denominator includes the sum of these two volumes, accordingly. Specifically, for CH_4 emissions associated with processing (and where CO_2 is calculated analogously):

$$EF_{CH_4,proc} = \frac{\sum_{n \in N_{proc}} E_{CH_4,n}}{Q_{GWgas} + Q_{Cgas}}$$

where:

$EF_{CH_4,proc}$ = the CH_4 emission factor for processing in the basin (tonne/Mcf)

$E_{CH_4,n}$ = the mass of CH_4 emitted from source n annually (tonne/year)

N_{proc} = the set of processing sources in the basin

Q_{GWgas} = the volume of gas-well gas produced in the basin annually (Mcf/year)

Q_{Cgas} = the volume of casinghead gas produced in the basin annually (Mcf/year).

The estimation strategy for the processing stage is exposed to a risk of leakage of production volumes both into and out of the basin, where the former corresponds to emissions caused by the processing of gas not accounted for in the basin's production statistics and the latter to gas included in the production statistics that is not accounted for in the processing emissions because such processing occurs outside the basin. The potential for bias from leakage is expected to be small because of the costs incurred in shipping unprocessed gas unnecessarily, as well as the relatively small amount of production in neighboring counties (the sum of which is only 8% the sum of gas production within the basin). Further, the potential for leakage in both directions increases the likelihood that any bias introduced by one direction of leakage will be cancelled by that in the other direction. But if not completely cancelling, the small scale of production outside the basin suggests that the sum of leakage would be out of the basin, meaning the estimates will underestimate emission factors.

From Inventory to LCA

The final estimate of life cycle GHG emissions is calculated as:

$$EF_{LifeCycle} = \left(\frac{1}{TE}\right) * \left[\frac{EF_{PreProduction}}{L_1} + \frac{EF_{Production}}{L_2} + \frac{EF_{Processing}}{L_3} + \frac{EF_{Transmission}}{L_4} + \frac{EF_{Disposal}}{L_2}\right] + EF_{Combustion} + EF_{Construction} + EF_{Decommissioning}$$

where:

$EF_{LifeCycle}$ = the emission factor for the entire life cycle (g GHG/kWh generated)

TE = the thermal efficiency of the power plant (kWh-equivalent input/kWh generated)

$EF_{PreProduction}$ = the emission factor for all pre-production processes, including completions and workovers, amortized by the lifetime EUR (g GHG/kWh-equivalent extracted)

$EF_{Production}$ = the emission factor for all production processes (g GHG/kWh-equivalent produced)

$EF_{Processing}$ = the emission factor for all gas processing processes (g GHG/kWh-equivalent processed)

$EF_{Transmission}$ = the emission factor for all processed gas transmission processes (g GHG/kWh-equivalent transmitted)

$EF_{Disposal}$ = the emission factor for all produced-water disposal processes (g GHG/kWh-equivalent produced)

$EF_{Combustion}$ = the emission factor for combustion at the power plant, based on the assumed TE (g GHG/kWh generated)

$EF_{Construction}$ = the emission factor for all power-plant construction processes, amortized over the lifetime production of the power plant (g GHG/kWh generated)

$EF_{Decommissioning}$ = the emission factor for all power-plant decommissioning processes, amortized over the lifetime production of the power plant (g GHG/kWh generated)

L_1 = a loss factor representing the portion of gas extracted that remains in the product flow to be used as an input for combustion, reflecting process-chain losses inclusive of this life cycle stage onward (kWh-equivalent extracted/kWh-equivalent input)

L_2 = a loss factor representing the portion of gas produced that remains in the product flow to be used as an input for combustion, reflecting process-chain losses inclusive of this life cycle stage onward (kWh-equivalent produced/kWh-equivalent input)

L_3 = a loss factor representing the portion of gas processed that remains in the product flow to be used as an input for combustion, reflecting process-chain losses inclusive of this life cycle stage onward (kWh-equivalent processed/kWh-equivalent input)

L_4 = a loss factor representing the portion of gas transmitted that remains in the product flow to be used as an input for combustion, reflecting process-chain losses inclusive of this life cycle stage onward (kWh-equivalent transmitted/kWh-equivalent input).

Using this formula, life cycle GHG emissions are estimated as shown in Table 21.

Table 21. Life Cycle GHG Emissions Values (g CO_2e/kWh,100-yr)

		Not Separated	From CO_2	From Methane	Sum Base-EUR	Sum High-EUR	Sum Low-EUR
	EUR (bcf)				1.42	4.26	0.45
Fuel Cycle	Pre-Production (non-completions)[a]		13.9		13.9	4.6	44.6
	Completions and Workovers[b]			20.2	20.2	6.7	65.0
	Production		3.3	3.0	6.3	6.3	6.3
	Processing		15.6	2.4	18.0	18.0	18.0
	Produced Water Disposal		0.0	0.7	0.7	0.7	0.7
	Transmission[c]		3.2	16.2	19.4	19.4	19.4
Power Plant	Construction and Decommissioning[d]	1.2			1.2	1.2	1.2
	Combustion at Power Plant[e]		359.0		359.0	359.0	359.0
Overall	Life Cycle	1.2	395.0	42.4	438.6	415.8	514.1

[a] Although lower estimates for this stage have been published, reported emissions increase as the comprehensiveness of processes considered increase. So we use the highest published estimate for this stage that provided results in a form that could be adjusted by EUR (Santoro et al., 2011).

[b] Based on EPA (2011) estimate of 9,175 Mcf natural gas emission/completion, 1% of wells/year workover rate (EPA 2012b), 30-year assumed lifetime (Skone et al. 2011), and 22-county, Barnett Shale average natural gas molecular weight of 20.1 lb/lb-mol and 66.2% methane by mass.

[c] Based on Skone et al. (2011)

[d] Based on Skone and James (2010)

[e] Based on Skone et al. (2011)

Appendix C: Requirements, Standards, and Reporting

Table 22. State Revisions to Oil and Gas Laws

PA	Updated regulations in 2010. Particular emphasis on well construction, disclosure, handling and disposal of recovered fluids. New 2012 legislation also created new setbacks, environmental impact analysis requirements, new fees, floodplain drilling restrictions, restoration requirements, general containment requirements, public disclosure requirements, restricted local control.
NY	Proposed major overhaul of regulations in 2011 specifically to address high-volume hydraulic fracturing. Some of the most comprehensive rules in the nation. Added new subpart 560 containing definitions specific to high-volume hydraulic fracturing, setback, reporting, well construction, and reclamation standards.
CO	Major overhaul of regulations in 2009. In 2011, revised disclosure rule, added a requirement that operators must notify Commission within 48 hours of intention to fracture and provide landowners within 500 feet of proposed oil and gas location information regarding fracturing and how to collect baseline monitoring.
WY	Updated regulations in 2010. Revised disclosure and pit requirements; strengthened presumptive Best Available Control Technology requirements for air emissions (green completions in Jonah Pinedale Anticline Area and Concentrated Development Areas).
TX	Updated air rules and implemented disclosure rule in January 2012.
LA	Finalized new disclosure rule in October 2011.

Table 23. Fracking Fluid Disclosure Requirements

	Colorado	Louisiana	New York	Pennsylvania	Texas	Wyoming
State Code	COGCC Rule 205A	La. Admin Code. tit. 43, pt. XIX, § 118	Draft SGEIS 8.2.1.1	Act 13, §3222, 3222.1	16 Tex. Admin Code § 3.29	WOGCC Rules, Ch. 3 § 45
Takes Effect	February 1, 2012	October 20, 2011	Proposed 2011	April 16, 2012[157]	February 1, 2012	October 17, 2011
Duty to Report?	Yes. Names of products in fracking fluids, chemicals in fracking fluids, associated chemical abstract numbers.	Yes. Names of products in fracking fluid, chemical ingredients in fracking fluid, chemical concentrations of hazardous chemicals.	Yes. Fracking fluid additive products and material safety data sheets	Yes. Names of products in fracking fluid, chemicals in fracking fluid, associated chemical abstract service numbers.	Yes. Names of products in fracking fluid, chemicals in fracking fluid, associated chemical abstract numbers, volume of fracking fluid.	Yes. Names of products in fracking fluid, chemicals present in fluid, associated chemical abstract service numbers, volume of fracking fluid.
To Whom?	Yes, to Frac Focus provided public can search information by company, chemical ingredient, geographic area, and other criteria by Jan. 1, 2013. If not, COGCC will build its own searchable database. Must also provide landowners within 500 feet of the well with information regarding fracking and baseline water sampling.[158]	Office of Conservation, district manager or Frac Focus	NY Department of Environmental Conservation for public disclosure	PA Department of Environmental Protection or Frac Focus. Similar requirement to CO that Frac Focus must be searchable by Jan. 1, 2013, or DEP may require other form of public disclosure.	Yes, to Frac Focus.	Yes to WOGCC website.

[157] Note, however, that Act is enjoined pending resolution of legal challenge to its constitutionality on other grounds.
[158] 2 CCR 404-1, R. 305.e.(1).A. (2012).

	Colorado	Louisiana	New York	Pennsylvania	Texas	Wyoming
When?	No later than 60 days after completion of fracking operation or no later than 120 days after commencement of fracking operation.	Within 20 days after operations are complete.	Prior to drilling.	Within 60 days of completion of well completion	On or before date operator submits Well Completion Report; operator must also upload required information to Disclosure Registry.	Before fracking begins (APD) and after operation is complete (Well Completion Report Form).
Trade Secret Exemption?	Yes, for chemicals but not for chemical family name.	Yes, for chemicals but not for chemical family.	Yes, but must still disclose information regarding properties and effects of hazardous chemical.	Yes, for chemicals but not for chemical family. Claims governed by PA's "Right to Know" law, which requires companies submit trade secret information to the DEP. Citizens may challenge information.	Yes, for chemicals but not for chemical family.[159]	Yes, operator can make a request to WOGCC to keep proprietary information confidential.
Trade Secret Disclosure?	Yes, trade secrets must be disclosed to medical professional in event of medical emergency, to Commission to respond to a spill, release or complaint or if needed for diagnosis or treatment of exposed individual. Disclosure must be kept confidential.	Yes, if required to be provided to a health care professional, doctor, or nurse.	Yes to health professionals, employees and designated representatives.	Yes, if required to be provided to a health care professional in event of an emergency. Disclosure must be kept confidential.	Yes, to health professionals and emergency responders to diagnose, treat, or otherwise respond to an emergency. Disclosure must be kept confidential.	No.

[159] The Texas law contains provisions that allow landowners on whose property operations are taking place, landowners with adjacent property to operations, or state departments and agencies with jurisdiction over matters relevant to trade secret information to challenge a claim of trade secret.

Table 24. Water Acquisition Requirements

Play/Basin	Permit for Withdrawal	Reporting	Other Requirements	Recycling
North San Juan (Colorado)	Permit for groundwater withdrawal outside designated ground water basin.[160]	Must report total volume of water used in fracking job to Frac Focus.[161]	Local requirements apply.[162]	None.[163]
Upper Green River (Wyoming)	Yes[164]	Yes, limited to amount, not source.[165]	None identified.	None.
Marcellus (New York)	Yes[166]	Operator must identify source of water in permit and report annually on aggregate amounts withdrawn or purchased.[167]	Monitoring and other requirements to ensure no degradation to water quality and quantity.[168]	Must develop a wastewater source reduction strategy identifying the methods and procedures operators will use to maximize recycling and reuse of flow back or production fluid either to fracture other wells or for approved beneficial uses.[169]

[160] C.R.S. §§ 37-90-137, 37-92-308 (2011). See also http://cogcc.state.co.us/Library/Oil_and_Gas_Water_Sources_Fact_Sheet.pdf. The Colorado Ground Water Commission may define and alter designated groundwater basins within the state based on adequate factual information. See C.R.S. §37-90-106 (2012).
[161] COGCC R. 205A(b)(2)(A)(viii) (2012).
[162] See, for example, Archuleta County Land Use Code Section 9.2: Archuleta County's Oil and Gas Development Permit Provisions (Amended Dec. 2010) http://www.archuletacounty.org/Planning/Section%209%20-%20Mining%20December%202010.pdf.
[163] *See* Response of the Colorado Oil and Gas Conservation Commission to the STRONGER Hydraulic Fracturing Questionnaire, 32, http://cogcc.state.co.us/Library/HydroFracStronger/COGCC_Response_To_STRONGER_06132011.pdf (noting that R. 907(a)(3) encourages recycling by encouraging operators to submit waste management plans that may provide for reuse of waste water. Rules 903 and 907 encourage recycling by providing for multi-well pits. R. 902.e and 903.a.(4) creates new pit classification for multi-well pits. "These pits are often centrally located in the oil or gas field, are used to store fluids from multiple wells, and may include treatment areas where fracturing flowback fluids and produced water can be brought up to specifications. COGCC is also working with several operators on waste sharing plans that will facilitate the reuse and recycling of fracturing fluids and produced water."
[164] National Conference of State Legislatures, "State Water Withdrawal Regulations," http://www.ncsl.org/issues-research/env-res/state-water-withdrawal-regulations.aspx.
[165] Conversation with Rick Marvel, engineer, WOGCC, May 29, 2012.
[166] NYSGEIS § 7.1.1.1. Withdrawal permits will include conditions to monitor and enforce water quality and quantity standards and requirements. If withdrawing from within 500 feet of wetlands, must require monitoring during pump test. Lowering groundwater levels at or below wetlands is a significant impact triggering site-specific State Environmental Quality Review Act review. Withdrawals from groundwater within 500 feet of private wells also trigger site-specific State Environmental Quality Review Act reviews.
[167] *Id*.
[168] See *Id* (discussing various standards such as passby flow requirements, water conservation practices, and protections for aquatic life that may be included by permit).
[169] NYSGEIS § 5.12.

Play/Basin	Permit for Withdrawal	Reporting	Other Requirements	Recycling
Marcellus (Pennsylvania)	Cannot withdraw without approved water management plan.[170]	Report list of water sources used under approved water management plan and volume of water.[171]	Water management plan that includes plan for reuse of fluids.[172]	Water management plan must include plan for reuse of fluids used to fracture wells.[173] Well completion report must include total volume of water recycled.[174]
Haynesville (Louisiana)	None identified.	Must report water source and volumes after completion or recompletion.[175]	None.	Regulations recognize processing of E&P waste into reusable materials as alternative to other means of disposal and authorizes commercial facilities for the purpose of generating reusable material.[176]
Eagle Ford (Texas)	Yes.[177]	Report total volume of water used in fracking to Frac Focus.[178]	None identified.	None.
Barnett (Texas)	Yes.	Report total volume of water used in fracking to Frac Focus.[179]	None identified.	None.

[170] 58 PA Con. Stat. ch. 32, § 3211(m). Condition of all permits to hydraulically fracture natural gas wells in unconventional formations.
[171] *Id*. § 3222(b.1)(1)(vi) (2012).
[172] 58 PA Con. Stat. ch. 32, § 3211(m). Operators must develop water management plan, which must be approved by DEP, governing withdrawals or use of water. Approval of plan is contingent on determination that withdrawal/use will not adversely affect quantity or quality of water, will protect and maintain designated and existing uses of water supply, will not cause adverse impact to water quality in watershed and will include a reuse plan for fluids for hydraulically fractured wells. If plan is operated in accord with conditions established by the Susquehanna River Basin Commission, the Delaware River Basin Commission or the Great Lakes Commission, it is presumed to meet above conditions.
[173] 58 PA Con. Stat. ch. 32, §. 3211(m)(2)(iv).
[174] *Id.* § 3222(b.1)(1)(vi) (2012).
[175] Well History and Work Resume Report, Form WH-1, Louisiana Hydraulic Fracturing State Review, 5 (March 2011), http://www.strongerinc.org/documents/Final%20Louisiana%20HF%20Review%203-2011.pdf.
[176] La. Admin. Code tit. 43:XIX, § 565 (2010).
[177] Tex. Water Code, tit. 2, ch. 11. *See also* http://www.rrc.state.tx.us/barnettshale/wateruse.php Short-term permits issued by Texas Commission on Environmental Quality Regional Offices and permits for more than 10 acre-feet of water or for a term lasting more than 1 year are issued by the Commission's Water Rights Permitting Team.
[178] 16 Tex. Admin. Code § 3.29(c)(2)(A)(viii) (2011).
[179] *Id*.

Table 25. Well Construction Standards

Play/Basin/ Jurisdiction	Cement Bond Log	Minimum Surface Casing Depth	Pressure Tests for Casing	Monitor Bradenhead Annulus Pressure
Federal Lands[180]	Yes.	None.	Yes. Mechanical integrity test required before each well stimulation operation.	No. But must continuously monitor and record pressure during well stimulation and notify if annulus pressure increases by more than 500 lbs per square inch.
North San Juan (Colorado)	Yes. Required on all production casing, or in the case of production liner, the intermediate casing.[181]	None specified in rules, but OGCC requires casing be set at least 50 feet below aquifer to ground surface.	Yes. Must test production casing during completion and production. [182]	Must monitor and record bradenhead annulus pressure during fracking and notify COGCC of conditions indicating fracking fluids have escaped producing reservoir.[183]
Upper Green River (Wyoming)	No specific requirement.[184]	None specified but casing must be run below known or reasonably estimated utilizable fresh water levels.[185]	No. Mechanical integrity tests may be required but not mandatory.[186]	No
Barnett (Texas)	No.	None specified but all usable-quality water zones be isolated and sealed off to effectively prevent contamination or harm.[187]	All casing must be steel casing that has been hydrostatically pressure tested with an applied pressure at least equal to max. pressure to which pipe will be subjected in the well	All wells must be equipped with a bradenhead. Must notify district office when pressure develops between any two strings of casing. Must perform a pressure test with bradenhead if well shows pressure on the bradenhead.[188]

[180] BLM (2012). "Proposed Rule: Oil and Gas; Well Stimulation, Including Hydraulic Fracturing, on Federal and Indian Lands," Department of Interior, May 4, 2012, http://www.doi.gov/news/pressreleases/loader.cfm?csModule=security/getfile&pageid=293916.
[181] COGCC R. 317(o).
[182] *Id*. at 317(j).
[183] *Id*. at 341.
[184] WOGCC Rules, ch. 3, §§ 12, 21, requires submission of well logs, which includes "electrical, radioactive, or other similar log runs," which may, but does not necessarily, include cement bond logs.
[185] *Id.* § 22(a)(i).
[186] *Id.* § 45.
[187] 16 Tex. Admin. Code § 3.13.
[188] *Id.* § 3.17.

Play/Basin/ Jurisdiction	Cement Bond Log	Minimum Surface Casing Depth	Pressure Tests for Casing	Monitor Bradenhead Annulus Pressure
Eagle Ford (Texas)	No.	None specified but all usable-quality water zones must be isolated and sealed off to effectively prevent contamination or harm.[189]	All casing must be steel casing that has been hydrostatically pressure tested with an applied pressure at least equal to the maximum pressure to which pipe will be subjected in the well.	All wells must be equipped with a bradenhead. Must notify district office when pressure develops between any two strings of casing. Must perform a pressure test with bradenhead if well shows pressure on the bradenhead.[190]
Haynesville (Louisiana)	Yes, operator must run cement bond log, temperature survey, X-ray log, density log, or other acceptable test.[191]	None.[192]	Surface, intermediate, and producing casing must be tested depending on their depth.[193]	No.
Marcellus (New York)	Department may require a cement bond long or other measures to ensure adequacy of the bond.[194]	Must be set to at least 75 feet beyond deepest fresh water zone or bedrock, whichever is deeper.	No.[195]	No.
Marcellus (Pennsylvania)	In response to a potential natural gas migration incident, the department may require operator to evaluate adjacent oil and gas wells with different measures, including cement bond logs.[196]	Must be set 50 feet below deepest fresh groundwater or at least 50 feet into consolidated rock, whichever is deeper.[197]	Yes. New casing must have an internal pressure rating that is at least 20% greater than anticipated maximum pressure to which casing will be exposed. Used casing must be pressure tested after cementing and before continuation of drilling.[198]	No.

[189] *Id*. § 3.13.
[190] *Id*. § 3.17.
[191] La. Admin. Code, tit. 43, pt. XIX, §419(A)(3).
[192] *Id*. § 109.
[193] *Id*.
[194] N.Y. Comp. Codes R. & Regs. tit. 6, ch. V, §559.6(d)(2).
[195] *Id*. § 557.2.
[196] 25 Pa. Code § 78.89.
[197] *Id*. § 78.83.
[198] *Id*. § 78.84.

Table 26. Baseline Monitoring Requirements

Play/Basin	Requirement
North San Juan (Colorado)	Operators drilling within 301–2,640 feet of surface water intended to be used for drinking water must collect baseline water samples from the surface water prior to drilling and 3 months after the conclusion of drilling or completion.[199] Operators must collect water well samples from nearby wells prior to drilling, as well as 1, 3, and 6 years after completion.[200] Operators must provide landowners within 500 feet of proposed oil and gas location with instruction as to how to collect baseline water samples.[201]
Marcellus (New York)	Operator must make reasonable attempt to sample and test all residential water wells within 1,000 feet of a wellpad; must be sampled prior to commencing drilling. If no well is located within 1,000 feet, or the surface owner denies permission, then the operator must sample all wells within a 2,000-foot radius. Monitoring continues at specified intervals as determined by the DEC.[202]
Marcellus (Pennsylvania)	PA law provides for a rebuttable presumption that a well operator is responsible for pollution of a private or public water supply if the supply is within 2,500 feet of an unconventional well and the pollution occurred within 12 months of the later of the completion, drilling, stimulation or alteration of the well. Operators can overcome this presumption by undertaking a pre-drilling or pre-alteration survey that demonstrates pre-existing contamination or if landowner or water purveyor refuses to allow the operator to test.[203]

[199] 2 Colo. Code Regs. § 404-1; COGCC R. 317B(d)(e). Samples must be tested for BTEX, TDS, metals, and other specified parameters in the rules.
[200] Various Commission Orders. *See* COGCC Response to STRONGER, 4, available at http://cogcc.state.co.us/Library/HydroFracStronger/COGCC_Response_To_STRONGER_06132011.pdf. R. 608 extends the requirements set forth in Commission Orders to other parts of the state with CBM wells and requires operators to identify all plugged and abandoned wells within ¼ mile of proposed CBM well, assess the risk of leaking gas or water, make a reasonable good-faith effort to conduct pre-production soil gas survey of all plugged and abandoned wells within ¼ mile of proposed CBM well and post-production survey 1 and every 3 years after production has commenced, and sample water wells located within ¼ or ½ mile from proposed CBM well and within 1, 3, and 6 years thereafter.
[201] 2 Colo. Code Regs. § 404-1; COGCC R. 305.e.(1).A. (2012).
[202] N .Y. Comp. Codes R. & Regs. tit 6, § 560.5(d).
[203] 58 Pa. Cons. Stat § 3218(c).

Table 27. Closed-Loop or Pitless Drilling Requirements

Play/Basin	Requirement	Date Adopted
North San Juan (Colorado)	Pitless drilling within 301–500 feet of surface water intended to be used for drinking water. Pitless drilling or containment of all flowback and stimulation fluids in liner pits within 501–2,640 feet of surface water intended to be used for drinking water unless operator can demonstrate pit will not adversely affect waters.[204]	2008
Upper Green River (Wyoming)	Closed system required where groundwater is less than 20 feet below surface.[205]	2010
Marcellus (New York)	Closed-loop tank system for drilling fluids and cuttings produced from horizontal drilling unless an acid rock drainage mitigation plan for on-site burial of such cuttings is approved by department.[206] Cuttings contaminated with oil-based mud or polymer-based mud must be contained and managed in a closed-loop tank system.[207]	Proposed 2011
Marcellus (Pennsylvania)	Prohibits storage and disposal of production fluids and brine in pits unless permitted under Clean Streams Law.[208]	2010
Barnett (Texas)	Closed-loop mud system required for all drilling and reworking operations unless operations located on open space of at least 25 acres and not within 1,000 feet of residence or certain public places.[209]	2009

[204] COGCC R. 317B(d)(1), (e)(1); R. 904. Colorado does not define pitless drilling. The definition of *pit* is a "natural or man-made depression in the ground used for oil or gas exploration or production purposes. Pit does not include steel, fiberglass, concrete or other similar vessels which do not release their contents to surrounding soils." COGCC R. 100.

[205] WY ADC Oil Gen. ch. 4, § 1(u). Commission has authority to require closed system in other instances to protect surface and ground water, human beings, wildlife and livestock. *Id*. Closed system "includes, but is not limited to, the use of a combination of solids control equipment (e.g., unconventional shakers, flow line cleaners, desanders, desilters, mud cleaners, centrifuges, agitators, and necessary pumps and piping) incorporated in a series on the rig's steel mud tanks, or a self-contained unit that eliminates the need for a reserve pit for the purpose of dumping and dilution of drilling fluids for the removal of entrained drilling solids. A closed system for the purpose of the Commission's rules does not automatically include the use of a small pit, even to receive cuttings." WY ADC Oil Gen. ch.1, § 2(k).

[206] NY Dept. of Envtl Conservation Proposed Rules, 6 N.Y. Comp. Codes R. & Regs. § 560.6. Closed-loop drilling system means a pitless drilling system where all drilling fluids and cuttings are contained at the surface within piping, separation equipment and tanks. 6 N.Y. Comp. Codes R. & Regs. § 750-3.2.

[207] New York Department of Environmental Conservation Proposed Rules, 6 N.Y. Comp. Codes R. & Regs. § 560.7.

[208] PA Office of Oil and Gas Mgmt. Rules, ch. 78.57.

[209] Fort Worth, Tex. Ordinance, § 15-42(A)(3), (A)(38)(b) (2009).

Table 28. Produced Water Disposal

State	Direct	Indirect	Underground Injection Control	Ponds	Land	Reuse
CO	Yes, if water meets criteria for wildlife or agricultural propagation. CBM discharges via permit.[210]	Yes	Yes	Yes	Yes, water must meet state water-quality standard for agricultural/livestock use.[211]	Encouraged[212]
WY	Yes, if water meets criteria for wildlife or livestock watering or other agricultural uses.[213]	Yes	Yes	Yes	Yes, with permission.[214]	Encouraged[215]
TX	Yes[216]	No[217]	Yes	Yes, with permit.[218]	No[219]	No provisions
PA	No	Yes, for new and expanded discharges meeting standards.	Yes	Yes	Yes[220]	Yes[221]
NY	No	Yes operator must analyze POTW capacity and create contingency plan if the primary wastewater disposal is at POTW.	Yes[222]	No	Only with permission.[223]	Encouraged[224]

[210] Colorado follows national effluent limitations. 2 Colo. Code Regs. §404-1; COGCC R. 907.
[211] 2 Colo. Code Regs. §404-1, COGCC R. 907. Standard is 3,500 mg/l.
[212] No specific requirements but COGCC R. 907(a)(3) encourages recycling by encouraging operators to submit waste management plans which may provide for reuse of waste water, see http://cogcc.state.co.us/Library/HydroFracStronger/COGCC_Response_To_STRONGER_06132011.pdf
[213] WY Water Quality Rules & Regs, ch. 2, appendix H. *See also* WOGCC Rules, ch. 4 §1 (ee).
[214] WOGCC Rules, ch. 4 §1 (mm)
[215] *Id.* § 1(z). No specific requirements although "Commission encourages the recycling of drilling fluids and by administrative action approves the transfer of drilling fluids intended for recycling.
[216] Personal communication with John Becker, Texas Railroad Commission.
[217] Based on conversation with Phillip Urbany, engineer, TX Commission on Environmental Quality, May 29, 2012.
[218] 16 Tex. Admin. Code §3.8(d)(2).
[219] Our research did not identify any prohibition on land application but also no clear authorization.
[220] 25 Pa. Code §78.63.
[221] AB 13, Sec. 3211(m).

State	Direct	Indirect	Underground Injection Control	Ponds	Land	Reuse
LA	No[225]	Discharge to a POTW is not a permissible disposal method for produced water in Louisiana.[226]	Yes	Yes	Yes[227]	No provisions

[222] N.Y. Comp. Codes R. & Regs. tit. 6, §750-1.24. *See also* 40 C.F.R. 144 & 146.
[223] Revised SGEIS at 7-60: Those wanting to road spread production brine must petition for a beneficial use determination. NORM concentrations in Marcellus Shale likely won't allow road spreading of brine, but "[a]s more data becomes available, it is anticipated that petitions for such use will be evaluated by the Department."
[224] Proposed N.Y. Comp. Codes R. & Regs., tit. 6, §560.7. Removed pit fluids must be disposed, recycled or reused as described in approved fluid disposal plan. Operator must submit fluid disposal plan (see regs at 750. 3.12).
[225] EPA National effluent limitation, *see* 40 CFR ch. I, subch. N; see also http://www.deq.louisiana.gov/portal/Portals/0/planning/Permits%20Docs/Timeline022912mcm-Version%204.pdf (discharges prohibited onto vegetated areas, soil, intermittently exposed sediment surface, lakes, rivers, streams, bayous, canals, or other surface waters regionally characterized as upland, freshwater swamps, freshwater marshes, natural or manmade water bodies bounded by freshwater swamp/marsh).
[226] *See* La. Admin Code titl. 43, pt. XIX, §313.
[227] *Id*. §313(D).

Table 29. Green Completion Requirements

Play/Basin/Jurisdiction	Requirement	Flaring/Venting Allowed	Local
Federal[228]	Hydraulically fractured gas production wells must capture and route all saleable gas to a sales line during flowback starting in 2015. Exception for low-pressure wells. Does not apply to exploratory or delineation wells.	Pit flaring allowed until 2015 and thereafter allowed for non-recoverable gas. Venting allowed where flaring presents safety hazard or if flowback is noncombustible.	N/A
North San Juan (Colorado)[229]	Must use green completion practices to route saleable gas to sales line as soon as practicable. Does not apply to low-pressure or wells with less than 500 MCFD of naturally flowing gas. Exception for exploratory wells and wells not sufficiently proximate to sales lines.	Gaseous phase of non-flammable effluent may be flared or vented until flammable gas is encountered for safety reasons. During upset conditions. If variance granted.	Cannot vent or flare well directly to atmosphere without first going to separation equipment or portable tank.[230]
Upper Green River (Wyoming)[231]	Must eliminate VOCs and hazardous air pollutants to the extent practicable by routing liquids to tanks and gas to sales line or collection system. Does not apply to exploratory wells.	Permitted when required by specific operational events or circumstances.	None

228 U.S. EPA, Final Rule, Oil and Natural Gas Sector: "New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews," (2012).
229 COGCC R. 805(b)(3).
230 Archuleta County Land Use Code Sec. 9.2.6.3: Archuleta County's Oil and Gas Development Permit Provisions (Amended Dec. 2010) http://www.archuletacounty.org/DocumentView.aspx?DID=295.
231 Wyoming Oil and Gas Production Facilities, ch. 6, § 2 Permitting Guidance (March 2010), http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf.

Play/Basin/Jurisdiction	Requirement	Flaring/Venting Allowed	Local
Barnett (Texas)	None	N/A	All wells that have a sales line must use techniques or methods that minimize the release of natural gas and vapors to the environment during flowback except wells permitted prior to July 1, 2009, or the first well on a pad site.[232]
Marcellus (New York) – *Proposed*	REC whenever sales line available.[233]	Yes, if no sales line available.	None identified

[232] Fort Worth, Tex., Ordinance No. 18449-02-2009, § 15-42(A)(28).
[233] Proposed mitigation requirement via permit condition. New York Department of Environmental Compliance, Revised Draft SGEIS, §7.6.8.

Table 30. Setback Requirements

Play/Basin	State-Distance from home	State-Distance from Private Water Well	State-Distance from source of drinking water	Local	Vertical fragmentation?
Barnett (Texas)	200 feet[234]	None	None	600 feet from home, 200 feet to fresh water well[235]	Yes
Eagle Ford (Texas)	200 feet	None	None	500 feet from home,[236] 200 feet from home[237]	Yes
Haynesville (Louisiana)	500 feet[238]	None	None	None	No
Marcellus (Pennsylvania)	500 feet[239]	500 feet[240]	1,000 feet[241]	200 feet from home or water well[242]	Yes, under current law[243]
Marcellus (New York)	None	500 feet[244]	500 feet[245]	N/A[246]	Yes, in that localities have banned development altogether, and if the state moratorium is lifted, it seems likely localities will attempt to regulate this area

[234] Tex. Local Gov't Code 253.005(c).
[235] Fort Worth, Tex.; Ordinance No. 18449-02-2009.
[236] City of Burleson, Tex., Ordinance B-790-09.
[237] Fayette County, Tex., Ordinance. Local zoning ordinance provides for the same 200-foot setback limit from residential homes but ordinance notes "Zoning Hearing Board may attach additional conditions to protect the public's health, safety, and welfare, including increased setbacks."
[238] State of La. Office of Conservation, Order No. U-HS (Aug. 1, 2009),http://dnr.louisiana.gov/assets/docs/news/2009/U-HS.pdf. *See also Louisiana Hydraulic Fracturing State Review,* (Mar. 2011), 5.
[239] Act 13, § 3215(a) (Unconventional wells cannot be drilled within 500 ft. of building or water well, without the consent of the owner of the building or well).
[240] *Id*. DEP shall grant a variance from specified setback requirements if the restriction deprives the owner of the oil and gas rights of the right to produce or share in the oil or gas underlying the surface tract. Note, the statute also provides for a 300-foot setback from streams, springs, other bodies of water identified on a U.S. Geological Survey map, or wetlands, although these "shall" also be waived upon submission of a plan containing additional measures to protect waters. *Id*. § 3215(b).
[241] *Id*.
[242] South Franklin Township, Pa.; Ordinance No. 4-2008 (Wells may not be drilled within 200 feet from an existing habitable structure or existing water well without express written consent of the owner).
[243] Act 13 supersedes all local ordinances purporting to regulate oil and gas operations, other than those adopted pursuant to Pennsylvania municipalities and planning code and Flood Plain Management Act. However, implementation of this provision of the law has been enjoined pending resolution of a legal challenge brought by a number of local governments.
[244] Proposed 6 N.Y. Comp. Codes R. & Regs. 560.4(a)(1) (Well pad must be at least 500 ft. from a private water well unless waived by water well owner).
[245] *Id*. at 560.4(a)(2) (Well pads may not be located within 500 feet of the boundary of a primary aquifer). In addition, NY prohibits well pads within a primary aquifer, 100-year floodplain, and within 2,000 ft. of any public

Play/Basin	State-Distance from home	State-Distance from Private Water Well	State-Distance from source of drinking water	Local	Vertical fragmentation?
North San Juan (Colorado)	150 feet[247]	None	Buffer Zones to protect surface water intended for drinking water	450 from home without consent[248]	Yes
Upper Green River (Wyoming)	350 feet[249]	None	None	None	No

water supply well, reservoir, natural lake or man-made impoundment except those constructed for fresh water storage associated with hydraulic fracturing, and river or stream intakes. *Id.* at 560.4(a)(2)-(4).

[246] Our research did not identify any local laws directly regulating unconventional gas development in NY.

[247] COGCC R. 603(a). In high-density areas, wellheads must be at least 350 ft. from buildings. *Id*. at 603.e(2).

[248] Chapter 90 – La Plata County's Oil and Gas regulations, § 90-122: http://co.laplata.co.us/sites/default/files/departments/planning/chapter_90_adopted_12_7_2010.pdf ; Archuleta County Land Use Code Section 9.2.6.2: Archuleta County's Oil and Gas Development Permit Provisions (Amended Dec. 2010) http://www.archuletacounty.org/DocumentCenter/Home/View/295.

[249] Pits, wellheads, pumping units, tanks and treaters shall be located no closer than 350 ft. from designated public places. Supervisor may extend setbacks or grant exceptions for good cause. WY ADC Oil Gen. ch. 3, § 22(b).

Appendix D: Risk Factor Data

This appendix provides more detailed information on the six selected shale plays considered in this study. For each play, where data are available, we provide 1) an overview of the shale play geology and resource potential, 2) trend data on the number of wells being drilled, 3) information about water usage per well, 4) information on produced water volumes and wastewater management practices, 5) issues associated with freshwater acquisition, and 6) reported data on violations. In addition, this appendix provides more information about the severity index used for water violations (D.7).

Marcellus Shale Play, Pennsylvania

Overview

The Marcellus Shale formation extends across 600 miles within four states, covering an area of about 54,000 square miles. The thickness of the formation varies, but is typically thicker in the east (up to 250 feet) and thins toward the west (Sumi 2008). The Marcellus Shale is the middle Devonian layer between the upper Middle Devonian Mahantango and underlying Middle Devonian Onodaga Limestone formation (USGS 2011). Estimates of the total economically recoverable natural gas in the basin have changed significantly over the years—from an initial estimate of 1.9 trillion cubic feet (Tcf) in 2002 to 168–516 Tcf in 2008 (UM 2010). The U.S. Geological Survey recently estimated mean undiscovered resources for natural gas liquids of 3,379 million barrels and for natural gas of 84,198 billion cubic feet (USGS 2011).

Figure 63 shows the extent and approximate depth of the Macellus formation, which underlies New York, Pennsylvania, Maryland, West Virginia, and Ohio.

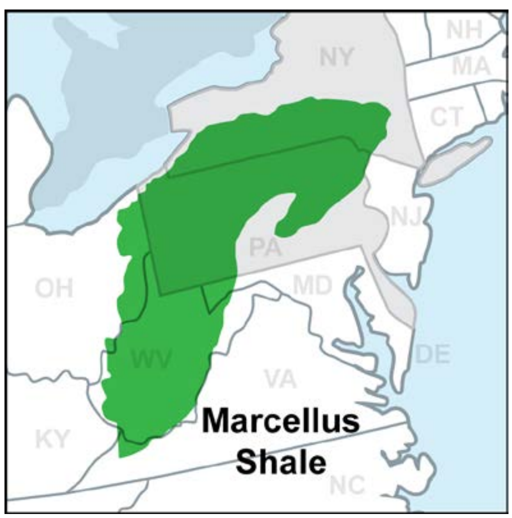


Figure 63. Extent of Marcellus Shale

Number of Wells

As of December 15, 2011, the Marcellus Shale Basin had 88 active operators. More than 9,600 permits have been submitted, with 9,328 issued. Only 36 permits have been denied since 2005 (PA DEP 2011a).The operators with the most permits in the Marcellus Shale include Chesapeake

Appalachia LLC with 1,614 drilling permits, Range Resources Appalachia LLC with 917 permits, and Talisman Energy USA Inc., with 896 permits (PA DEP 2012e).

However, the number of permits does not necessarily reflect the number of wells drilled. Only 44% of the permits resulted in a drilled well (PA DEP 2011b). Figure 64 shows the total number of permits vs. wells drilled in 2010. Figure 65 shows the total number of wells drilled in 2011.

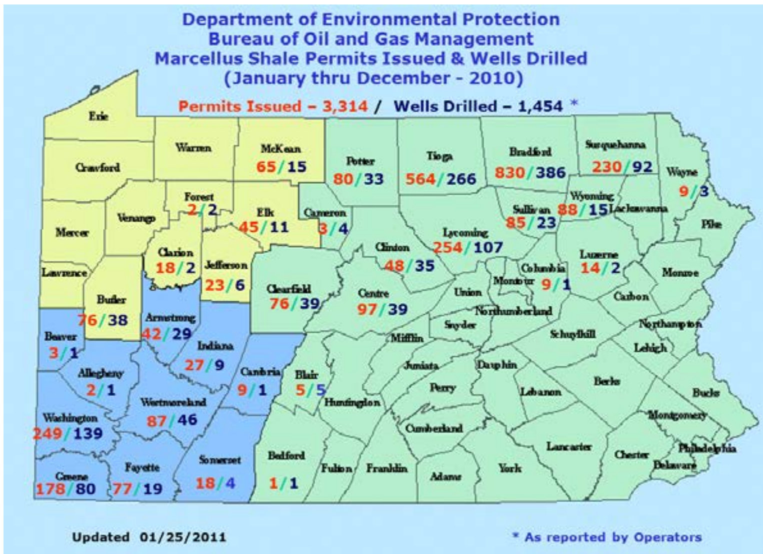


Figure 64. Marcellus Shale permits issued vs. number of wells drilled (PA DEP 2011b)

Water Usage per Well

Some 102 wells in the Marcellus Shale of Pennsylvania were randomly selected for an analysis of water usage per well. The total volume of water per well was acquired through fracfocus.org, and all other information (e.g., latitude, longitude, spud date) was gathered from the fractracker.com data set, "All Wells Marcellus," a compilation of data from the Pennsylvania Department of Environmental Protection (DEP). API numbers and well location files were cross checked between the fractracker and fracfocus data sets. Reporting to fracfocus is voluntary, causing some data to not match official API numbers and latitude/longitude found in regulated DEP data. If discrepancies occurred, then fracfocus data were discarded and a new well was chosen. Table 31 shows results for the 102 wells in Pennsylvania.

Table 31. Analysis of Water Usage per Well (gallons) for 102 Marcellus Wells (fracfocus.org)

Mean	**Max**	**Min**	**Range**	**Standard Deviation**
4,842,070	9,548,784	430,584	9,118,200	1,690,457
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
4,567,320	5,802,941	3,912,996	1,889,945	0.4422

As seen in Table 31, the average volume per well was about 4,842,000 gallons. It is important to note the large range of values—with a minimum of 430,584 gallons and a maximum of 9,548,784 gallons. A histogram (Figure 66) displaying the total volume of water was created by evenly distributing the range of values into twenty bins and then counting the total number of wells for each bin.

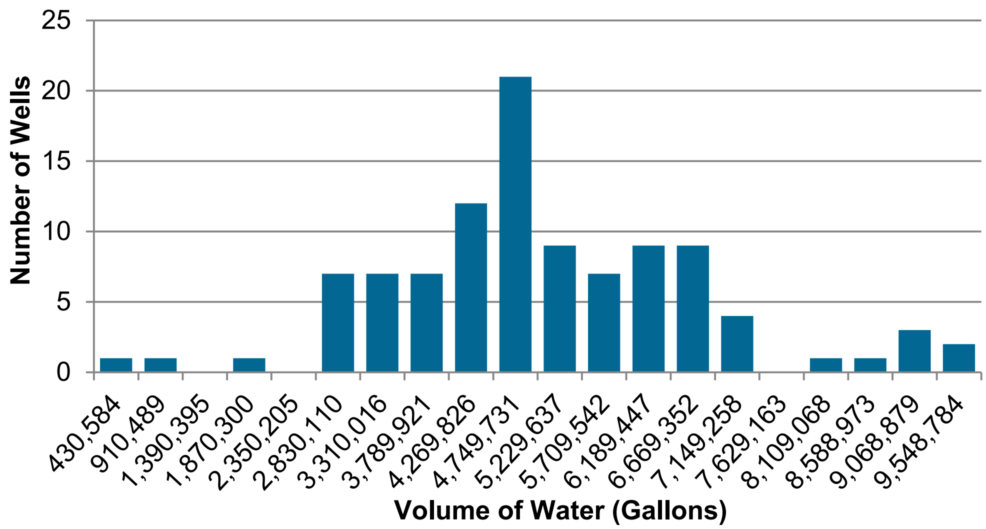


Figure 66. Histogram for 100 wells of total volumes (gallons) (fracfocus.org)

Table 32. Average Water Volume per Well by Well Type (gallons) (fracfocus.org)

Well Type	Vertical	Horizontal
Average	5,431,035	4,756,042
Sample Size	13	89

The effect of a small sample size can be seen in the comparison of average water used by type in vertical and horizontal wells in Table 32. In general, horizontal wells use much more water than vertical wells—a vertical well typically uses 0.5 to 1 million gallons of water, whereas a horizontal well uses between 4 to 8 million gallons of water (Natural Gas 2010). Further data collection is needed to provide a better comparison of vertical and horizontal wells.

Produced Water

The DEP has official production and waste reporting data on its Oil and Gas Reporting website (PA DEP 2012b). The website contains statewide data that can be downloaded on production and waste on a yearly basis. Each waste data set contains the total waste for each well per year, with the waste described by quantity, waste type, and disposal method. Before 2010, waste reports were not well organized, and an online reporting system had not yet been created, causing many wells to be excluded from the data sets. Furthermore, a server malfunction caused the loss of any relevant 2007 data. Since 2010, all waste produced by all wells in Pennsylvania have been accurately reported. However, reporting period dates have changed to biannual, rather than annual.

Brine production and fracking fluid flowback were analyzed. Although the DEP does not have an official definition of flowback and brine, flowback can be considered the water produced before the well is put into production on a gas line.

For our analysis, natural gas wells in the Marcellus Basin were filtered out from DEP data. We observed that portions of a well's waste were reported multiple times if the waste was taken to more than one treatment facility. The duplicate data were removed from the analysis.

Brine and fracking fluid wastes were divided and analyzed separately. The results can be seen in Tables 33 and 34, along with Figures 67 and 68, with all units in gallons.

Table 33. Summary of Brine Produced (thousands of gallons) (PA DEP 2012b)

				Disposal Method						
Year	**Total Wells**	**Total Volume**	**Average Volume Per Well**	**Brine/ Industrial Water Treatment Plant**	**Injection Disposal Well**	**Municipal Sewage Treatment Plant**	**Other**	**Reuse Other Than Road Spreading**	**Road Spreading**	**Landfill**
2006	14	160.4	14.2	124.9	0	30.6	0	0	4.8	0
2008	204	50,211.0	246.1	1,345.1	775.9	40,067.1	3,457.8	4,501.9	63.0	0
2009	445	231,316.3	519.7	169,860.5	4,707.5	36,402.4	16,466.8	3,875.8	3.1	0
July 2010-June 2011	1,614	287,088.1	177.8	123,623.9	35,541.3	2,711.6	19,931.4	105,248.4	7.8	23.3

Table 34. Summary of Fracking Fluid Produced (thousands of gallons) (PA DEP 2012b)

				Disposal Method						
Year	**Total Wells**	**Total Volume**	**Average Volume Per Well**	**Brine/ Industrial Water Treatment Plant**	**Injection Disposal Well**	**Municipal Sewage Treatment Plant**	**Other**	**Reuse Other Than Road Spreading**	**Road Spreading**	**Landfill**
2006	2	255.4	127.7	255.4	0	0	0	0	0	0
2008	106	46,881.9	442.3	8,792.4	0	25,238.7	11,717.3	1,133.3	0	0
2009	225	105,869.6	470.5	24,505.2	610.2	46,570.4	26,371.2	7,812.4	0	0
July 2010-June2011	1,128	249,336.3	221.0	110,377.0	945.1	284.9	646.1	137,009.5	138.1	73.4

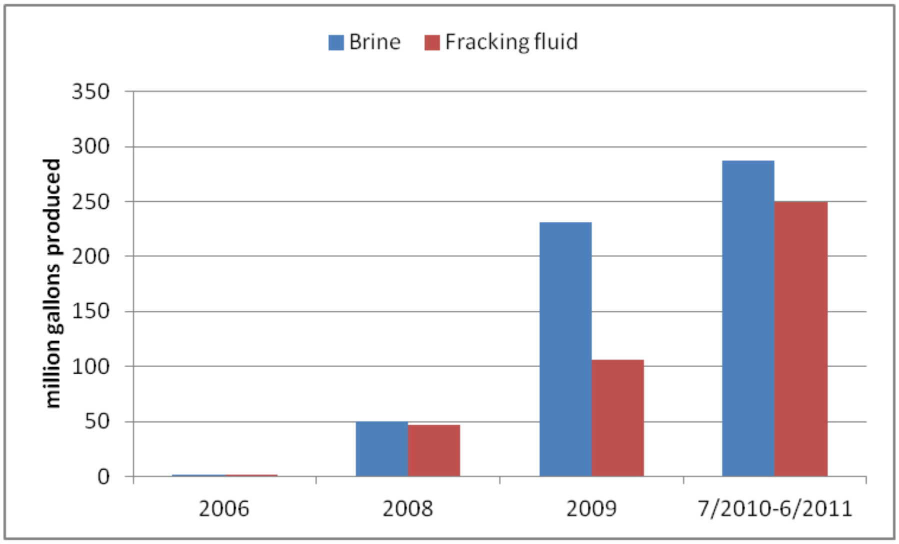


Figure 67. Total volume of produced water, 2006–2011 (PA DEP 2012b)

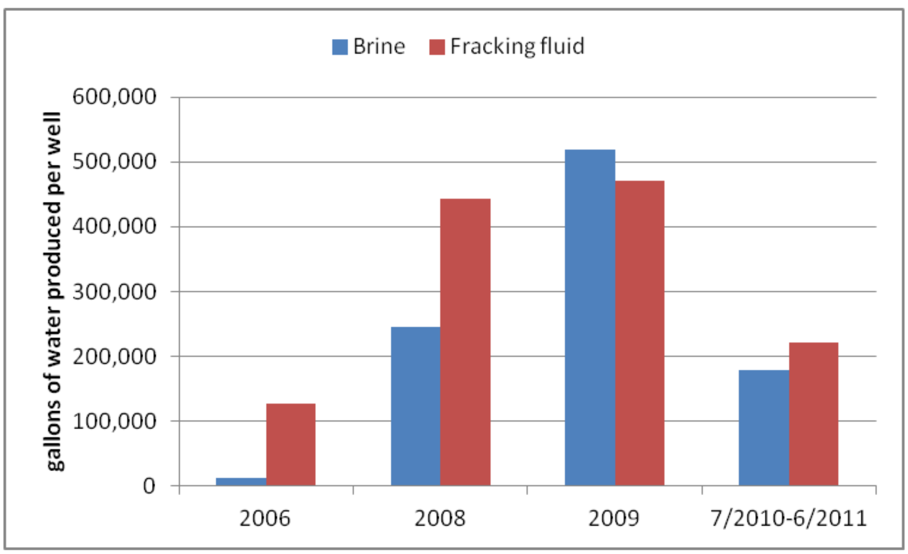


Figure 68. Average volume of produced water per well, 2006–2011 (PA DEP 2012b)

Based on Figure 67, the quantity of both produced brine and fracking fluid are clearly increasing each year—due to the increasing number of wells drilled each year. The final reporting period (July 2010–June 2011) had 1,614 wells producing brine, which is 1,169 more wells than the 2009 period (PA DEP 2012b). As seen in Figure 68, the increase in total brine and fracking fluid does not correlate with average produced brine and fracking fluid per well. There is no recognizable trend in produced water per well, as 2009 had a higher average than any other year.

Water Acquisition

Water withdrawal permit information for the Marcellus in this study focused on the Susquehanna River Basin (SRB). The Marcellus formation underlies 72% of the SRB, covering most of Pennsylvania and part of New York (Arthur 2010). The Susquehanna River Basin Commission

(SRBC) has been the forerunner in determining water usage regulations, monitoring, and permits. The SRBC actively regulates water withdrawal by oil and gas operators; all water withdrawal outside of the SRB is regulated by the DEP.

SRBC issues a report on all approved water sources for natural gas development in the SRB (SRBC 2012a). These permits include the fresh-water source, as well as the maximum allowed uptake per day. These uptakes are rarely at capacity and, according to the SRBC, many sources are used for redundancy due to passby flow conditions when water levels are low (SRBC, 2012a). It is possible to source where operators obtain their water. For example, SWEPI, LP has three different public water suppliers in three different counties. Public water supply does not have a maximum allowed daily uptake, whereas all other supplies do. SWEPI only has one docket approval for a fresh-water source—the Allegheny River in Warren County. This permit allows up to 3 million gallons per day (mgd) of water to be used. SWEPI sources the rest of its water from other drilling companies who share their water permits. Overall, SWEPI has eight different water sources, ranging from 0.217 to 3 mgd. Additional information is available regarding percentage of ground-water to surface-water permits and amounts of water used (SRBC 2011a).

Cost of Acquisition

Fees are associated with fresh-water withdrawal permits. The schedule includes a breakdown of a tiered fee system based on withdrawal amount, as well as consumptive vs. non-consumptive use (SRBC 2011a). Consumptive use is defined in 18 CFR § 806.3 as, "The loss of water transferred through a manmade conveyance system or any integral part thereof… injection of water or wastewater into a subsurface formation from which it would not reasonably be available for future use in the basin, diversion from the basin, or any other process by which the water is not returned to the waters of the basin undiminished in quantity (e-CFR 2012)."

On a per gallon basis, the SRBC fees range from \$0.00685–0.1425/gallon for consumptive use, and \$0.0030–0.07475/gallon for non-consumptive withdrawals (SRBC 2011a).

Considering SWEPI, LP, it can be seen that a typical docket of 0.250 mgd of surface water would cost \$9,975 if the water was not used consumptively. If the use is consumptive, then \$1,000 is added as an annual compliance and monitoring fee. There will also be a consumptive-use mitigation fee if the company wishes to use the fee as a method of compliance with 18 CFR §806.22(b). This section states that during low flow periods, several steps may be taken to mitigate consumptive use. One option is to reduce water withdrawal from a source equal to the consumptive use of the operator. Another option is to take water from another approved source. If these or the other provided options are not chosen, the company may choose to pay a fee of \$0.29 per 1,000 gallons of water consumed. In the case of SWEPI, this may be an additional cost of \$72.50. Companies pay for metering systems and report to the SRBC on a daily basis for each well on its water use.

Another source of fresh water is public supply. The cost of this source varies from utility to utility, but most rates can be found on utility websites. Rates vary significantly from supplier to supplier, and oftentimes unique deals are made between supplier and operator. The deal between East Resources Management, LLC and Morningside Heights Water District approves up to 400,000 gallons per day at a rate of \$0.0145 per gallon (Pressconnects 2010). This is 60% greater than water supplier P.A. American Water, which charges $0.008979 per gallon (American Water 2012).

The above costs refer to obtaining water and do not cover the price of transporting the water. Most water is transported by either pumping or trucking. PSU estimates average trucking costs of $0.2 per gallon (Pressconnects 2010). Further analysis of water-supply distances to wells would need to be studied using GIS to assess the actual cost of water transportation.

Violations

The majority of the violations reported from 2009–2011 fall under the category of "minor - no effect" (Figure 69 and Table 35) (NEPA 2012). "Procedural" violations account for about 20%, and "minor effect" and "substantial" account for about 10%. Also, it should be noted that there are no "major" violations. This data set includes all of the violations from 2009–2011 (NEPA 2012). Further information on violations can be found in D.7 of this appendix.

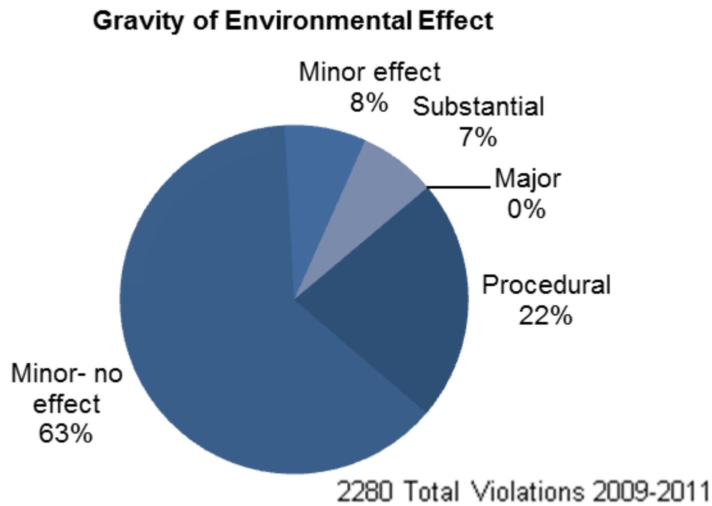


Figure 69. Pennsylvania violations (NEPA 2012)

Table 35. Pennsylvania Violations (NEPA 2012)

Procedural	510	22.4%
Minor - no effect	1433	62.9%
Minor effect	173	7.6%
Substantial	164	7.2%
Major	0	0.0%
Total	2280	

Barnett Shale Play, Texas

Overview

In the early 1900s, geological mapping noted a thick, black, organic-rich shale in an outcrop near the Barnett stream (TRRC 2012e). The Barnett Shale formation exists under extensive areas in Texas and crops out on the flanks of the Llano Uplift, 150 miles to the south of the core area (Figure 70). Current boundaries of the formation are due primarily to erosion (TDWB 2007). The Fort Worth Basin is bounded by tectonic features to the east—notably, the Ouachita Overthrust, an eroded, buried mountain range—and to the north by the uplifted Muenster and Red River Arches. The Barnett Shale dips gently toward the core area and the Muenster Arch from the south where it crops out and thins considerably to the west; its base reaches a maximum depth of ~8,500 ft (subsea) in the northeast. The depth to the top of the Barnett ranges from ~4,500 ft in northwestern Jack County, to ~2,500 ft in southwest Palo Pinto County, to ~3,500 ft in northern Hamilton County, to ~6,000 ft in western McLennan County, to ~7,000 to 8,000 ft in the Dallas-Fort Worth area. Further west in Throckmorton, Shackelford, and Callahan Counties, the depth to the Barnett ranges between ~4,000 and 2,000 ft (TDWB 2007).

The U.S. Geological Survey (USGS) estimated the mean gas resources at 26.7 Tcf (USGS 2004).

Figure 70. Extent of Barnett Shale

Figure 70 shows the extent of the Barnett Shale in Texas. The formation is actually considered to be a hydrocarbon source, reservoir, and trap, all at the same time. As a reservoir, it is known as a "tight" gas reservoir, indicating that the gas is not easily extracted. However, hydraulic fracturing technology has made it possible to extract the gas (TRRC, 2012d). For the Barnett Shale, permeability ranges from microdarcies to nanodarcies, porosity ranges from 0.5% to 6%, and water saturation is below 50%.

Future development will be hampered, in part, because major portions of the field are in urban areas, including the rapidly growing Dallas-Fort Worth Metroplex. Some local governments are researching means by which they can drill on existing public land (e.g., parks) without disrupting other activities so they may obtain royalties on any minerals found. Others are seeking compensation from drilling companies for roads damaged by overweight vehicles, because many of the roads are rural and not designed for use by heavy equipment. In addition, drilling and exploration have generated significant controversy (TRRC, 2012d).

Number of Wells

The Barnett Shale has experienced substantial development over the last decade, as evidenced by the number of wells (Figure 71) and estimates of total gas production (Figure 72).

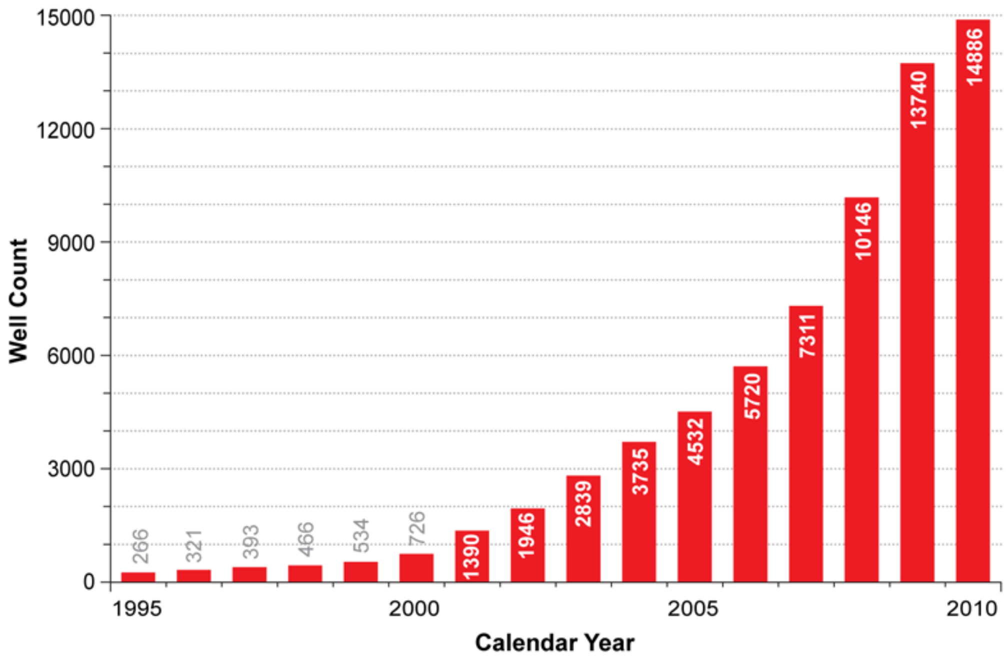


Figure 71. Wells in Barnett Shale, 1995-2010 (TRRC, 2012c)

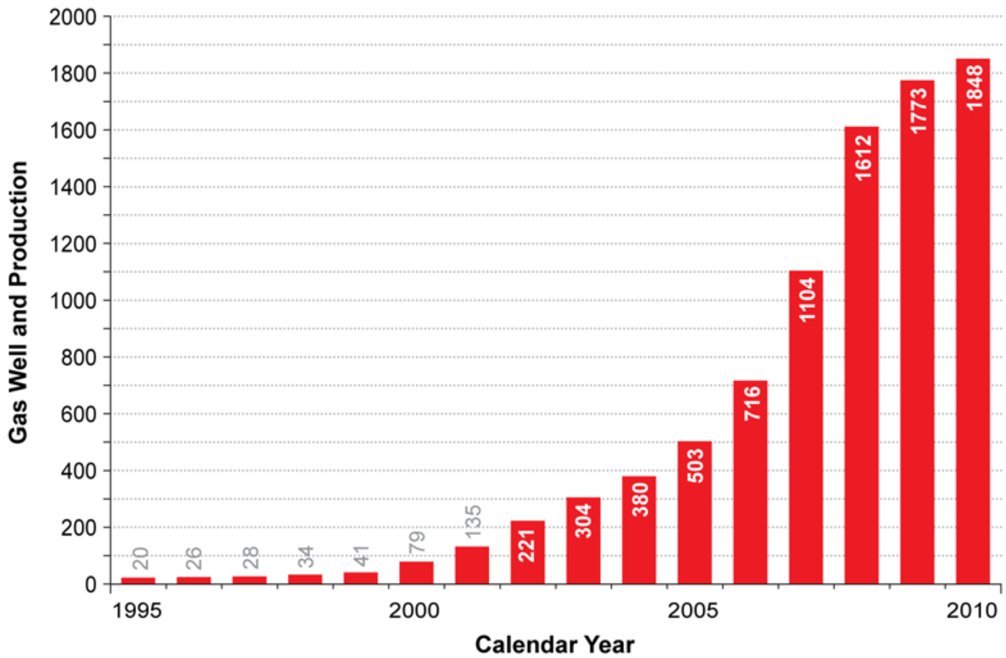


Figure 72. Gas production in the Barnett Shale (bcf), 1995-2010 (TRRC, 2012e)

Water Usage per Well

Table 36 shows the analysis results on 100 Barnett Shale wells selected randomly from fracfocus.org.

Table 36. Statistics of Water Use (Gallons) (fracfocus.org)

Mean	**Max**	**Min**	**Range**	**Standard Deviation**
2,537,853.848	26,315,125	29,186	26,285,939	3,512,472.559
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
1,293,306	4,298,286	86,751	4,211,535	3.500964058

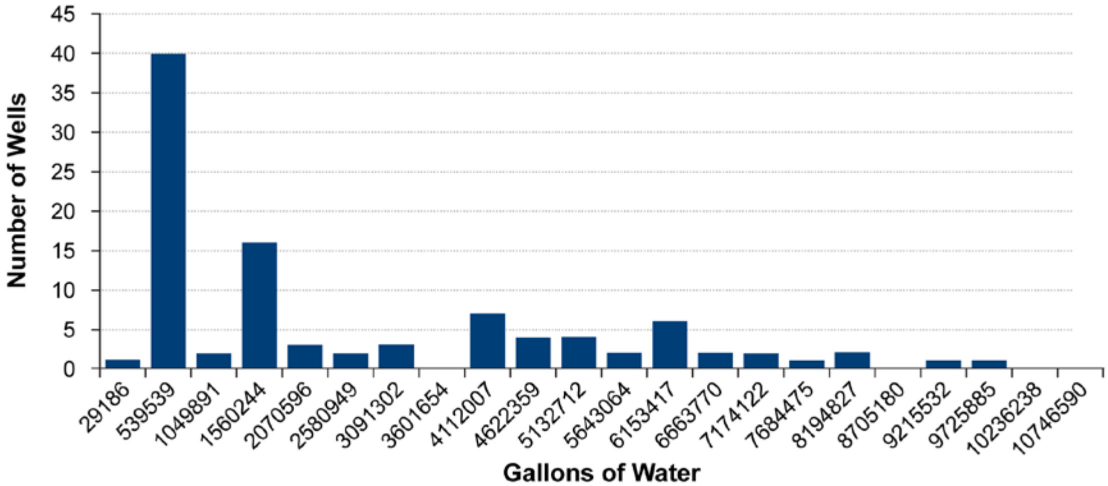


Figure 73. Histogram of 100 wells for total water volume (gallons) (fracfocus.org)

As seen in Table 36, the average volume per well was 2,537,853 gallons, with values ranging from 29,186 gallons to 26,315,125 gallons (fracfocus.org). Figure 73 is a histogram displaying the total volume of water, created by evenly distributing the range of values into twenty bins and then counting the total number of wells for each bin.

Produced Water

No produced water data are available for Barnett shale. However, the Railroad Commission (RRC) of Texas requires every operator to report—into a query system—how much water is disposed. The current method used for disposal in the Barnett Shale is deep-well injected. The Injection Volume Query from the RRC database was used and monthly county-wide or operator-wide injected volumes can be obtained (TRRC 2011).

Violations

Figure 74 expresses the violations from 2009–2011 in Texas according to the severity of environmental effect (Wiseman 2012). Of the 35 total violations (Table 37), 35% of the violations are “minor - no effect” and “substantial.” “Procedural” account for about 20%, and “major” and “minor effect” account for 3%. It should be noted that these violations only include wells for which formal compliance or administrative orders were issued. Therefore, these data are not comprehensive and do not represent the total number of violations. Further information on violations can be found in D.7 of this appendix.

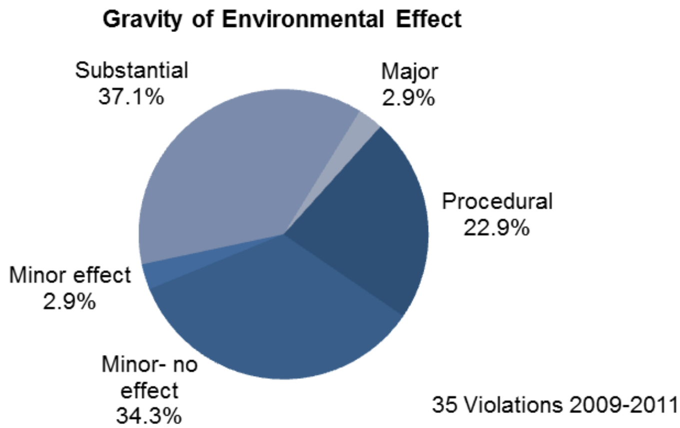


Figure 74. Texas violations (Wiseman 2012)

Table 37. Texas Violations (Wiseman 2012)

Texas		
Procedural	8	22.9%
Minor - no effect	12	34.3%
Minor effect	1	2.9%
Substantial	13	37.1%
Major	1	2.9%
Total	35	

Eagle Ford Shale Play, Texas

Overview

The Eagle Ford Shale play extends across 23 counties, covering an area of 20,000 square miles (Figure 75). The Eagle Ford Shale has an average thickness of 250 feet and contains an estimated 21 Tcf of shale gas and 3 billion barrels of shale oil (EIA 2011).

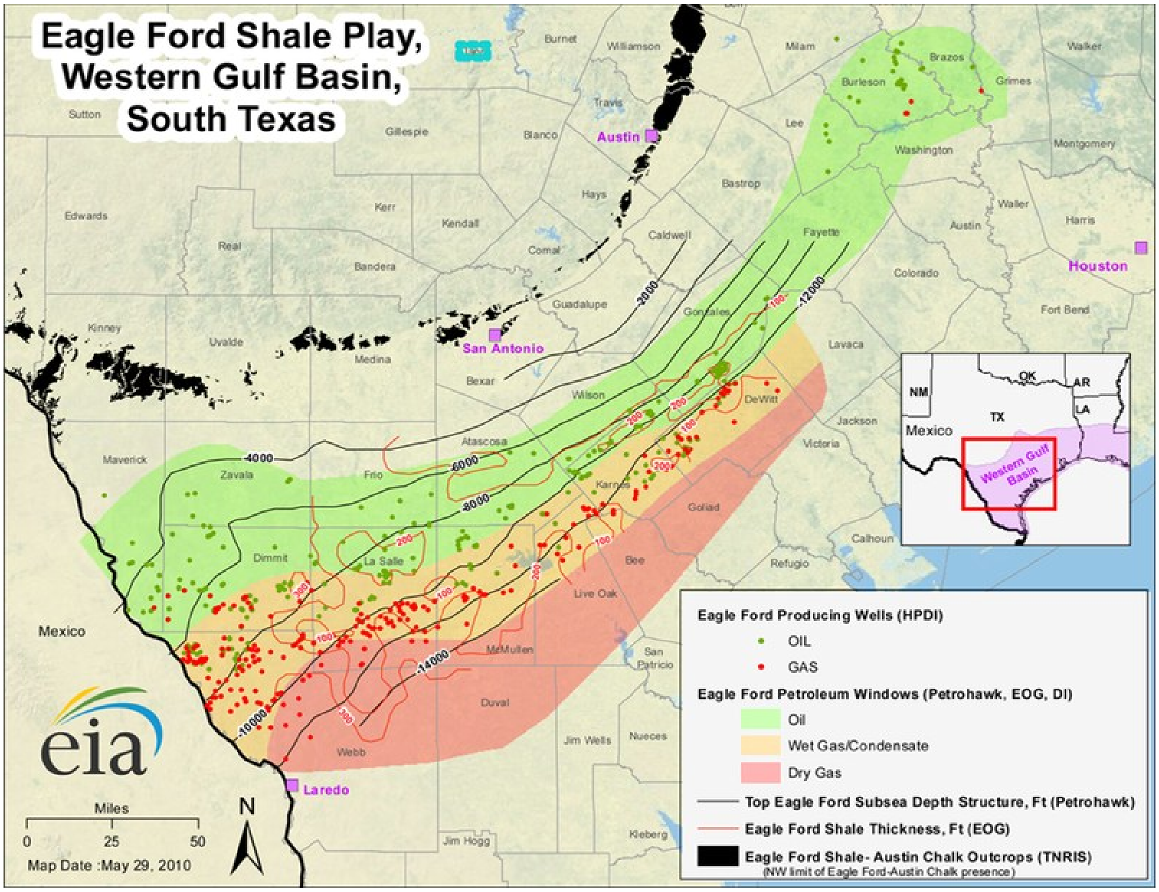


Figure 75. Extent of Eagle Ford Shale play (Eagle Ford Shale 2012)

Number of Wells

In 2008, Petrohawk drilled the first well in the Eagle Ford Shale, and since then, gas production has more than doubled—from 108 bcf in 2010 to 287 bcf in 2011. Oil production increased from more than 4 million barrels in 2010 to more than 36 million barrels in 2011 (TRRC 2012a). Increased production reflects the increases in drilling permits issued and in the number of oil and gas wells. Figure 76 shows the total number of producing oil and gas wells over the past three years.

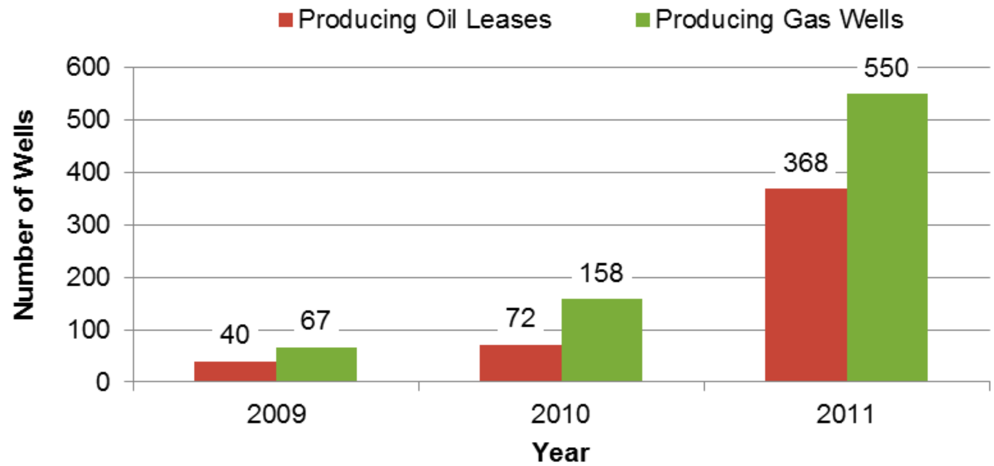


Figure 76. Number of producing oil and gas wells in Eagle Ford (Eagle Ford Shale 2012)

With 2,826 issued drilling permits in 2011 alone, the well count in Eagle Ford may steadily increase (Eagle Ford Shale 2012).

Water Usage per Well

Wells in the Eagle Ford Shale were randomly selected from fracfocus.org. Figure 77 shows a histogram of the water used per well, and Table 38 shows the average, maximum, and minimum water used per well.

Table 38. Fresh Water Use in Eagle Ford (in gallons) (fracfocus.org)

Mean	Max	Min	Range	Standard Deviation
3,751,751	7,084,098	77,658	7,006,440	1,276,506
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
3,608,905	4,386,965	3,116,039	1,270,927	-0.079

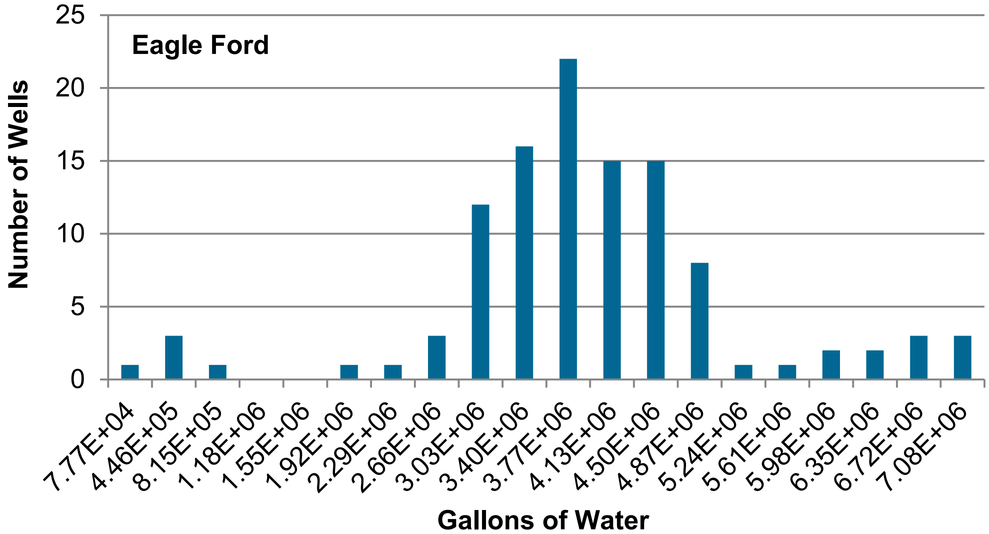


Figure 77. Fresh-water use in Eagle Ford per well (fracfocus.org)

The Texas Commission of Environmental Quality monitors surface water use in Texas. Surface water rights are issued to operators, and withdrawal amounts can be found on the TCEQ website (http://www.tceq.texas.gov/). However, withdrawal information is based on water-right number and is not shown on a well-to-well basis (TCEQ 2012).

Haynesville Shale Play, Louisiana

Overview

The Haynesville Shale extends over large sections of southwestern Arkansas, northwest Louisiana, and East Texas (Figure 19). It is up to 10,500 to 13,000 feet below the surface, with an average thickness of about 200–300 feet, and overs an area of about 9,000 square miles (TRRC 2012f).

Haynesville Shale is an important shale gas play in East Texas and Louisiana. Estimated recoverable reserves are as much as 60 Tcf, with each well producing 6.5 bcf on average (Hammes 2009). The formation came into prominence in 2008 as a potentially major shale gas resource, and production has boomed since late March 2008 (TRRC 2011). Producing natural gas from the Haynesville Shale requires drilling wells from 10,000 to 13,000 feet deep, with the formation being deeper nearer the Gulf of Mexico. The Haynesville Shale has recently been estimated to be the largest natural gas field in the contiguous 48 states, with an estimated 250 Tcf of recoverable gas (Nossiter 2008).

Figure 78. Extent of Haynesville Shale

The Haynesville Shale is lithologically heterogeneous, but is often an organic-rich mudstone. The composition varies greatly according to the geographic location and stratigraphic position of the mudstones—from calcareous mudstone near the ancient carbonate platforms and islands, to argillaceous mudstone in areas where submarine fans prograded into the basin and diluted organic matter. The Haynesville formation was deposited about 150 million years ago in a shallow offshore environment (Geology.com, 2012b).

Number of Wells

The State of Louisiana, Department of Natural Resources, provides information on monthly well counts. Well counts (Figure 79) have varied from 2009–2011 as old wells are abandoned and new wells are drilled and leased. However, total gas production (Figure 80) has increased from 2009–2011.

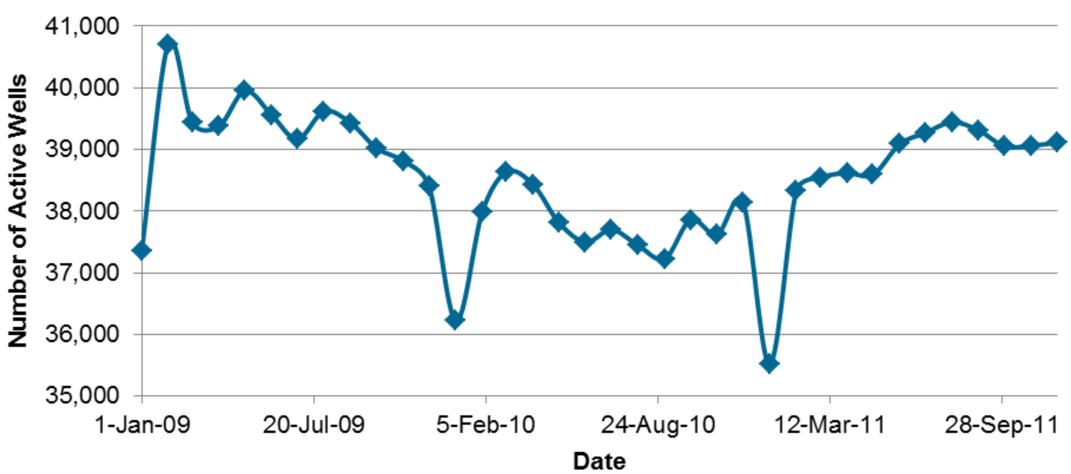


Figure 79. Monthly well count (2006–2011) (LADNR 2012b)

The total number of wells shows a significant drop at the end of 2010, after some natural fractures were seen in the formation cores extracted during test drilling. These fractures suggest the risk of anthropogenic faulting of the surrounding land; however, drilling continued after these problems were resolved.

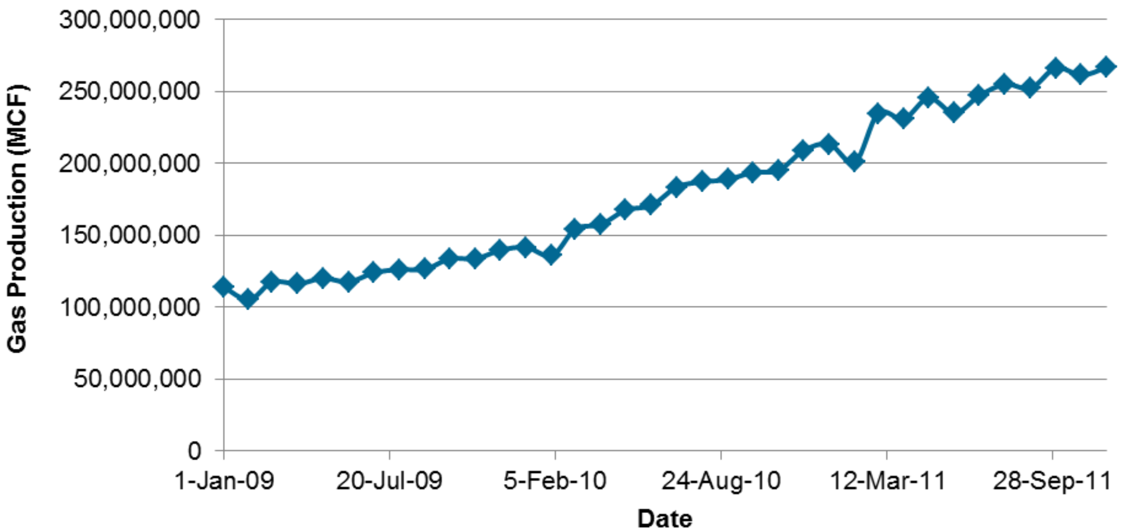


Figure 80. Monthly gas production (2009–2011) (EIA 2011)

Production is increasing almost linearly, despite a drop in well count. At the end of 2011, production was twice that in 2009.

Water Usage per Well

One hundred wells in the Haynesville Shale were randomly selected. Table 39 gives statistics on water usage, and Figure 81 is a histogram of the distribution of water usage distributed evenly into twenty bins.

Table 39. Analysis of Water Usage for 100 Haynesville Shale Wells (fracfocus.org)

Mean	Max	Min	Range	Standard Deviation
4,568,683	9,567,936	8,736	9,559,200	2,243,797
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
4,925,256	6,255,663	3,875,203	2,380,460	-0.578

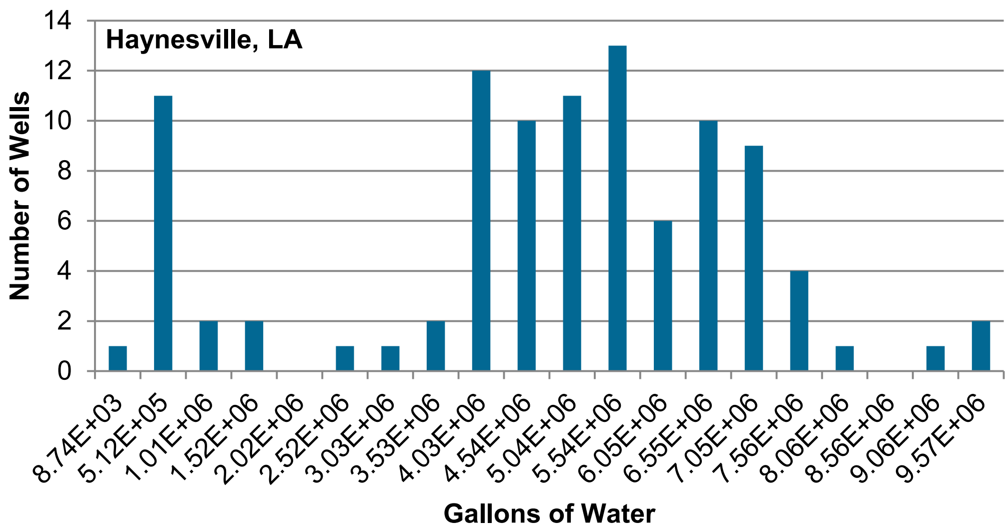


Figure 81. Fresh-water use for 100-well sample (fracfocus.org)

Violations

Figure 82 expresses the violations from 2008–2011 in Louisiana according to the severity of environmental effect. A majority of the violations are in the "procedural" category (Table 40). "Minor - no effect" violations make up about 30%, and "minor effect," "substantial," and "major" account for less than 10% (Wiseman 2012). These data include mostly Haynesville wells with compliance orders from January 1, 2008 through July 14, 2011. About 83 additional well incidents had insufficient information to be categorized. Further information on violations can be found in D.7 of this appendix.

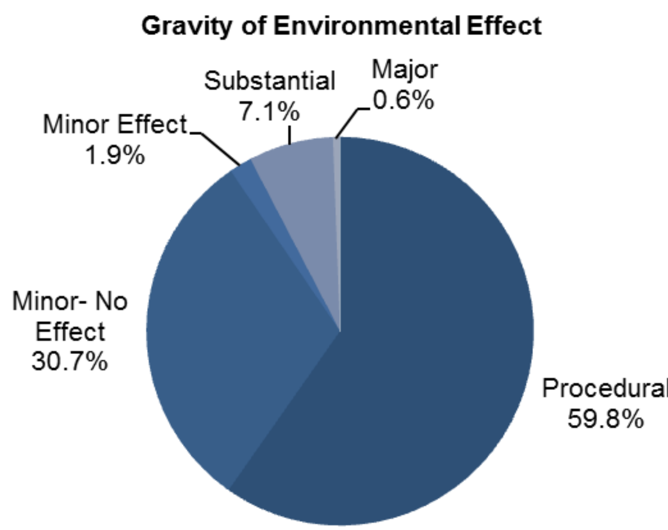


Figure 82. Louisiana violations (Wiseman 2012)

Table 40. Louisiana Violations (Wiseman 2012)

Procedural	95	59.8%
Minor - no effect	49	30.7%
Minor effect	3	1.9%
Substantial	11	7.1%
Major	1	0.6%
Total	158	

Upper San Juan Basin, Colorado, New Mexico

Overview

The San Juan Basin covers an area of about 7,500 square miles across the Colorado and New Mexico border in the Four Corners region (Figure 83). It spans about 100 miles north-south in length and 90 miles east-west in width. In the San Juan Basin, the total thickness of all coalbeds ranges from 20 to more than 80 feet. Coalbed methane production occurs primarily in coals of the Fruitland Formation, but some coalbed methane is trapped within the underlying and adjacent Pictured Cliffs Sandstone; many wells are present in both zones (EPA 2004).

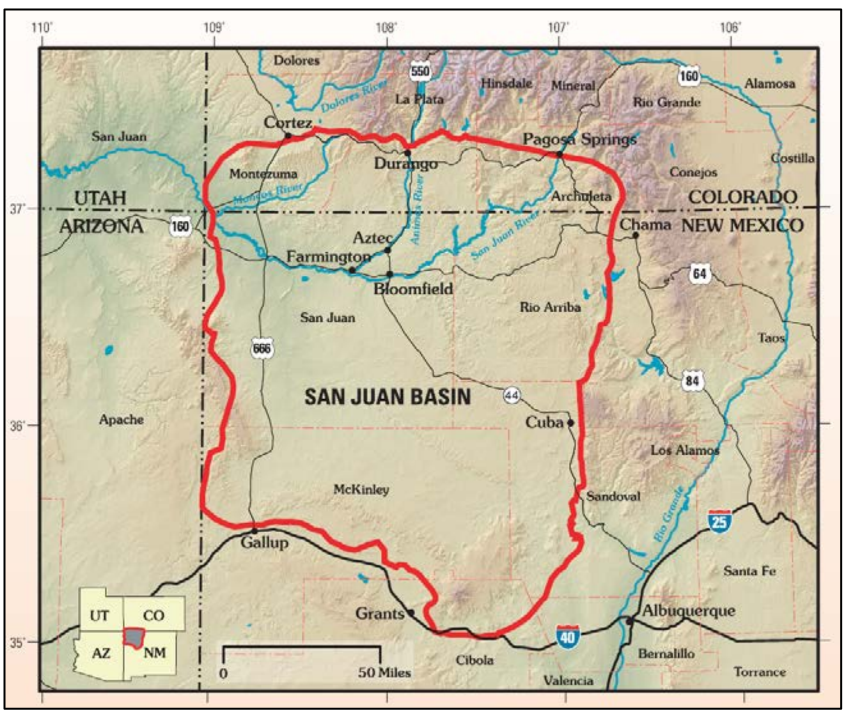


Figure 83. Extent of the San Juan Basin (USGS 2002a)

The Fruitland Formation is the primary coal-bearing unit of the San Juan Basin, as well as the target of most coalbed methane production. The Fruitland coals are thick and have individual beds up to 80 feet thick. The formation is composed of interbedded sandstone, siltstone, shale, and coal. Some of the most important natural-gas-producing formations include the Fruitland, Pictured Cliffs, Mesaverde, Dakota, and Paradox formations and are located in La Plata County. Early development of natural gas began here in the 1920s. In La Plata County, coalbed methane production began in the late 1970s. Traditional natural gas reserves have been—and continue to be—developed at a steady pace (USGS 2002a).

Two types of natural gas wells exist within La Plata County: conventional and coalbed. Conventional gas wells are usually deeper—3,500 to 10,000 feet—and extract gas and oil from sandstone formations such as the Mesaverde and Dakota (La Plata Energy Council 2012). The shallower coalbed gas wells generally range from 1,000 to 4,000 feet deep and extract gas from coal-bearing formations (EPA 2004). The Fruitland formation is La Plata County's methane-rich coalbed formation.

Produced Water

Conventional wells initially produce large volumes of gas and very little water. Over time, gas production declines and water increases. Coalbed wells are just the opposite, producing large quantities of water and low gas quantities at the beginning; later, water production declines and gas production increases. Table 41 shows oil, gas, and water production from 2007–2011.

Table 41. Oil, Gas, and Water Production in La Plata County (COGCC 2012a)

Year	Oil Production (bbl)	Gas Production (Mcf)	Water Production (bbl)
2007	35,883	412,488,324	24,032,308
2008	38,038	425,541,599	20,154,062
2009	33,975	425,439,680	24,177,214
2010	33,396	422,450,451	31,942,703
2011	26,747	373,116,167	21,231,213

Based on the database provided by the Colorado Oil and Gas Conservation Commission (COGCC), five methods are used to dispose of water in La Plata County: disposal in a central pit well, injection on lease, disposal at a commercial disposal facility, evaporation in an onsite pit, and through surface discharge (COGCC 2012a). Table 42 and Figure 84 show disposal methods in La Plata County from 2007 to 2011.

Table 42. Produced Water and Disposal Method in La Plata County (Million Gallons) (COGCC 2012a)

Disposal Method	2011	2010	2009	2008	2007	Average
Central Disposal Pit Well	637	1,213	726	646	736	791
Injected on Lease	350	362	175	201	179	253
Commercial Disposal Facility	47	60	61	53	37	52
Onsite Pit	2	2	1	2	1	1
Surface Discharge	NON	NON	NON	NON	NON	
SUM	1,036	1,638	963	901	953	1,098
Percentage	60%	61%	51%	48%	57%	55%
Estimation	1,725	2,697	1,876	1,872	1,674	1,969

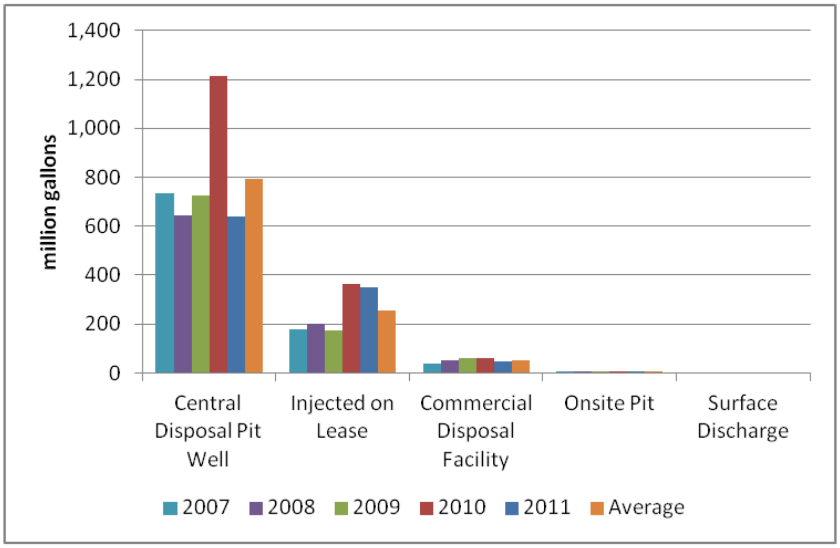


Figure 84. Water disposal volumes and methods in La Plata County (million gallons) (COGCC 2012a)

There is no surface discharge in La Plata County and minimal use of onsite pits. The most widely used method of disposal in La Plata County is a central disposal pit well. Some 70% of produced water is disposed in a central disposal pit well, 23% of produced water is injected on the lease, and 4.7% goes to a commercial disposal facility. Trends in the state of Colorado (Table 43) differ from those in La Plata County (Table 42).

Table 43. Produced Water and Disposal Method in the State of Colorado (Million Gallons) (COGCC 2012a)

Disposal Method	2011	2010	2009	2008	2007	Average
Central Disposal Pit Well	4,609	3,314	3,237	3,135	3,678	3,595
Injected on Lease	8,095	11,243	6,715	7,194	11,666	8,983
Commercial Disposal Facility	1,248	2,266	1,665	1,303	962	1,489
Onsite Pit	3,001	2,962	3,213	5,128	3,588	3,579
Surface Discharge	2,191	1,218	1,219	283	677	1,117
Sum	19,144	21,003	16,049	17,042	20,572	18,762

Violations

For the state of Colorado, the only publicly accessible statistics related to violations are Notices of Alleged Violations (NOAVs). The number of NOAVs does not represent the number of violations because violations do not necessarily lead to the issuance of NOAVs. Additionally, when NOAVs are issued, they may cite violations of more than one rule, order, or permit condition. Colorado violations could not be acquired.

Green River Basin, Wyoming

Overview

The Green River Basin Oil Shale Field, as seen in Figure 85, is located in Wyoming, Utah, and Colorado, on the western flank of the Rocky Mountains. The main part of the Green River Basin Formation is located in the southwest portion of Wyoming. The Colorado oil shale is expected to hold the largest amount of oil from shale. Specifically, the Piceance Creek Basin is the large producer for oil shale in the Green River Formation (Oil Shale Gas 2012).

The estimates of the oil resource within the Green River Formation range from 1.3 to 2.0 trillion barrels. Because not all resources are recoverable, a moderate estimate of recoverable oil is about 800 billion barrels (Oil Shale Gas 2012).

Figure 85. Extent of Green River Formation

The Jonah Field is located in the northern part of the Green River Basin and has produced more than 1.0 Tcf of gas since production commenced in 1992 (Oil Shale Gas 2012). Development of this field resulted from applying advanced fracture stimulation techniques. The field has undergone several iterations of development, with some sections of the field currently being developed on 10-acre well spacing; the current well spacing is around 20 acres. The field produces from a series of stacked reservoirs within the Cretaceous Mesaverde and Lance Formations. The field is bounded between two faults forming a wedge-shaped field.

Water usage per well

One hundred wells in the Green River Formation were randomly selected. Table 44 gives statistics about water usage, and Figure 86 is a histogram of water usage distributed evenly into twenty bins.

Table 44. Analysis of Water Usage for 100 Green River Formation Wells (fracfocus.org)

Mean	Max	Min	Range	Standard Deviation
1,076,417	4,451,034	14,467	4,436,567	1,230,306
Median	**Upper Quartile**	**Lower Quartile**	**Interquartile Range**	**Skewness**
367,522	1,665,741	201,280	1,464,461	1.40

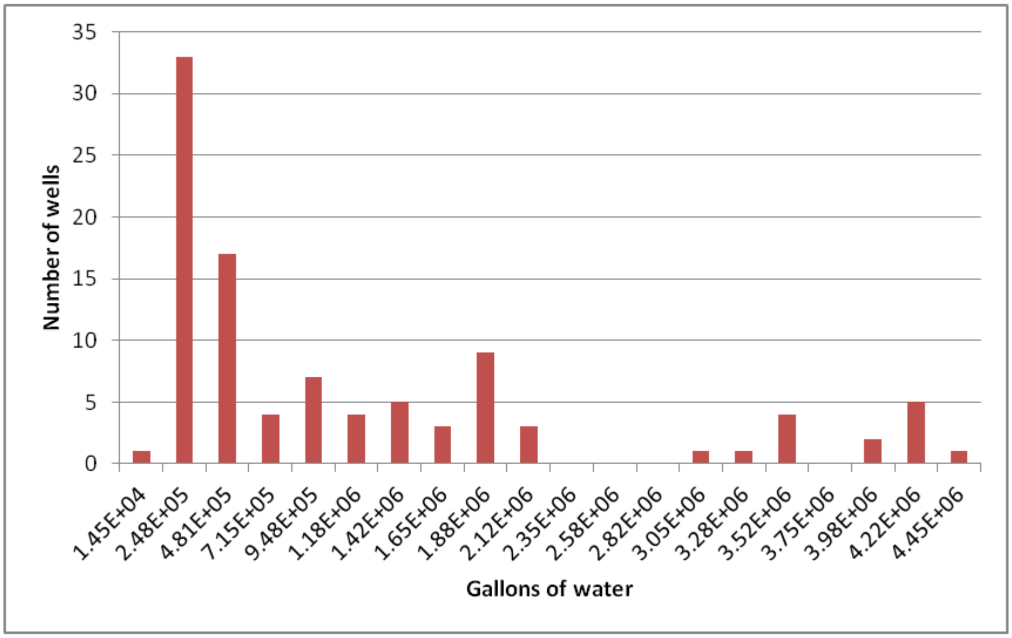


Figure 86. Fresh-water use for 100-well sample (fracfocus.org)

Figure 87 shows the volumes of hydraulic fracturing fluids used in Wyoming by county.

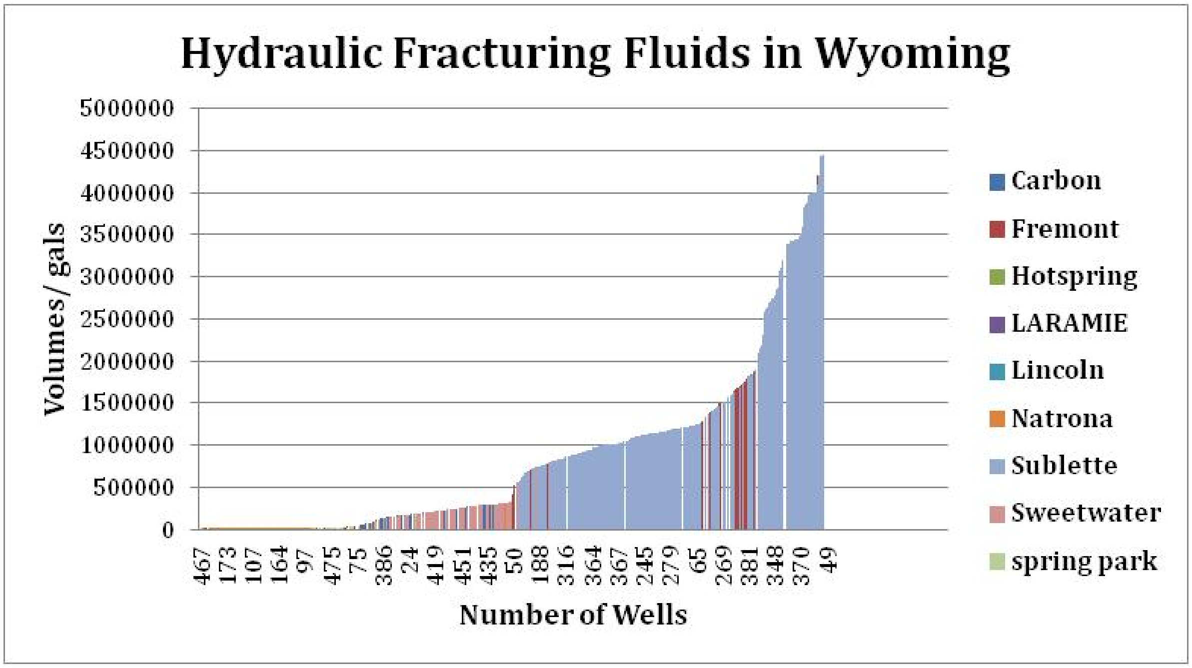


Figure 87. Volumes of hydraulic fracturing water (fracfocus.org)

Produced Water

Table 45 expresses the total oil, gas, and water produced within the Green River Basin from 2007–2011.

Table 45. Production of Oil, Gas, and Water in Green River Basin (WOGCC 2012)

Year	Oil Production (barrels)	Gas Production (Mcf)	Water Production (Barrels)
2007	15,491,483	1,218,888,397	125,613,453
2008	15,824,924	1,371,741,392	150,830,391
2009	15,925,806	1,428,200,434	158,560,401
2010	20,544,588	1,418,379,334	169,901,204
2011	15,385,222	1,347,348,632	177,151,681

Table 46 provides injection volumes by field, although not all fields are represented.

Table 46. Injection Volumes (WOGCC 2012)

Field	2007 (bbl)	2008 (bbl)	2009 (bbl)	2010 (bbl)	2011 (bbl)
Big Piney	577,239	167,646	189,178	70,354	40,247
Bison Basin	1,989,960	2,564,857	2,223,756	2,354,332	2,296,464
Brady	4,419,146	2,612,544	1,943,879	2,003,854	4,688,163
Cow Creek	4,406,339	8,174,082	4,635,125	5,517,186	6,288,081
Fontenelle	111,267	117,390	115,376	110,948	102,167
Green River Bend	592,890	381,857	549,775	616,873	432,311
Jonah	1,367,707	2,010,190	1,588,080	1,991,187	2,703,926

Field	2007 (bbl)	2008 (bbl)	2009 (bbl)	2010 (bbl)	2011 (bbl)
LaBarge	167,441	1,653,772	1,752,291	2,079,953	1,344,187
Lost Soldier	23,577,864	25,017,789	32,557,565	29,490,274	37,367,198
Mahoney Dome	926,644	721,983	1,188,006	1,085,123	1,111,673
McDonald Draw	535,996	494,630	414,810	388,833	377,482
Patrick Draw	1,551,255	4,012,343	1,196,017	1,020,284	1,179,744
Pinedale	954,458	6,749,055	11,951,930	12,027,080	11,482,543
Saddle Ridge	221,413	206,610	227,843	231,330	208,498
Star Corral	288,567	221,015	172,686	190,853	175,222
Tierney	1,083,636	1,813,532	1,660,262	1,831,283	1,004,778
Tip Top	455,781	548,822	427,670	387,878	389,175
WC	16,900,921	33,853,193	31,456,801	24,984,327	12,428,968
Wertz	20,610,169	25,384,888	1,953,919	24,188,672	30,240,574

Severity of Environmental Impact Matrix

Table 47 shows the categorization of environmental impacts for shale gas operations.

Table 47. Severity of Environmental Impact (Wiseman 2012)

Severity of environmental effect	Activity for which violation occurred	Enforcement action	Environmental factors
Procedural	- Permitting - Reporting - Testing - Financial assurance	"All ranges (violation noted" through notice of violation and/or administrative order)	No indication in violation/field notes that failure to obtain permit, report, conduct a test, or provide financial guarantee resulted in environmental damage
Minor - no effect	- Equipment failures - Pit construction, operation, and maintenance - Failure to prevent oil and gas waste - Commingling oil and gas - Site maintenance, such as moving weeds - Sign posting and hazard labels	"All ranges (violation noted" through notice of violation and/or administrative order)	No indication in field notes that violation resulted in any environmental damage
Minor effect	- Equipment failures that led to release - Pit construction, operation, and maintenance that led to release - Air pollution - Spills - Disposal	Violation noted, or NOV/administrative order paired with very small environmental effect	Small spills and improperly disposed wastes (typically less than 5 barrels of produced water or oil) that did not move offsite or otherwise suggest substantial environmental damage. Small quantities of air emissions (e.g., slightly over the daily limit).
Substantial	- Equipment failures that led to release - Pit construction, operation, and maintenance that led to release - Failure to plug well twelve months after abandonment or inactivity - Air pollution - Spills - Disposal	Violation noted, or NOV/administrative order + substantial environmental effect; remediation order	Medium spills and improperly disposed wastes (typically more than 5 barrels and less than 10 for produced water or oil that stayed on site). For fracturing fluid spills, any spill more than 1 barrel was considered major.
Major	- Equipment failures that led to release - Pit construction, operation, and maintenance that led to release - Air pollution - Spills - Disposal	Violation noted, or NOV/administrative order + > substantial environmental effect (or high penalty + substantial environmental effect); remediation order + major environmental effect	Large spills or improperly disposed of wastes (typically 10 or more barrels, small to large spills that moved off site and impacted a resource (e.g., drainage ditch, wetland). Any spill of fracturing fluid > 1 barrel.

Appendix E: Assumptions Used in ReEDS

What is ReEDS?[250]

The Regional Energy Deployment System is an optimization model used to assess the deployment of electric power generation technologies and transmission infrastructure throughout the contiguous United States into the future. The model, developed by NREL, is designed to analyze critical energy issues in the electric sector, especially with respect to the effect of potential energy policies such as clean energy and renewable energy standards or carbon restrictions.

ReEDS provides a detailed treatment of electricity-generating and electrical storage technologies, and specifically addresses a variety of issues related to renewable energy technologies—including accessibility and cost of transmission, regional quality of renewable resources, seasonal and diurnal generation profiles, variability of wind and solar power, and the influence of variability on the reliability of the electrical grid. ReEDS addresses these issues through a highly discretized regional structure, explicit statistical treatment of the variability in wind and solar output over time, and consideration of ancillary services requirements and costs.

Qualitative Model Description

To assess competition among the many electricity generation, storage, and transmission options throughout the contiguous United States, ReEDS chooses the cost-optimal mix of technologies that meet all regional electric power demand requirements, based on grid reliability (reserve) requirements, technology resource constraints, and policy constraints. This cost-minimization routine is performed for each of twenty 2-year periods from 2010 to 2050. The major outputs of ReEDS include the amount of generator capacity and annual generation from each technology, storage capacity expansion, transmission capacity expansion, total electric sector costs, electricity price, fuel prices, and CO_2 emissions. Time in ReEDS is subdivided within each 2-year period, with each year divided into four seasons with a representative day for each season, which is further divided into four diurnal time slices. Also, there is one additional summer-peak time slice. These 17 annual time slices enable ReEDS to capture the intricacies of meeting electric loads that vary throughout the day and year—with both conventional and renewable generators.

Although ReEDS includes all major generator types, it has been designed primarily to address the market issues that are of the greatest significance to renewable energy technologies. As a result, renewable and carbon-free energy technologies and barriers to their adoption are a focus. Diffuse resources such as wind and solar power come with concerns that conventional dispatchable power plants do not have, particularly regarding transmission and variability. The ReEDS model examines these issues primarily by using a much greater level of geographic disaggregation than do other long-term, large-scale, capacity expansion models. ReEDS uses 356 different resource regions in the continental United States. These 356 resource supply regions are grouped into four levels of larger regional groupings—balancing areas, reserve-sharing groups,

[250] "What is ReEDS?" is taken from the 2011 detailed documentation for the ReEDS model.
Short, W., et al., Regional Energy Deployment System (ReEDS). NREL Technical report NREL/TP-6A20-46534, August 2011. http://www.nrel.gov/analysis/reeds/.

North American Electric Reliability Council regions,[251] and interconnects. States are also represented for the inclusion of state policies.

Many of the data inputs in ReEDS are tied to these regions and derived from a detailed GIS model/database of the wind and solar resource, transmission grid, and existing plant data. The geographic disaggregation of renewable resources enables ReEDS to calculate transmission distances, as well as the benefits of dispersed wind farms, PV arrays, or CSP plants supplying power to a demand region. Offshore wind is distinguished from onshore wind both in terms of technology cost/performance and resources. The wind and CSP supply curves are subdivided into five resource classes based on the quality of the resource—strength and dependability of wind or solar isolation.

Regarding resource variability and grid reliability, ReEDS also allows electric and thermal storage systems to be built and used for load shifting, resource firming, and ancillary services. Four varieties of storage are supported: pumped hydropower, batteries, compressed air energy storage, and thermal storage in buildings.

Along with wind and solar power data, ReEDS provides supply curves for hydropower, biomass, and geothermal resources in each of the 134 balancing areas. The geothermal and hydropower supply curves are in megawatts of recoverable capacity, and the biomass supply curve is in million British thermal units of annual feedstock production. In addition, other carbon-reducing options are considered. Nuclear power is an option, as is CCS on some coal and natural gas plants. CCS is treated simply, with only an additional capital cost for new coal and gas-fired power plants for the extra equipment and an efficiency penalty to account for the parasitic loads of the separation and sequestration process. Also, a limited set of existing coal plants can choose to retrofit to CCS for an associated cost, as well as a performance, penalty. The major conventional electricity-generating technologies considered in ReEDS include hydropower, simple- and combined-cycle natural gas, several varieties of coal, oil/gas steam, and nuclear. These technologies are characterized in ReEDS by the following:

- Capital cost ($/MW)
- Fixed and variable operating costs ($/MWh)
- Fuel costs ($/MMBtu)
- Heat rate (MMBtu/MWh)
- Construction period (years)
- Equipment lifetime (years)
- Financing costs (such as nominal interest rate, loan period, debt fraction, debt-service-coverage ratio)
- Tax credits (investment or production)

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[251] North American Electric Reliability Corporation, October 2010. "2010 Long-Term Reliability Assessment." http://www.nerc.com/files/2010%20LTRA.pdf. Accessed November 2, 2011.

- Minimum turndown ratio (%)
- Quick-start capability and cost (%, $/MW)
- Spinning reserve capability
- Planned and unplanned outage rates (%).

Renewable and storage technologies are governed by similar parameters—accounting for fundamental differences. For instance, heat rate is replaced with round-trip efficiency in pure storage technologies, and the dispatchability parameters—such as fuel cost, heat rate, turndown ratio, and operating reserve capability—are not used for non-dispatchable wind and solar technologies. These variable generation technologies are further characterized by changes in generation levels over the course of a year.

The model includes consideration of distinguishing characteristics of each conventional generating technology. There are several types of coal-fired power plants within ReEDS, including pulverized coal with and without sulfur dioxide scrubbers, advanced pulverized coal, integrated gasification combined cycle, biomass co-firing, and integrated gasification combined cycle with CCS options. Coal-plant generation is discouraged from daily cycling via a cost penalty, which represents a combination of additional fuel burned, heat rate drop-off, and mechanical wear-and-tear. Natural gas plants represented in ReEDS include simple-cycle combustion turbines, combined-cycle plants, and combined-cycle with CCS plants. Combined-cycle natural gas plants can provide some spinning reserve and quick-start capability, and simple-cycle gas plants can be used cheaply and easily for quick-start power. Nuclear power is represented as one technology in ReEDS and is considered to be baseload.

Retirement of conventional generation and hydropower can be modeled through exogenous specification of planned retirements or based on usage characteristics of the plants. All retiring non-hydro renewable plants are assumed to be refurbished or replaced immediately because the site is already developed and has transmission access and other infrastructure.

ReEDS tracks emissions of carbon and sulfur dioxide from both generators and storage technologies. Caps can be imposed at the national level for these emissions, and constraints can also be applied to impose caps at state or regional levels. There is another option of applying a carbon tax instead of a cap; the tax level and ramp-in pattern can be defined exogenously. In addition, ReEDS can impose clean energy or renewable energy standards at the regional or national level.

Annual electric loads and fuel price supply curves are exogenously specified to define the system boundaries for each period of the optimization. To allow for the evaluation of scenarios that might depart significantly from the Reference scenario, price elasticity of demand is integrated into the model: the exogenously defined demand projection can be adjusted up or down based on a comparison of an estimated business-as-usual electricity price path and a calculation of electricity price within the model for each of the twenty 2-year periods. For coal and natural gas pricing, supply curves based on the Annual Energy Outlook[252] have been developed and used in ReEDS.

Natural Gas Supply Curve Background and Development

The EIA's Annual Energy Outlook 2011 has two specific scenarios that attempt to model the effects of high or low abundance of natural gas supply: High-EUR and Low-EUR. The High-EUR scenario increases the total unproved technically recoverable shale gas resource from 827 Tcf in the Mid-EUR baseline scenario to 1,230 Tcf. In addition, the ultimate recovery per shale gas well is 50% higher than in the baseline scenario. Low-EUR reduces recoverable shale gas resource to 423 Tcf and 50% lower ultimate recovery per shale gas well than in the Mid-EUR baseline scenario.

Deriving the coefficients for this study relied on assuming a linear regression model and employing an ordinary least-squares method. Linear regression is a statistical technique that examines the relationship between one dependent variable (Y) and multiple explanatory variables, or regressors (X), taking the linear form:

$$Y_i = \beta_0 + \beta_1 * X_1 + \beta_2 * X_2 + \cdots \beta_n * X_n + \varepsilon_i$$

The estimated coefficients represent the marginal impact of a 1-unit change in each independent variable $\mathbf{X_i}$ on Y. Linear regression is often used for prediction or forecasting.[253]

In this case, because the objective was to develop a model to closely model the relationship between natural gas in the electric sector and consumption in the electric sector in different scenarios, the electric-sector price was modeled based on the following predictors: electric-sector consumption, economy-wide consumption, year (2012–2035), and the natural gas scenario case.[254] Each electric-sector price for each of the Annual Energy Outlook scenarios from 2012–2035 was treated as an independent observation used to estimate coefficients in the following model:

$$\begin{aligned} \mathit{Electric\ Sector\ Price}_i &= \beta_0 + \beta_1 * \mathit{Electric\ Sector\ Consumption}_i + \beta_2 \\ &* \mathit{Economy-wide\ Consumption}_i \\ &+ \sum_{j=1}^{12} \beta_j * \mathit{Year} + \sum_{k=1}^{4} \beta_k * \mathit{Natural\ Gas\ Scenario} + \varepsilon_i \end{aligned}$$

Observations that occurred in High-EUR and Low-EUR were coded accordingly, creating two additional intercept shifter "dummy" variables. The year, rather than coded as continuous, was coded as a dummy variable to capture non-linear variation from year to year. To account for the

[252] Annual Energy Outlook 2011. DOE/EIA-0383. Washington, DC: U.S. Energy Information Administration.
[253] Damodar, Gujarati. Basic Econometrics (5th edition). McGraw Hill, 2007.
[254] Data for 2008–2011 as well as outlier scenarios (polmax0314a, polmaxlco20321a, polmaxlp0316a, lgbama050218a, lgbama200218a, aeo2010r1118a, oghtec110209a, ogltec110209a, hilng110209a, lolng110209a) were removed when running the model.

predictor influence of economy-wide consumption, the average value for the year and the scenario for each data point were multiplied by β_2 (the derived electric-sector consumption coefficient). As a result, the intercept varied by year and by scenario, while the slope remained the same across year and scenario. The intercept and shifter for the years 2036–2050 was held constant with model results in 2035.

The following tables summarize the assumptions used in ReEDS for: technology costs and performance (Table 48), wind performance (Table 49), CSP performance (Table 50), and utility-scale PV performance (Table 51).

Table 48. Technology Cost ($2010) and Performance Assumptions Used in ReEDS

	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (MMBtu/MWh)
Coal Integrated Gasification Combined-Cycle CCS				
2010	4,075	7	32	9.0
2020	4,075	7	32	9.0
2030	4,075	7	32	7.9
2040	4,075	7	32	7.9
2050	4,075	7	32	7.9
CSP				
2010	7,179 (8,217)[a]	NA	50 (80)	NA
2020	6,639 (4,077)	NA	50 (66)	NA
2030	5,398 (2,983)	NA	50 (51)	NA
2040	4,778 (2,983)	NA	50 (47)	NA
2050	4,778 (2,983)	NA	50 (45)	NA
Combined-Cycle Plants				
2010	1,250	4	6	7.5
2020	1,250	4	6	6.7
2030	1,250	4	6	6.7
2040	1,250	4	6	6.7
2050	1,250	4	6	6.7
Combined-Cycle Plants CCS				
2010	3,348	10	19	10.0
2020	3,267	10	19	10.0
2030	3,267	10	19	10.0
2040	3,267	10	19	10.0
2050	3,267	10	19	10.0
Simple-Cycle Combustion Turbines				
2010	661	30	5	12.5
2020	661	30	5	10.3
2030	661	30	5	10.3
2040	661	30	5	10.3
2050	661	30	5	10.3

		Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (MMBtu/MWh)
New Coal					
	2010	2,937	4	23	10.4
	2020	2,937	4	23	9.4
	2030	2,937	4	23	9.0
	2040	2,937	4	23	9.0
	2050	2,937	4	23	9.0
Nuclear					
	2010	6,199 (3,100)	NA	129	9.7
	2020	6,199 (3,100)	NA	129	9.7
	2030	6,199 (3,100)	NA	129	9.7
	2040	6,199 (3,100)	NA	129	9.7
	2050	6,199 (3,100)	NA	129	9.7
Utility-Scale PV					
	2010	4,067 (4,067)	NA	51 (21)	NA
	2020	2,560 (2,013)	NA	46 (20)	NA
	2030	2,351 (1,912)	NA	42 (15)	NA
	2040	2,191 (1,797)	NA	38 (13)	NA
	2050	2,058 (1,720)	NA	33 (9)	NA
Wind Offshore					
	2010	3,702 (3,702)	0 (23)	101 (16)	NA
	2020	3,355 (3,284)	0 (17)	101 (16)	NA
	2030	3,042 (2,912)	0 (14)	101 (16)	NA
	2040	3,042 (2,744)	0 (12)	101 (16)	NA
	2050	3,042 (2,744)	0 (12)	101 (16)	NA
Wind Onshore					
	2010	2,012 (2,012)	0 (8)	60 (12)	NA
	2020	2,012 (1,964)	0 (5)	60 (12)	NA
	2030	2,012 (1,865)	0 (5)	60 (12)	NA
	2040	2,012 (1,805)	0 (5)	60 (12)	NA
	2050	2,012 (1,805)	0 (5)	60 (12)	NA

[a] Advanced RE Scenario assumptions displayed in parentheses

Table 49. Wind Performance Assumptions

	Wind Power Class	On-Shore Wind	Off-Shore Wind
2010			
	Class 3	0.32 (0.35)[a]	0.36 (0.37)
	Class 4	0.36 (0.39)	0.39 (0.41)
	Class 5	0.42 (0.43)	0.45 (0.44)
	Class 6	0.44 (0.46)	0.48 (0.48)
	Class 7	0.46 (0.50)	0.50 (0.52)

	Wind Power Class	On-Shore Wind	Off-Shore Wind
2020			
	Class 3	0.33 (0.38)	0.37 (0.39)
	Class 4	0.37 (0.42)	0.39 (0.44)
	Class 5	0.42 (0.45)	0.45 (0.47)
	Class 6	0.44 (0.48)	0.48 (0.51)
	Class 7	0.46 (0.52)	0.50 (0.55)
2030			
	Class 3	0.35 (0.38)	0.38 (0.40)
	Class 4	0.38 (0.43)	0.40 (0.45)
	Class 5	0.43 (0.46)	0.45 (0.48)
	Class 6	0.45 (0.49)	0.48 (0.51)
	Class 7	0.46 (0.53)	0.50 (0.55)
2040			
	Class 3	0.35 (0.38)	0.38 (0.40)
	Class 4	0.38 (0.43)	0.40 (0.45)
	Class 5	0.43 (0.46)	0.45 (0.48)
	Class 6	0.45 (0.49)	0.48 (0.51)
	Class 7	0.46 (0.53)	0.50 (0.55)
2050			
	Class 3	0.35 (0.38)	0.38 (0.40)
	Class 4	0.38 (0.43)	0.40 (0.45)
	Class 5	0.43 (0.46)	0.45 (0.48)
	Class 6	0.45 (0.49)	0.48 (0.51)
	Class 7	0.46 (0.53)	0.50 (0.55)

[a] Advanced RE Scenario assumptions displayed in parentheses

Table 50. CSP Performance Assumptions

	Wind Power Class	Capacity Factor
2010		
	Class 1	0.28 (0.28)[a]
	Class 2	0.37 (0.37)
	Class 3	0.42 (0.42)
	Class 4	0.44 (0.44)
	Class 5	0.46 (0.46)
2020		
	Class 1	0.28 (0.37)
	Class 2	0.37 (0.47)
	Class 3	0.42 (0.52)
	Class 4	0.44 (0.54)
	Class 5	0.46 (0.56)
2030		
	Class 1	0.37 (0.37)

	Wind Power Class	Capacity Factor
	Class 2	0.47 (0.47)
	Class 3	0.52 (0.52)
	Class 4	0.54 (0.54)
	Class 5	0.56 (0.56)
2040		
	Class 1	0.37 (0.37)
	Class 2	0.47 (0.47)
	Class 3	0.52 (0.52)
	Class 4	0.54 (0.54)
	Class 5	0.56 (0.56)
2050		
	Class 1	0.37 (0.37)
	Class 2	0.47 (0.47)
	Class 3	0.52 (0.52)
	Class 4	0.54 (0.54)
	Class 5	0.56 (0.56)

[a] Advanced RE Scenario assumptions displayed in parentheses

Table 51. Utility-Scale PV Performance Assumptions

Year	Capacity Factor
2010	0.16–0.27
2020	0.16–0.27
2030	0.16–0.27
2040	0.16–0.27
2050	0.16–0.27

Treating Plant Retirement in ReEDS[255]

Assumptions about the retirement of conventional-generating units can have considerable cost implications. Considerations that go into the decision-making process on whether or not an individual plant should be retired involve a number of factors—specifically, the economics of plant operations and maintenance. Projecting these economic considerations into the future given the uncertainties involved is beyond the scope of ReEDS. Instead, ReEDS uses the following three retirement options that are not strictly economic:

- *Scheduled lifetimes for existing coal, gas, and oil.* These retirements are based on lifetime estimate data for power plants from Ventyx (2010). Near-term retirements are based on the officially reported retirement date as reported by EIA 860, EIA 411, or Ventyx unit research (Ventyx 2010). If there is no officially reported retirement date, a lifetime-based

[255] This section was taken from existing documentation of the ReEDS model.
Short, W. et al. (2011). "Regional Energy Deployment System (ReEDS)," NREL Technical report NREL/TP-6A20-46534, August 2011. http://www.nrel.gov/analysis/reeds/.

retirement is estimated based on the unit's commercial online date and the following lifetimes:

  - Coal units (< 100 MW) = 65 years
  - Coal units (> 100 MW) = 75 years
  - Natural gas combined-cycle unit = 55 years
  - Oil-gas-steam unit = 55 years

- *Usage-based retirements of coal.* In addition to scheduled retirements, coal technologies, including co-fired coal with biomass, can retire based on proxies for economic considerations. Any capacity that remains unused for energy generation or operating reserves for 4 consecutive years is assumed to retire. Coal capacity is also retired by requiring a minimum annual capacity factor; after every 2-year investment period, if a coal unit has a capacity factor of less than this minimum capacity factor during the 2-year period, an amount of coal capacity is retired such that the capacity factor increases to this minimum threshold (10% in 2030, 20% in 2040, and 30% in 2050). Coal plants are not retired under this algorithm until after 2020.
- *Scheduled nuclear license-based retirements.* Nuclear power plants are retired based on the age of the plant. Under default assumptions, older nuclear plants that are on line before 1980 are assumed to retire after 60 years (one re-licensing renewal), whereas newer plants (on line during or after 1980) are assumed to retire after 80 years (two relicensing renewals). Other options can be implemented, such as assuming 60- or 80-year lifetimes for all nuclear plants.

Glossary

annulus	The space between two concentric lengths of pipe or between pipe and the hole in which it is located.
associated gas	Natural gas that occurs with crude oil reservoirs, either as free gas or dissolved in solution. It is usually produced with crude oil.
basin	A petroleum geology term that refers to a dip in the Earth's crust usually filled or being filled with sediment. Basins are usually relatively large areas where oil and gas can be found.
billion cubic feet (bcf)	Unit used to measure large quantities of gas, approximately equal to 1 trillion British thermal units.
billion cubic feet per day (bcf/d)	Unit used to measure the daily volume of gas produced, stored, transported, or consumed.
bradenhead	A device that is used during inner-string grouting or pressure grouting operations. The bradenhead is situated at the top of the well casing, where it allows a drill pipe to be extended into the well while the well head is sealed and the annulus between the well casing and drill pipe is pressurized. Also termed casing head, cement head, or largen head.
British thermal unit (Btu)	An energy unit equivalent to the amount of energy needed to raise the temperature of 1 pound of water 1°F from 58.5°F to 59.5°F under standard pressure of 30 inches of mercury. Commonly used for measuring gas and other energy sales quantities.
burner tip	The point of end-use consumption of a particular fuel.
cement bond log	A representation of the integrity of the cement job, especially whether the cement is adhering solidly to the outside of the casing. The log is typically obtained from one of a variety of sonic-type tools.
coal-bed methane (CBM)	Natural gas, primarily methane, generated during coal formation and recovered by pumping water from coal seams, allowing gas to escape through shallow wells. It is generally referred to as one type of unconventional gas.
closed-loop drilling	Drilling and fracturing operation that contains all fluids in tanks and other closed-to-the-atmosphere equipment. Closed-loop drilling does not use open pits and therefore can reduce the risks of leaks and spills.
Combined-cycle	An electric generating technology in which conventional gas combustion turbines are combined with heat-recovery, steam-powered generation units, increasing the overall efficiency of the generating facility. Electricity is produced from both the feed gas, as well as from otherwise lost waste heat exiting gas turbines. In a conventional steam power generating facility, electricity is generated only from the feed gas.
completion	Preparing a newly drilled well for production; usually involves setting casing (pipe that lines the interior of a well to prevent caving and protect against ground-water contamination) and perforating the casing to establish communication with the producing formation.
compressed natural gas	Highly compressed natural gas stored and transported in high-pressure containers, typically greater than 3,000 pounds per square inch (200 bar); commonly used for transport fuel.
condensates	Light hydrocarbon compounds that condense into liquid at surface temperatures and pressures. They are generally produced with natural gas.
cubic feet (cf)	Common unit of measurement of gas volume equivalent to the amount of gas required to fill a volume of 1 cubic foot under given temperature and pressure conditions.

deep-well injection	Technique for disposal of frac flowback or produced water in deep formations isolated from producing zones and fresh-water aquifers.
dry gas	Natural gas, mainly methane, that remains after liquid hydrocarbon components have been removed, making it suitable for pipeline shipping, liquefied natural gas processing, or industrial usage.
ethane (C_2H_6)	A normally gaseous natural gas liquid hydrocarbon extracted from natural gas or refinery gas streams.
flaring	The process of disposing uncommercial or otherwise unwanted gas by burning. Operators often flare associated gas in regions with limited gas markets.
formation	Refers to either a certain layer of the Earth's crust, or a certain area of a layer; often refers to the area of rock where a petroleum or natural gas reservoir is located.
fracturing (or fracking)	See hydraulic fracturing.
frac flowback	Fluids that are returned to the surface immediately following hydraulic fracturing that include mostly the injected water, sand, and chemicals used for the fracturing.
geographic information system (GIS)	Integrated hardware, software, and data used for capturing, managing, analyzing, and displaying all forms of geographically referenced information.
gas-to-liquids process	A process that converts natural gas into synthetic liquid petroleum products, such as diesel fuel and blending feedstock.
glycol dehydrators	Facilities in which a glycol-based process removes water from produced natural gas, often in the field and before processing. The removal of water is needed to prevent corrosion and water freezing in pipelines.
green completion	Using technology to recover gas that may otherwise be vented or flared during the completion phase of a natural gas well. Also known as reduced emission completions.
harmonization	A meta-analytical procedure for adjusting published estimates from life cycle assessment to develop a set of directly comparable estimates. Harmonization clarifies a body of published estimates in ways useful to decision-making and future analyses. See nrel.gov/harmonization for further description and resources.
hydraulic fracturing (or hydrofracking)	The process of creating fractures in non-porous rock using specially formulated, water-based solutions forced into wells at extremely high pressure; the cracks in the rock allow for the release and collection of the natural gas. Fracking can be done in vertical or horizontal wells.
induced seismicity	Seismic activity (e.g., earthquakes) that is caused by injection of fluids into deep formations in proximity to natural faults.
life cycle assessment (LCA)	A technique to assess environmental impacts associated with all stages of a product's life from "cradle to grave" (i.e., from raw material extraction through materials processing, manufacture, distribution, use, repair and maintenance, and disposal or decommissioning). LCAs can be applied to water, energy, greenhouse gas emissions, or other metrics of interest.
liquefied natural gas (LNG)	Natural gas, mainly methane, that has been cooled to very low temperature (-259°F) so that it will condense into a transportable colorless and odorless liquid.
methane (CH_4)	The lightest and most abundant of the hydrocarbon gases, it is the principal component of natural gas and LNG.
natural gas	Naturally occurring mixture of hydrocarbon gases from underground sources composed mainly of methane (more than 85% in some cases), ethane, propane, butane, pentane, and impurities including carbon dioxide, helium, nitrogen, and hydrogen sulfide.

natural gas liquids	Natural gas components—including ethane, propane, butane, pentane, and condensates—that are liquid at surface conditions. It does not include methane, which remains in gaseous phase at surface conditions.
New York Mercantile Exchange	The first U.S. exchange to trade natural gas futures contracts; the New York Mercantile Exchange has contracts with major delivery points.
play (shale play, shale gas play)	A geographic area that has been targeted for exploration due to favorable geoseismic survey results, well logs, or production results from a new well in the area. An area comes into play when it is generally recognized that there is an economic quantity of oil or gas to be found.
primacy (primary enforcement responsibility)	The authority to implement the Underground Injection Control Program. To receive primacy, a state, territory, or tribe must demonstrate to EPA that its Underground Injection Control Program is at least as stringent as the federal standards; the state, territory, or tribal Underground Injection Control requirements may be more stringent than the federal requirements. EPA may grant primacy for all or part of the Underground Injection Control Program (e.g., for certain classes of injection wells).
produced water	Water that is extracted with the oil and gas from the producing formation. Produced water is usually highly saline and not usable without treatment.
quad	A unit of energy equal to 10^{15} Btu, roughly equal to 1 Tcf.
reserves	Volumes of hydrocarbons that have a chance of being economically and technically producible.
reservoir	A subsurface rock or formation having sufficient porosity and permeability to store and transmit fluids such as gas, oil, and water. Reservoirs are typically composed of sedimentary rocks with an overlying or adjoining impermeable seal or cap rock.
shale gas	Shale gas is defined as a natural gas produced from shale rock. Shale has low matrix permeability; therefore, gas production in commercial quantities requires fracturing or other stimulation to improve permeability.
social license to operate	A project that has the ongoing approval within the local community and other stakeholders, ongoing approval or broad social acceptance, and, most frequently, as ongoing acceptance.
trillion cubic feet (Tcf)	Unit used to measure large quantities of gas, typically reserve sizes. Approximately equal to 1 quad of energy.
unconventional gas	Unconventional gas refers to gas produced from coal seams (coal-bed methane), shale rocks (shale gas), and rocks with low permeability (tight gas). Once gas is produced from these reservoirs, it has the same properties of gas produced from conventional (i.e., sedimentary reservoirs with high porosity and permeability) sources. Unconventional gas may have high levels of natural gas liquids (an exception is coal-seam gas, which tends to be very dry with high proportion of methane versus natural gas liquids) and may have low or high levels of carbon dioxide and high and low levels of sulfur (sour or sweet). Because unconventional reservoirs have low permeability, artificial methods to increase gas flows, such as mechanical or chemical fracking, is often required before the wells are able to produce commercial quantities of gas.

Underground Injection Control Program	The program that EPA, or an approved state, is authorized to implement under the Safe Drinking Water Act that is responsible for regulating the underground injection of fluids. This includes setting the minimum federal requirements for construction, operation, permitting, and closure of underground injection wells. There are six categories of wells regulated under the Underground Injection Control ranging from Class I to Class VI. Class I wells are the most technologically sophisticated and are used to inject wastes into deep, isolated rock formations below the lowermost underground source of drinking water. Class I wells may inject hazardous waste, non-hazardous industrial waste, or municipal wastewater. Class II wells are typically used by the oil and gas industry to inject brines and other fluids associated with oil and gas production, or storage of hydrocarbons.
volatile organic compound (VOC)	Gases and vapors, such as benzene, released by petroleum refineries, natural gas drilling, petrochemical plants, plastics manufacturing, and the distribution and use of gasoline. VOCs include carcinogens and chemicals that react with sunlight and nitrogen oxides to form ground-level ozone, a component of smog.
water recycling	Collection of frac flowback or produced water and treating the fluid for beneficial use that include hydraulic fracturing, agriculture, or release to streams.
well completion	Well completion incorporates the steps taken to transform a drilled well into a producing one. These steps usually include casing, cementing, perforating, gravel packing, and installing a production tree.
well head	The assembly of fittings and valve equipment used for producing a well and maintaining surface control of a well.
wet gas	Natural gas with significant natural gas liquid components. Also sometimes called rich gas.
workover	Work performed in a well after its completion in an effort to secure production where there has been none, restore production that has ceased, or increase production. Workovers for unconventional wells involve re-fracturing (re-stimulation).

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Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation

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The U.S. Department of Energy (DOE) estimates that in the coming decades the United States' natural gas (NG) demand for electricity generation will increase. Estimates also suggest that NG supply will increasingly come from imported liquefied natural gas (LNG). Additional supplies of NG could come domestically from the production of synthetic natural gas (SNG) via coal gasification−methanation. The objective of this study is to compare greenhouse gas (GHG), SO_x, and NO_x life-cycle emissions of electricity generated with NG/LNG/SNG and coal. This life-cycle comparison of air emissions from different fuels can help us better understand the advantages and disadvantages of using coal versus globally sourced NG for electricity generation. Our estimates suggest that with the current fleet of power plants, a mix of domestic NG, LNG, and SNG would have lower GHG emissions than coal. If advanced technologies with carbon capture and sequestration (CCS) are used, however, coal and a mix of domestic NG, LNG, and SNG would have very similar life-cycle GHG emissions. For SO_x and NO_x we find there are significant emissions in the upstream stages of the NG/LNG life-cycles, which contribute to a larger range in SO_x and NO_x emissions for NG/LNG than for coal and SNG.

1. Introduction

Natural gas currently provides 24% of the energy used by United States homes (*1*). It is an important feedstock for the chemical and fertilizer industry. Low wellhead gas prices (less than \$3/thousand cubic feet (Mcf) (*2*)) spurred a surge in construction of natural-gas-fired power plants: between 1992 and 2003, while coal-fired capacity increased only from 309 to 313 GW, natural-gas-fired capacity more than tripled, from 60 to 208 GW (*3*). Adding to this was the Energy Information Agency's (EIA) prediction of continued low natural gas prices (around \$4/Mcf) through 2020 (*4*), lower capital costs, shorter construction times, and generally lower air emissions for natural-gas-fired plants that allowed power generators to meet the clean air standards (*5*). However, instead of remaining near projected levels, the average wellhead price of natural gas peaked at \$11/Mcf in October 2005 (*6*). This price increase made natural gas uneconomical as a feedstock, so most natural-gas-fired plants are operating below capacity (*7*). Despite these trends, natural gas consumption is expected to increase by 20% of 2003 levels by 2030. Demand from electricity generators is projected to grow the fastest. At the same time, natural gas production in the United States and pipeline imports from Canada and Mexico are expected to remain fairly constant (*8*). The gap between North American supply and U.S. demand can only be met with alternative sources of natural gas, such as imported liquefied natural gas (LNG) or synthetic natural gas (SNG) produced from coal. Current projections by EIA estimate that LNG imports will increase to 16% of the total U.S. natural gas supply by 2030 (*8*). Alternatively, Rosenberg et al. call for congress to promote gasification technologies that use coal to produce SNG. This National Gasification Strategy calls for the United States to produce 1.5 trillion cubic feet (tcf) of synthetic natural gas per year within the next 10 years (*7*), equivalent to 5% of expected 2030 demand.

The natural gas system is one of the largest sources of greenhouse gas emissions in the United States, generating around 132 million tons of CO_2 equivalents annually (*1*). Significant emissions of criteria air pollutants also come from upstream combustion life-cycle stages of the gas. Emissions from the emerging LNG life-cycle stages or from the production of SNG have not been studied in detail. If larger percentages of the U.S. supply of natural gas will come from these alternative sources, then LNG or SNG supply chain emissions become an important part of understanding overall natural gas life-cycle emissions. Also, comparisons between coal and natural gas that concentrate only on the emissions at the utility plant may not be adequate. The objective of this study is to perform a life-cycle analysis (*9*, *10*) of natural gas, LNG, and SNG. Direct air emissions from the processes during the life-cycle will be considered, as well as air emissions from the combustion of fuels and electricity used to run the process. A comparison with coal life-cycle air emissions will be presented, in order to have a better understanding of the advantages and disadvantages of using coal versus natural gas for electricity generation.

2. Fuel Life-Cycles

The natural gas life-cycle starts with the production of natural gas and ends at the combustion plant. Natural gas is extracted from wells and sent to processing plants where water, carbon dioxide, sulfur, and other hydrocarbons are removed. The produced natural gas then enters the transmission system. The U.S. transmission system also includes some storage of natural gas in underground facilities such as reconditioned depleted gas reservoirs, aquifers, or salt caverns to meet seasonal and/or sudden short-term demand. From the transmission and storage system, some natural gas goes directly to large-scale consumers, like electric power generators, which is modeled here. The rest goes into local distribution systems that deliver it to residential and commercial consumers via low-pressure, small-diameter pipelines.

The use of liquefied natural gas (LNG) adds three additional life-cycle stages to the natural gas life-cycle described above. Natural gas is produced and processed to remove contaminants and transported by pipeline relatively short distances to be liquefied. In the liquefaction process, natural gas is cooled and pressurized (*11*). Liquefaction plants are generally located in coastal areas of LNG exporting countries and dedicated LNG ocean tankers transport LNG

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to the United States. Upon arriving, the LNG tankers offload their cargo and the LNG is regasified. At this point the regasified LNG enters the U.S. natural gas transmission system.

The coal life-cycle is conceptually simpler than the natural gas life-cycle, consisting of three major steps: coal mining and processing, transportation, and use/combustion.

U.S. coal is produced from surface mines (67%), or underground mines (33%) (*1*). Mined coal is processed to remove impurities. Coal is then transported from the mines to the consumers via rail (84%), barge (11%), and trucks (5%) (*12*). More than 90% of the coal used in the United States is used by the electric power sector, which is modeled here (*8*).

The life-cycle of SNG is a combination of some stages from the coal life-cycle and some stages of the natural gas life-cycle. Coal is mined, processed, and transported, as in the coal life-cycle, to the SNG production plant. At this plant, syngas, a mixture of carbon monoxide (CO) and hydrogen (H_2), is produced by gasification and converted, via methanation, to methane and water. The SNG is then sent to the natural gas transmission system, described above, and on to the electric power generator.

3. Methods for Calculating Life-Cycle Air Emissions

In our study we investigate the life-cycle air emissions from coal, natural gas, LNG, and SNG use. All fossil fuel options are used to produce electricity and combustion emissions are included as a component of the each life-cycle. For GHG, the emissions factors at power plants used are 120 lb CO_2 equiv/MMBtu of natural gas and 205 lb CO_2 equiv/MMBtu of coal. The SO_x and NO_x emissions at power plants are presented in the results section and in the Supporting Information

3.1. Life-Cycle Air Emissions from Natural Gas produced in North America. In 2003, the total consumption of natural gas in the United States was over 27 trillion cubic feet (tcf). Of this, 26.5 tcf were produced in North America (U.S., Canada, and Mexico) (*13*). According to the Environmental Protection Agency (EPA), 1.07% of the natural gas produced is lost in its production, processing, transmission, and storage (*14*). Total methane emissions were calculated using the percentage of natural gas lost. It was also assumed that natural gas has an average heat content of 1030 Btu/ft^3 (*13*), and that 96% of the natural gas lost is methane, which has a density of 0.0424 lb/ ft^3 (*14*).

In 1993 the U.S. EPA established the Natural Gas STAR program to reduce methane emissions from the natural gas industry. Data from this program for the reductions in methane lost in the natural gas system, as described in the Supporting Information, were combined with the data described above to develop a range of methane emissions factors for the North American natural gas life-cycle stages.

Carbon dioxide emissions are produced from the combustion of natural gas used during various life-cycle stages and from the production of electricity consumed during transport. EIA provides annual estimates of the amount of natural gas used for the production, processing, and transport of natural gas. In 2003, approximately 1900 billion cubic feet of natural gas were consumed during these stages of the natural gas life-cycle (*13*). Total carbon dioxide emissions were calculated using a carbon content in natural gas of 31.90 lb C/MMBtu and an oxidation fraction of 0.995 (*1*). According to the Transportation Energy Data Book, 3 billion kWh were used for natural gas pipeline transport in 2003 (*15*). The average GHG emission factor from the generation of this electricity is 1400 lb CO_2 equiv/MWh (*16*). These CO_2 emissions were added to methane emissions to obtain the upstream combustion GHG emission factors for North American natural gas.

SO_x and NO_x emissions from the natural gas upstream stages of the life-cycle come from the combustion of the fuels used to produce the energy that runs the system, as given in the Supporting Information. Total emissions from flared gas were calculated using the AP 42 Emission Factors for natural gas boilers (*17*). A range of emissions from the combustion of the natural gas used during the upstream stages of the life-cycle was developed using the AP 42 Emissions Factors for reciprocating engines and for natural gas turbines (*17*). Emissions from generating the electricity used during natural gas pipeline operations were estimated using the most current average emission factors given by EGRID: 6.04 lb SO_2/MWh and 2.96 lb NO_x/MWh (*16*). Note that EGRID reports emissions of SO_2 only. Other references used in this paper report total SO_x emission. For this paper, sulfur emission will be reported in terms of SO_x emissions.

In addition to emissions from the energy used during the life-cycle of natural gas, SO_x emissions are produced in the processing stage of the life-cycle, when hydrogen sulfide (H_2S) is removed from the sour natural gas to meet pipeline requirements. A range of SO_x emissions from this processing of natural gas was developed using the AP 42 emissions factors for natural gas processing and for sulfur recovery (*17*). To use the AP 42 emission factors for sulfur recovery, we found that in 2003 1945 thousand tons of sulfur were recovered from 14.7 trillion cubic feet of natural gas resulting in a calculated average natural gas H_2S mole percentage of 0.0226. This was then used with the AP 42 emission factors for natural gas processing.

3.2. Air Emissions from the LNG Life-Cycle. In 2003, 500 billion cubic feet of natural gas were imported in the form of LNG (*13*). In 2003, 75% of the LNG imported to the United States came from Trinidad and Tobago, but this percentage is expected to decrease as more imports come from Russia, the Middle East, and Southeast Asia (*13*). According to EIA, the LNG tanker world fleet capacity should have reached 890 million cubic feet of liquid (equivalent to 527 billion cubic feet of natural gas) by the end of 2006 (*18*). There are currently 5 LNG terminals in operation in the United States, with a combined base load capacity of 5.3 billion cubic feet per day (about 2 trillion cubic feet per year). In addition to these terminals, there are 45 proposed facilities in North America, 18 of which have already been approved by the Federal Energy Regulatory Commission (FERC) (*19*).

Due to unavailability of data for emissions from natural gas production in other countries, it is assumed that natural gas imported to the United States in the form of LNG produces the same emissions from the production and processing life-cycle stages as North American natural gas. Those stages are incorporated for LNG. Most of the natural gas converted to LNG is produced from modern fields developed and operated by multinational oil and gas companies, so they are assumed to be operated in a similar way to those in the United States.

It is expected that transportation of natural gas from the production field to the liquefaction plant would have emissions similar to those of pipeline transport of domestic natural gas. But the emission factor for the U.S. system (which is included in the LNG life-cycle) is based on total pipeline distances of over 200 000 miles (*20*). Because LNG facilities are closely paired with gas fields, it is expected that the average distance from production field to a LNG facility would be much smaller than 200 000 miles. Also, because there were no reliable data for the myriad of fields and facilities and suspected impact on the overall life cycle would be minimal, this transport from the fields to the liquefaction terminals was ignored. This would slightly underestimate the emissions from the LNG life cycle.

Additional emission factors were developed for the liquefaction, transport, and regasification life-cycle stages of LNG. Tamura et al. have reported emission factors for the liquefaction stage in the range of 11−31 lb CO_2 equiv/MMBtu (*21*). The sources of these emissions are outlined in the Supporting Information.

LNG is shipped to the United States via LNG tankers. LNG tankers are the last ship type to use steam turbine technology in their engines. This technology allows for easy use of boil-off gas (BOG) in a gas boiler. Boil-off rates in LNG tankers range between 0.15% and 0.25% per day when loaded (*22*, *23*). When there is not enough BOG available, a fuel oil boiler is used to produce the steam. In addition to this benefit, steam turbines require less maintenance than diesel engines, which is beneficial to these tankers that have to be readily available to leave a terminal in case of emergency (*22*).

Most LNG tankers currently in operation have a capacity to carry between 4.2 and 5.3 million cubic feet of LNG (2.6 and 3.2 billion cubic feet of gas). There are smaller tankers available, but they are not widely used for transoceanic transport. There is also discussion about building larger tankers (8.8 million cubic feet), however none of the current U.S. terminals can handle tankers of this size (*18*).

The rated power of the LNG tankers ranges between 20 and 30 MW, and they operate under this capacity around 75% of the time during a trip (*24*, *25*). The energy required to power this engine is 11.6 MMBtu/MWh (*26*). As previously mentioned, some of this energy is provided by BOG and the rest is provided by fuel oil. A loaded tanker with a rated power of 20 MW, and 0.12% daily boil-off rate would consume 3.88 million cubic feet of gas per day and 4.4 tons of fuel oil per day. The same tanker would consume 115 tons of fuel oil per day on they way back to the exporting country operating under ballast conditions. A loaded tanker with a rated power of 30 MW, and a 0.25% daily boil-off rate would get all its energy from the BOG, with some excess gas being combusted to reduce risks of explosion (*22*). Under ballast conditions, the same tanker would consume 172 tons of fuel oil per day.

For LNG imported in 2003 the average travel distance to the Everett, MA LNG terminal was 2700 nautical miles (*13*, *27*). In the future LNG could travel as far as far as 11 700 nautical miles (the distance between Australia and the Lake Charles, LA LNG terminal (*27*)). This range of distances is representative of distances from LNG countries to U.S. terminals that could be located on either the East or West coasts. To estimate the number of days LNG would travel (at a tanker speed of 20 knots (*22*)), these distances were used. This trip length can then be multiplied by the fuel consumption of the tanker to estimate total trip fuel consumption and emissions, and these can then be divided by the average tanker capacity to obtain a range of emission factors for LNG tanker transport between 2 and 17 lb CO_2 equiv/MMBtu.

Regasification emissions were reported by Tamura et al. to be 0.85 lb CO_2 equiv/MMBtu (*21*). Ruether et al. report an emission factor of 3.75 lb of CO_2 equiv/MMBtu for this stage of the LNG life-cycle by assuming that 3% of the gas is used to run the regasification equipment (*28*). The emission reported by Tamura et al. differs because they assumed only 0.15% of the gas is used to run the regasification terminal, while electricity, which may be generated with cleaner energy sources, provides the additional energy requirements. These values were used as lower and upper bounds of the range of emissions from regasification of LNG.

As done for the carbon emissions, natural gas produced in other countries and imported to the United States in the form of LNG is assumed to have the same SO_x and NO_x emissions in the production, processing, and transmission stages of the life-cycle as for natural gas produced in North America. Emission ranges for the liquefaction and regasification of natural gas were calculated using the AP 42 emission factors for reciprocating engines and natural gas turbines (*17*). It is assumed that 8.8% of natural gas is used in the liquefaction plant (*21*) and 3% is used in the regasification plants (*28*). Emissions of SO_x, and NO_x from transporting the LNG via tanker were calculated using the AP 42 emission factor for natural gas boilers and diesel boilers, as well as the tanker fuel consumption previously described.

3.3. Air Emissions from the Coal Life-Cycle. Greenhouse gas emissions from the mining life-cycle stage were developed from methane releases and from combustion of fuels used at the mines. EPA estimates that methane emissions from coal mines in 1997 were 75 million tons of CO_2 equivalents, of which 63 million tons came from underground mines and 12 million tons came from surface mines (*1*). CO_2 is also emitted from mines through the combustion of the fuels that provide the energy for operation. The U.S. Census Bureau provides fuel consumption data for mines in 1997 (*29*). These data are available in the Supporting Information. Fuel consumption data were converted to GHG emissions using the carbon content and heat content of each fuel and an oxidation fraction given in EPA's Inventory of U.S. Greenhouse Gas Emissions Sources and Sinks (*1*) (see Supporting Information). Emissions from the generation of the electricity consumed were calculated using an average 1997 emission factor of 1400 lb CO_2 equiv/MWh (*16*). These total emissions were then converted to an emission factor using the amount of coal produced in 1997 and the average heat content of this coal.

Emissions from the transportation of coal were calculated using the EIO-LCA tool developed at Carnegie Mellon University (*30*). To use this tool, economic values for coal transportation were needed. In 1997, the latest year for which the EIO-LCA tool has data, 84% of coal was transported via rail, 11% via barge, and 5% via truck. The cost for rail transport, barge, and truck transport was 13.9, 9.5, and 142.7 mills/ton-mile respectively (*12*). For a million ton-miles of coal transported, EIO-LCA estimates that 43.6 tons of CO_2 equivalents are emitted from rail transportation, 5.89 tons of CO_2 equivalents from water transportation, and 69 tons of CO_2 equivalents from truck transportation (*30*). These emissions were then converted to an emission factor by using the average travel distance of coal in each mode (796, 337, and 38 miles by rail, barge, and truck, respectively), the weighted average U.S. coal heat content of 10 520 Btu/lb (*31*) and the coal production data for 1997 (see Supporting Information).

The energy consumption data used to develop carbon emissions from the mining life-cycle stage were used to develop SO_x and NO_x emission factors for coal. AP 42 emissions factors for off-road vehicles, natural gas turbines, reciprocating engines, light duty gasoline trucks, large stationary diesel engines, and gasoline engines were used to develop this range of emission factors (*17*, *32*). In addition, the average emission factors from electricity generation in 1997 (3.92 lb NO_x/MWh and 7.86 lb SO_2/MWh (*16*)) were used to include the emissions from the electricity used in mines.

SO_x and NO_x emissions for coal transportation were again calculated using EIO-LCA (*30*). EIO-LCA estimates that a million ton-miles of coal transported via rail results in emissions of 0.02 tons of SO_x and 0.4 tons of NO_x. A million ton-miles of coal transported via water would emit 0.07 tons of SO_x, and 0.36 tons of NO_x. Finally, a million ton-miles of coal transported via truck would emit 0.06 tons of SO_x, and 1.42 tons of NO_x (*30*). These data were added to emissions from mines to find the total SO_x and NO_x emission factors for the upstream stages of the coal life-cycle.

3.4. Air Emissions from the SNG Life-Cycle. Performance characteristics for two SNG plants are given in the Supporting Information. These plants have a higher heating value efficiency between 57% and 60% (*33*, *34*). Using these efficiencies, emissions from coal mining, processing, and

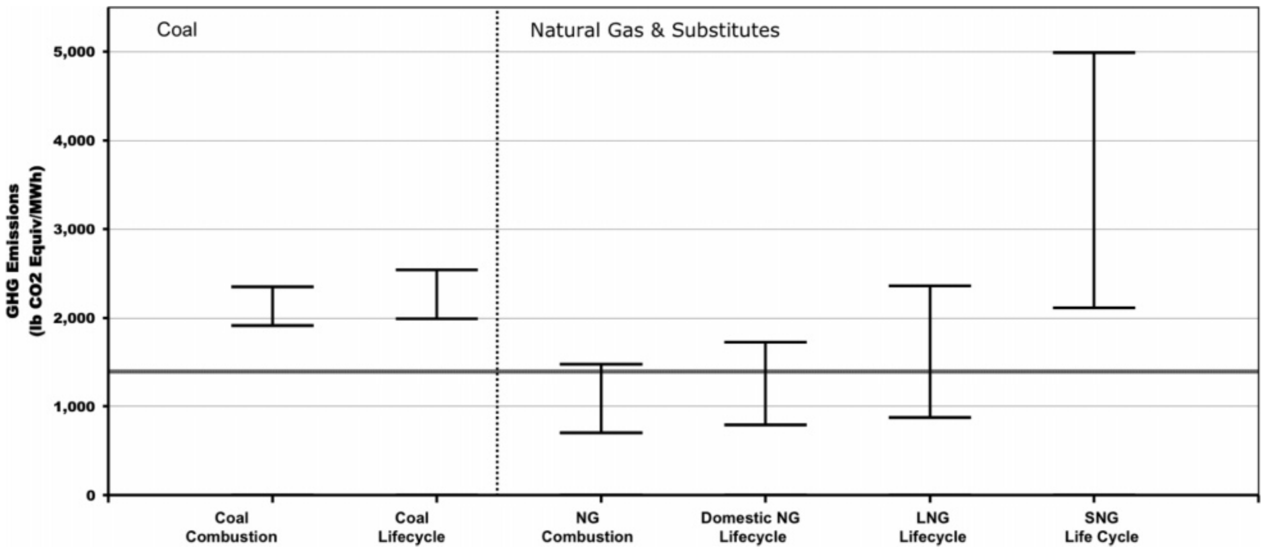

FIGURE 1. Fuel Combustion and Life-Cycle GHG Emissions for Current Power Plants.

transportation previously obtained were converted to pounds of CO_2 equiv/MMBtu of SNG. The data were also used to calculate the emissions at the gasification–methanation plant using a coal carbon content of 0.029 tons/MMBtu and a calculated SNG storage fraction of 37% (*1*). Finally, the emissions from transmission, storage, distribution, and combustion of SNG are the same as those for all other natural gas.

To develop the SO_x and NO_x emissions from the life-cycle of SNG, the emissions from coal mining and transport developed in the previous section in pounds per MMBtu of coal were converted to pounds per MMBtu of SNG using the efficiencies previously discussed. In addition, the emissions from natural gas transmission and storage were assumed to represent emissions from these life-cycle stages of SNG. The emissions from the gasification–methanation plant were taken from emission data for an Integrated Coal Gasification Combine Cycle (IGCC) plant, which operates with a similar process. Bergerson (*35*) reports SO_x emissions factors from IGCC between 0.023 and 0.15 lb/MMBtu coal (0.026–0.17 lb/MMBtu of coal if there is carbon capture), and a NO_x emission factor of 0.0226 lb/MMBtu coal (0.0228 lb/MMBtu of coal if there is carbon capture). These were converted to lb/MMBtu of SNG using the same coal-to-SNG efficiencies previously described.

4. Results

4.1. Comparing Fuel Life-Cycle Emissions for Fuels Used at Currently Operating Power Plants. Emission factors for the fuel life-cycles were calculated as pounds of pollutants per MMBtu of fuel produced, as presented in the Supporting Information. Since coal and natural gas power plants have different efficiencies, 1 MMBtu of coal does not generate the same amount of electricity as 1 MMBtu of natural gas/LNG/SNG. For this reason, emission factors given in Table 10S and Table 11S in the Supporting Information were converted to pounds of pollutant per MWh of electricity generated. This conversion is done using the efficiency of natural gas and coal power plants. According to the U.S. Department of Energy (DOE), currently operating coal power plants have efficiencies ranging from 30% to 37%, while currently operating natural gas power plants have efficiencies ranging from 28% to 58% (*36*). The life-cycle GHG emissions factors of natural gas, LNG, coal, and SNG described in the Supporting Information were converted to a lower and upper bound emission factor from coal and natural gas power plants using these efficiency ranges. Figure 1 shows the final bounds for the emission factors for each fuel cycle. The life-cycle for each fuel use includes fuel combustion at a power plant. The combustion-only emissions for each fuel are shown for comparison. The solid horizontal line shown represents the current average GHG emission factor for U.S. electricity generation: 1400 lb CO_2 equiv/MWh (*16*). Note that in this graph no carbon capture and storage (CCS) is performed at any stage of the life-cycle. CCS is a process by which carbon emissions are separated from other combustion products and injected into underground geologic formations such as saline formations or depleted oil/gas fields. A scenario in which CCS is performed at power plants as well as in gasification–methanation plants will be discussed in the following section.

It can be seen that combustion emissions from coal-fired power plants are higher than those from natural gas: the midpoint between the lower and upper bound emission factors for coal combustion is approximately 2100 lb CO_2 equiv/MWh, while the midpoint for natural gas combustions is approximately 1100 lb CO_2 equiv/MWh. This reflects the known environmental advantages from combustion of natural gas over coal. Figure 1 also shows that the life-cycle GHG emissions of electricity generated with coal are dominated by combustion, and adding the upstream life-cycle stages does not change the emission factor significantly, with the midpoint between the lower and upper bound life-cycle emission factors being 2270 lb CO_2 equiv/MWh. For natural-gas-fired power plants the emissions from the upstream stages of the natural gas life-cycle are more significant, especially if the natural gas used is synthetically produced from coal (SNG). The midpoint life-cycle emission factor for domestic natural gas is 1250 lb CO_2 equiv/MWh; for LNG and SNG it is 1600 lb CO_2 equiv/MWh and 3550 lb CO_2 equiv/MWh, respectively. SNG has much higher emission factors than the other fuels because of efficiency losses throughout the system. It is also interesting to note that the range of life-cycle GHG emissions of electricity generated with LNG is significantly closer to the range of emissions from coal than the life-cycle emissions of natural gas produced in North America. The upper bound life-cycle emission factor for LNG is 2400 lb CO_2 equiv/MWh, while the upper bound life-cycle emission factor for coal is 2550 lb CO_2 equiv/MWh.

To compare emissions of SO_x and NO_x from all life-cycles, the upstream emission factors and the power plant efficiencies from the Supporting Information are used. Emissions of these pollutants from coal and natural gas power plants in operation in 2003 were obtained from EGRID (*37*). Table 1

TABLE 1. SO_x and NO_x Combustion and Life-Cycle Emission Factors for Current Power Plants

fuel		SO_x (lb/MWh) min	SO_x (lb/MWh) max	NO_x (lb/MWh) min	NO_x (lb/MWh) max
current electricity mix		6.04		2.96	
coal	combustion	1.54	25.5	2.56	9.08
	life-cycle	1.60	25.8	2.83	9.69
natural gas	combustion	0.00	1.13	0.12	5.20
	life-cycle	0.04	1.49	0.17	9.40
LNG	life-cycle	0.094	2.93	0.25	15.4
SNG	life-cycle	0.30	3.88	0.65	8.08

shows life-cycle emissions for each fuel obtained by adding the combustion emissions from EGRID to the transformed upstream emissions. The current average SO_x and NO_x emission factors for electricity generated in the United States are also shown (*16*).

It can be seen that coal has significantly larger SO_x emissions than natural gas, LNG, or SNG. This is expected since the sulfur content of coal is much higher than the sulfur content of other fuels. SNG, which is produced from coal, does not have high sulfur emissions because the sulfur from coal must be removed before the methanation process.

For NO_x, it can be seen that the upstream stages of domestic natural gas, LNG, and even SNG make a significant contribution to the total life-cycle emissions. These upstream NO_x emissions come from the combustion of fuels used to run the natural gas system: for domestic natural gas, production is the largest contributor to these emissions; for LNG most NO_x upstream emissions come from the liquefaction plant; finally, for SNG most upstream NO_x emissions come from the gasification−methanation plant.

4.2. Comparing Fuel Life-Cycle Emissions for Fuels Used with Advanced Technologies. According to the DOE, by 2025 65 GW of inefficient facilities will be retired, while 347 GW of new capacity will be installed (*8*). Advanced pulverized coal (PC), integrated coal gasification combined cycle (IGCC), and natural gas combined cycle (NGCC) power plants could be installed. PC, IGCC, and NGCC plants are generally more efficient (average efficiencies of 39%, 38%, and 50%, respectively (*38*)) than the current fleet of power plants. In addition, CCS could be performed with these newer technologies. Experts believe that sequestration of 90% of the carbon will be technologically and economically feasible in the next 20 years (*5*, *38*). Having CCS at PC, IGCC, and NGCC plants decreases the efficiency of the plants to average of 30%, 33%, and 43%, respectively (*38*).

Figure 2 was developed using the revised efficiencies for advanced technologies and the GHG emission factors (in lb/MMBtu) described in the Supporting Information. This figure represents total life-cycle emissions for electricity generated with each fuel. Notice that emissions are shown with and without CCS. In the case of SNG with CCS, capture is performed at both the gasification−methanation plant and at the power plant. The solid horizontal line shown represents the current average GHG emission factor for electricity generation in the United States (1400 lb CO_2 equiv/MWh) (*16*). The upper and lower bound emissions in this figure are closer together than the upper and lower bounds in Figure 1, because only one power plant efficiency value is used, while for Figure 1 the upper and lower bound efficiency from all currently operating power plants was used (this is especially obvious for the domestic natural gas (NGCC) cases). It can be seen that, in general, life-cycle GHG emissions of electricity generated with the fuels without CCS would decrease slightly compared to emissions from current power plants that use the same fuel (due to efficiency gains). The most efficient natural gas plant currently in operation, however, could have slightly lower emissions than the lower bound for NGCC, LNGG, and SNGCC, due to efficiency differences. Three of the cases, however (PC, IGCC, and SNGCC), would still have higher emissions than the current average emissions from power plants. If CCS were used, however, there would be a significant reduction in emissions for all cases. In addition the midpoints between upper and lower bound emissions from all fuels are closer together, as can be seen in Figure 3. This figure also shows how the upstream from combustion emissions of fuels become significant contributors to the life-cycle emission factors when CCS is used.

Table 2 was developed using the upstream SO_x and NO_x emission factors obtained in this study and the combustion emissions reported by Bergerson (*35*) for PC and IGCC plants and by Rubin et al. for NGCC plants (*38*). These reported combustion emissions can be seen in the Table 12S in the Supporting Information.

As can be seen from Table 2, if advanced technologies are used there could be a significant reduction of NO_x and SO_x emissions, even if CCS is not available. It is interesting also to note that a PC plant with CCS could have lower life-cycle emissions than an IGCC plant with CCS. In the PC case all sulfur is removed through flue gas desulfurization. The removed sulfur compounds are then solidified and disposed of or sold as gypsum. In an IGCC plant with CCS, sulfur is removed from the syngas before combustion. In these plants, however, instead of solidifying the sulfur compounds removed and disposing them, the elemental sulfur is recovered in a process that generates some additional SO_x emissions (*35*). For NO_x, only LNG has higher life-cycle emissions than the average generated at current power plants.

5. Discussion

Natural gas is an important energy source for the residential, commercial, and industrial sectors. In the 1990s, the surge in demand by electricity generators and relatively constant natural gas production in North America caused prices to increase, so that in 2005 these sectors paid 58 billion dollars more than they would have paid if 2000 prices remained constant. Cumulative additional costs of higher natural gas prices for residential, commercial, and industrial consumers between 2000 and 2005 were calculated to be around 120 billion dollars. LNG has been identified as a source of natural gas that might help reduce prices, but even with an increasing supply of LNG, EIA still projects average delivered natural gas prices above $6.5/Mcf in the next 25 years. This is higher than the $4.5 /Mcf average projected price in earlier reports before the natural-gas-fired plant construction boom (*4*).

In addition to LNG, SNG has been proposed as an alternative source to add to the natural gas mix. The decision to follow the path of increased LNG imports or SNG production should be examined in light of more than just economic considerations. In this paper, we analyzed the effects of the additional air emissions from the LNG/SNG life-cycle on the overall emissions from electricity generation in the United States. We found that with current electricity generation technologies, natural gas life-cycle GHG emissions are generally lower than coal life-cycle emissions, even when increased LNG imports are included. However LNG imports decrease the difference between GHG emissions from coal and natural gas. SNG has higher life-cycle GHG emission than coal, domestic natural gas, or LNG. It is also important to note that upstream GHG emissions of NG/LNG/SNG have a higher impact in the total life-cycle emissions than upstream coal emissions. This is a significant point when considering a carbon-constrained future in which combustion emissions are reduced.

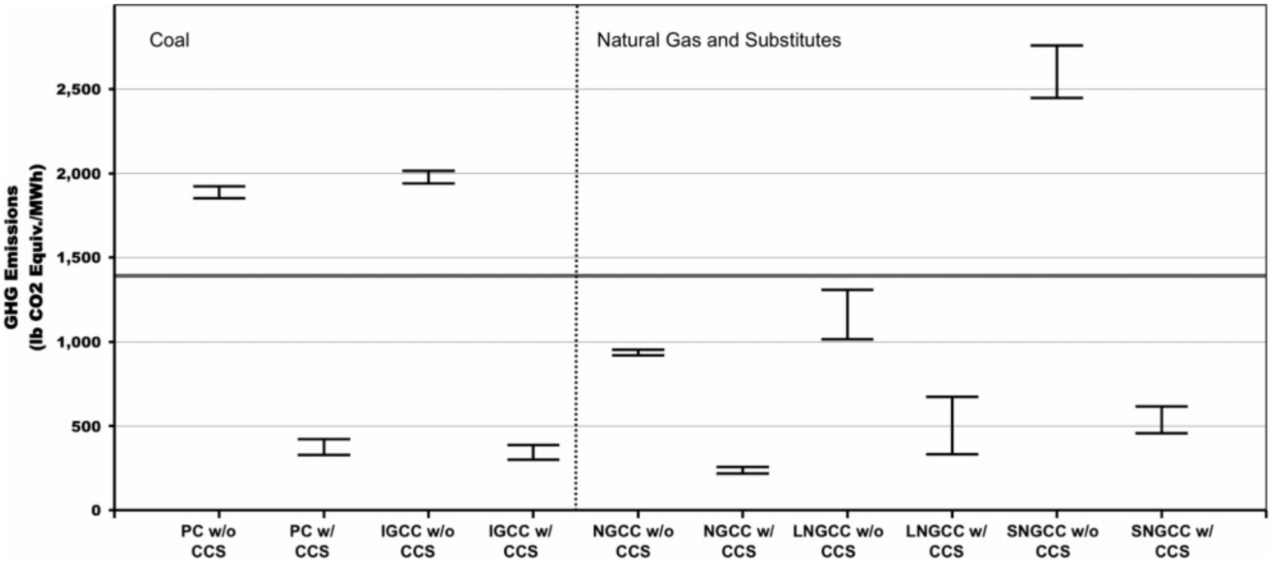

FIGURE 2. Fuel GHG Life-Cycle Emissions Using Advanced Technologies.

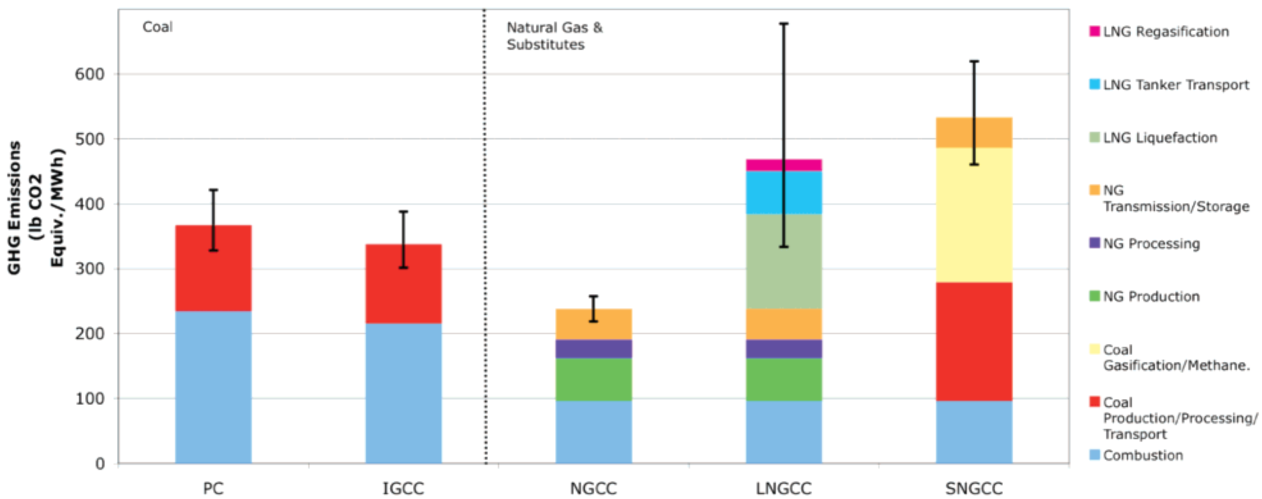

FIGURE 3. Midpoint Life-Cycle GHG Emissions Using Advanced Technologies with CCS.

TABLE 2. SO_x and NO_x Life-Cycle Emission Factors for Advanced Technologies

fuel		SO_x (lb/MWh) min	SO_x (lb/MWh) max	NO_x (lb/MWh) min	NO_x (lb/MWh) max
current electricity mix		6.04		2.96	
coal	PC w/o CCS	0.24	1.54	1.42	2.46
	PC w/ CCS	0.08	0.34	1.90	3.61
	IGCC w/o CCS	0.27	1.57	0.47	0.70
	IGCC w/ CCS	0.32	1.83	0.54	0.78
natural gas	NGCC w/o CCS	0.04	0.20	0.30	2.57
	NGCC w/ CCS	0.05	0.24	0.36	3.01
LNG	NGCC w/o CCS	0.25	1.04	0.39	5.89
	NGCC w/ CCS	0.30	1.23	0.46	6.91
SNG	NGCC w/o CCS	0.35	2.15	0.88	1.85
	NGCC w/ CCS	0.45	2.80	1.03	2.18

For emissions of SO_x, we found that with current electricity generation technologies, coal has significantly higher life-cycle emissions than any other fuel due to very high emissions at current power plants. For NO_x, however, this pattern is different. We find that with current electricity generation technologies, LNG could have the highest life-cycle NO_x emissions (since emissions from liquefaction and regasification are significant), and that even natural gas produced in North America could have life-cycle NO_x emissions very similar to those of coal. It is important to note that while GHG emissions contribute to a global problem, SO_x and NO_x are local pollutants and U.S. policy makers may not give much weight to emissions of these pollutants in other countries.

In the future, as newer generation technologies and CCS are installed, the overall life-cycle GHG emissions from electricity generated with coal, domestic natural gas, LNG, or SNG could be similar. Most important is that all fuels with advanced combustion technologies and CCS have lower life-cycle GHG emission factors than the current average emission factor from electricity generation. For SO_x we found that coal and SNG would have the largest life-cycle emissions, but all fuels have lower life-cycle SO_x emissions than the current average emissions from electricity generation. For NO_x, LNG would have the highest life-cycle emissions and would be the only fuel that could have higher emissions than the current average emission factor from electricity generation, even with advanced power plant design.

We suggest that advanced technologies are important and should be taken into account when examining the possibility of doing major investments in LNG or SNG infrastructure. Power generators hope that the price of natural gas will decrease as alternative sources of natural gas are added to the U.S. mix, so they can recover the investment made in natural gas plants that are currently producing well under capacity. We suggest that these investments should be viewed as sunk costs. Thus, it is important to re-evaluate whether investing billions of dollars in LNG/SNG infrastructure will lock us into an undesirable energy path that could make future energy decisions costlier than ever expected and increase the environmental burden from our energy infrastructure.

Acknowledgments

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Supporting Information Available

Graphical representation of the fuel life-cycles, emissions calculation information, summary of emissions from fuel life-cycles, power plant efficiency information, emissions from advanced technologies, and references, This material is available free of charge via the Internet at http://pubs.acs.org.

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Comparative Life-cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation

Supporting Information

1. Graphical Representation of the Fuel Life-cycles

Figure 1S and Figure 2S below, show the life-cycle stages on natural gas used by electric power generators, including the stages from the LNG life-cycle. Notice that local distribution of natural gas falls outside our analysis boundary.

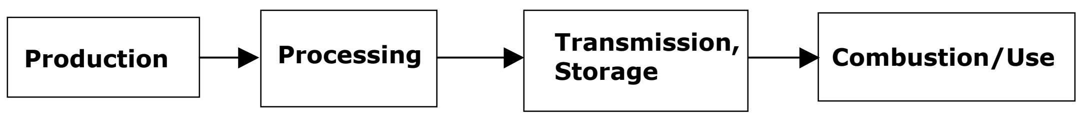

Figure 1S: Domestic Natural Gas Life-cycle.

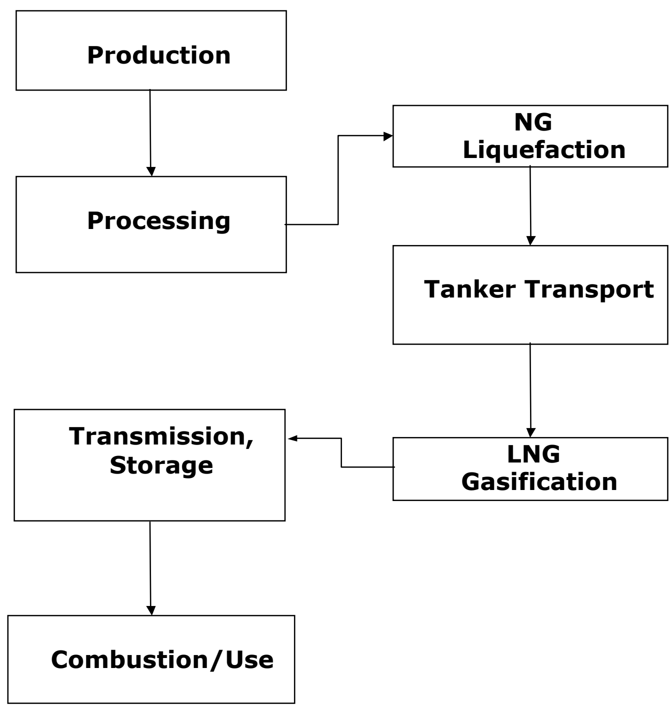

Figure 2S: LNG Life-cycle.

Figure 3S and Figure 4S show the life-cycle of coal and synthetic natural gas (SNG) derived from coal.

Figure 3S: Coal Life-cycle.

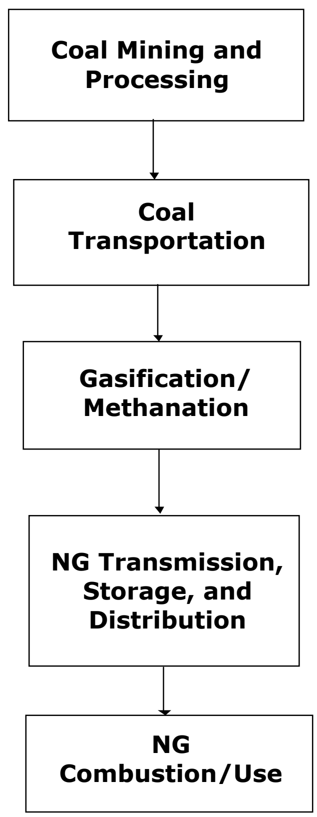

Figure 4S: SNG Life-cycle.

2. Calculating Emissions from the Domestic Natural Gas Life-cycle

During the late 1980s and early 1990s the U.S. Environmental Protection Agency (EPA) conducted a study to determine methane emissions from the natural gas industry (1). This comprehensive study developed hundreds of activity and emissions factors from all areas of the natural gas industry. These factors were developed using data collected from different sectors of the industry as well as from data collected in field measurements. Methane emissions from the U.S. natural gas system given as a percentage of natural gas produced can be seen in Table 1S. This data was used to develop methane emission factors, as described in the main document. Notice, that Table 1S includes an estimate for natural gas losses in the local distribution system. This estimate is given here for reference, but it was not included in our calculation of emissions of natural gas used to generate electricity.

In addition data from the EPA Natural Gas STAR program was used. The program is a voluntary partnership with the goal of encouraging the natural gas industry to adopt practices that increase efficiency and reduce emissions (for example by reducing natural gas leaks in the pipeline system). Consequently, since 1993, a cumulative total of 338 billion cubic feet of methane emissions have been eliminated. In 2003 alone, 52,900 million cubic feet of methane emissions were eliminated, a 9% reduction over projected emissions for that year without improved practices (2).

Table 1S: Methane Emissions from North American Gas Life-cycle as a Percentage of Natural Gas Produced (1).

Lifecycle Segment	Emissions as a Percentage of Gas Produced
Production	0.38%
Processing	0.16%
Transmission and Storage	0.53%
Distribution	0.35%

Carbon dioxide emissions from the different natural gas life-cycle stages were also calculated. These emissions were calculated using data on the amount of natural gas used to run the processes, as given in Table 2S, as well as an estimated 3 billion KWh of electricity used for pipeline transport. These data were also used to calculate SO_x and NO_x emissions from the life-cycle, as described in the main document. It should be mentioned that the pipeline fuel presented in Table 2S includes fuel used by the transmission system and the local distribution system. As previously described, natural gas used by electricity generators is bought directly from the transmission system, so that emissions from the distribution system are not included in our analysis. Due to data limitations, we were not able to disaggregate pipeline fuel and electricity consumption between the two systems. To deal with this issue, we use a range of emissions. The minimum value assumes that none of this fuel is consumed in the transmission system and the maximum value assumes that all is consumed in the transmission system.

Table 2S: Natural Gas Used During the Natural Gas Life-cycle. (3).

Use (as defined by EIA)	NG Life-cycle Stage	Amount (million ft^3)
Flared Gas	Production	98,000
Lease Fuel	Production	760,000
Pipeline Use	Transmission/Distribution	665,000
Plant Fuel	Processing	365,000

3. Calculating Emissions from the LNG Life-cycle

As mentioned in the main paper, Tamura et al (4) provide GHG emissions for liquefaction plants. Table 3S presents the sources of these emissions.

Table 3S: Liquefaction Emission Factors (Adapted from Tamura et al (4)).

Liquefaction	Emission Factors (lb CO_2 Equivalent/MMBtu)		
	Minimum	Average	Maximum
CO_2 from fuel combustion	11	12	13
CO_2 from flare combustion	0.00	0.77	1.5
CH_4 from vent	0.09	1.3	9.8
CO_2 in raw gas	0.09	4.0	6.6

Table 4S provides the distance from LNG exporting countries to two U.S. LNG terminals and the amount of LNG brought from each country in 2003. These two terminals were chosen because they are two of the largest terminals in the United States and they represent longest and shortest tanker travel distances for which route information is available. In addition, the range of distances provided is also representative of distances LNG would have to travel if a LNG terminal was located in the U.S. West Coast. Figure 5S shows the emission factors for LNG Tanker transport from each country to each of these terminals, obtained using the tanker information given in the main document. Emissions from tanker transport range between 2 and 17 pounds of CO_2 Equivalent per MMBtu of natural gas. These data was also used to calculate the SO_x and NO_x emission factors for tanker transport.

Table 4S: LNG Exporting Countries in 2003.

Exporting Country	Distance to Lake Charles Facility (nautical miles) (5)	Distance to Everett, MA Facility (nautical miles) (5)	2003 US Imports (million cubic feet NG) (3)
Algeria	5,000	3,300	53,000
Australia	12,000	11,000	0
Brunei	12,000	11,000	0
Indonesia	12,000	11,000	0
Malaysia	12,000	11,000	2,700
Nigeria	6,100	5,000	50,000
Oman	8,900	7,500	8,600
Qatar	9,700	8,000	14,000
Trinidad	2,200	2,000	380,000
UAE	9,600	7,959	0
Russia	9,600	11,000	0

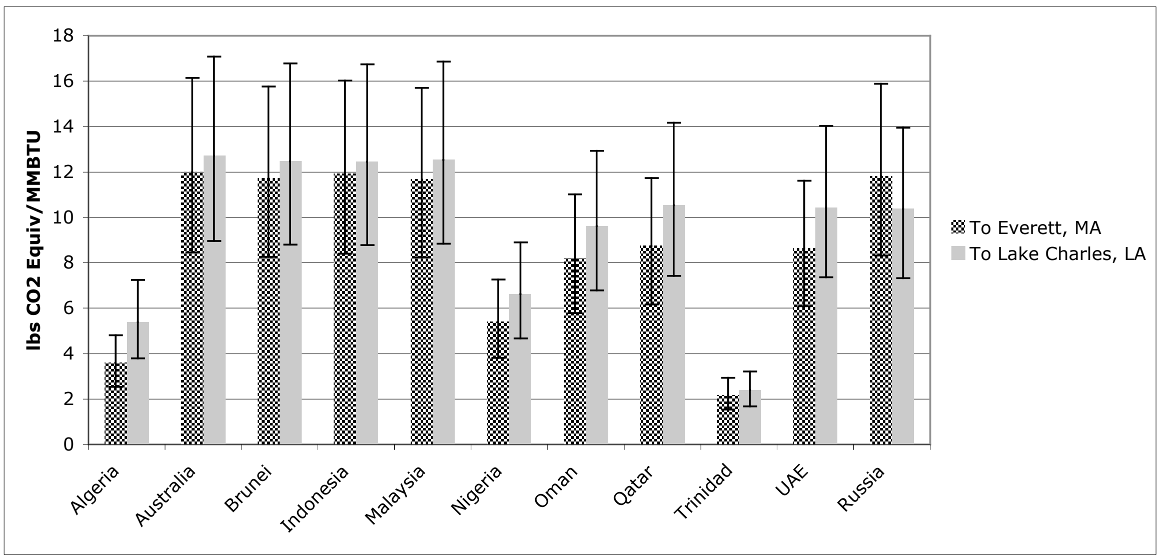

Figure 5S: Tanker Emission Factors from Each Country.

4. Calculating Emissions from the Coal Life-cycle

Table 5S presents fuel consumption data for coal mines in the U.S., and Table 6S presents carbon content, heat content of these fuels. These data was used to calculate GHG emissions factors for coal mines.

Table 5S: 1997 Fuel Consumption at Coal Mines (6)

Mine Type	Fuel Oil (1000 bbl)			Gas (10^9 ft^3)	Gasoline (10^6 gal)	Electricity (10^6 KWh)
	Total	Distillate	Residual			
Surface	8,280	7,524	756	0.7	30	42,474
Underground	801	656	145	0.5	4	7,123

Table 6S: Carbon Content, and Heat Content of Different Fuels (7).

Fuel Type	Carbon Content of Fuel lb/MMBtu Fuel	Heat Content of Fuel (MMBtu/bbl - MMBtu/MMcf)	Fraction Oxidized
Distillate	43.98	5.825	0.99
Residual	47.38	6.287	0.99
Gas	31.90	1,030	0.995
Gasoline	42.66	5.253	0.99

Table 7S: 1997 Coal Production Data (8).

Mine Type	Coal Produced (1000 tons)	Heat Content of Coal (BTU/lb)
Surface	669,273	9,626
Underground	420,657	11,944
Total	1,089,930	10,520

As described in the main document, EIO-LCA was used to estimate emission factors from coal transportation. Table 8S summarizes the emissions resulting from transporting one million ton-miles of coal via each transportation mode.

Table 8S: EIO-LCA GHG Emission Data for a Million Ton-Miles of Coal Transported (9).

Sector	Total GHG Emissions (tons CO_2 Equivalent)	Total SO_x Emissions (tons SO_x)	Total NO_x Emissions (tons NO_x)
Rail Transportation	43.6	0.02	0.40
Water Transportation	5.89	0.07	0.36
Truck Transportation	69.0	0.06	1.42

5. Calculating Emissions from the SNG Life-cycle

In order to calculate air emissions from the SNG life-cycle, the emissions from coal production, processing and transport were converted from pounds per MMBtu of coal used to pounds per MMBtu of SNG produced using the performance characteristics of two SNG plants given in Table 9S. The emissions from SNG transport, storage and use are the same as those from natural gas. The efficiency for the CCS case was obtained assuming an energy penalty of 16% as described for and IGCC plant by Rubin et al (10).

Table 9S: SNG Plant Performance Characteristics

	Case 1 (11)	Case 2 (12)
SNG Output (1. mcf/day and 2. MMBtu/hr)	250	1,739
Efficiency without CCS (HHV)	57%	60%
Efficiency with CCS (HHV)	50%	52%

6. Summary of Emissions from Fuel Life-cycles

Table 10S summarizes GHG emission factors for all fuels. The emission factors presented in this section are the average emission rate relative to units of fuel produced, without considering the efficiency of using these fuels. These emission factors can later be used to develop total inventories of GHG emissions from the annual consumption of each fuel. Allocation of these emissions for each life-cycle stage can be seen in Figure 6S through Figure 8S. Note that there are two different emission factors for SNG. In one case, no carbon capture and sequestration (CCS) is performed at the gasification-methanation stage. When CCS is performed at the gasification-methanation plant, an energy penalty is incurred. It was assumed that the energy penalty observed at IGCC plants with CCS (16%) is representative of the energy penalty at the SNG gasification-methanation plant (10). CCS could also be performed at power plants, as discussed in the main document.

It is also very important to note that the emission factors shown in Table 10**S** (and the emission factors given in Table 11S) are not comparable to each other, since one Btu of coal does not generate the same amount of electricity as one Btu of natural gas or SNG. These emission factors can be transformed to comparable units, namely lbs/MWh of electricity produced, by taking into consideration the efficiency of electricity generation.

Table 10S: Life-cycle GHG Emission Factors

(units: lbs/MMBtu of Fuel Produced)

Life-cycle Stages	North American NG		LNG		Coal		SNG (No CCS at Gasif./Methan. Plant)		SNG (CCS at Gasif./Methan. Plant)	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
Upstream	15.3	20.1	29.6	72.3	8.2	16.4	240	286	45.2	65.2
Combustion (no CCS)	120	120	120	120	205	205	120	120	120	120
Combustion (with CCS)	12	12	12	12	20.5	20.5	12	12	12	12

SO_x and NO_x emission factors for the upstream stages of electricity generation for the fuel life-cycles can be seen in Table 11S. SO_x and NO_x emissions from the combustion of fuel at power plants are very dependent on specific plant characteristics, so it was not possible to transform these power plant emissions (given in lbs/MWh) to the same units as the emissions from the upstream stages of the life-cycle (lbs/MMBtu) by simply using the efficiency of the power plants.

Table 11S: Upstream SO_x and NO_x Emission Factors (units: lbs/MMBtu of Fuel Produced)

Pollutant	North American Natural Gas		LNG		Coal		SNG (No CCS at Gasif./Methan. Plant)		SNG (CCS at Gasif./Methan. Plant)	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
SO_x	0.006	0.030	0.016	0.145	0.007	0.029	0.051	0.316	0.064	0.400
NO_x	0.009	0.342	0.022	0.831	0.030	0.535	0.090	0.234	0.104	0.253

7. GHG Emissions Allocated to Fuel Life-cycle Stages

Figure 6S through Figure 8S show how the GHG emissions reported in Table 10S are allocated among the different life-cycle stages.

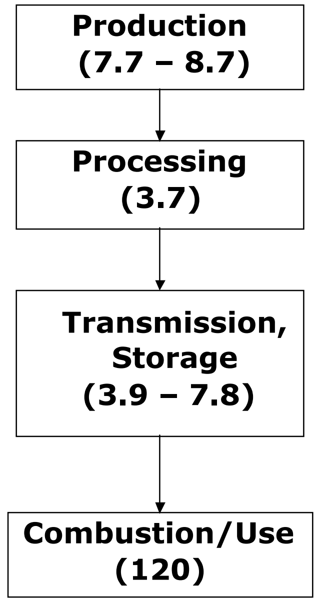

Figure 6S: North American Gas Life-cycle GHG Emission Factors (Units: lbs CO_2 Equivalent/MMBtu).

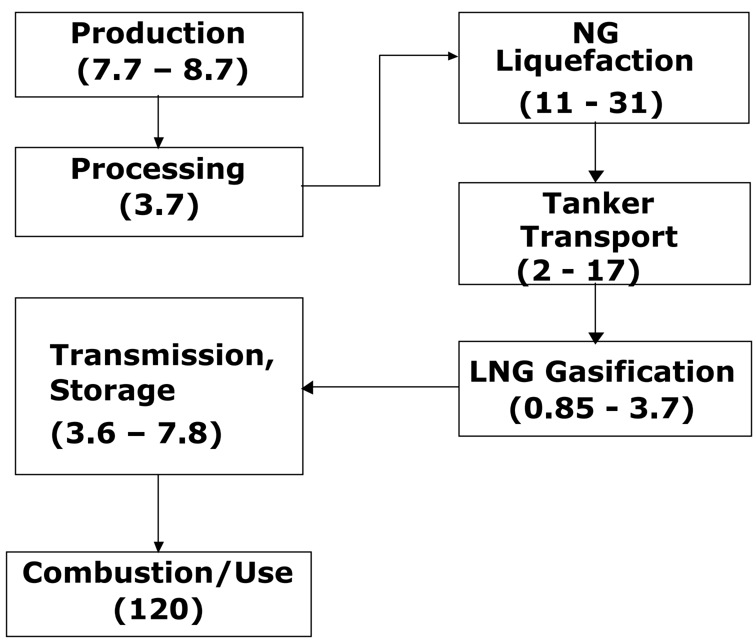

Figure 7S: LNG Life-cycle GHG Emission Factors (Units: lbs CO_2 Equivalent/MMBtu).

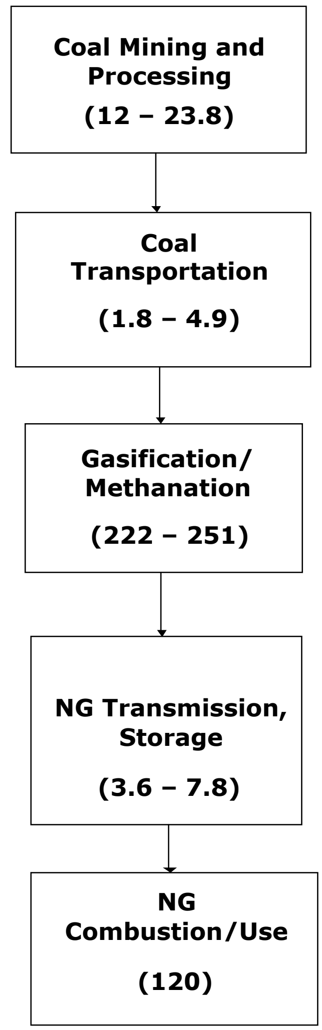

Figure 8S: SNG Life-cycle GHG Emission Factors (Units: lbs CO_2 Equivalent/MMBtu).

8. Efficiencies of Currently Operating Power Plants

Figure 9S shows the distribution of the efficiencies of currently operating power plants, obtained using the cumulative distribution function of EIA 2003 electricity generation data for all utility plants (13). As illustrated in Figure 9S, the median efficiency for natural gas plants is higher than the median efficiency for coal plants. These efficiencies were used to convert the emission factors previously presented (in lbs/ MMBtu of fuel) to lbs/MWh.

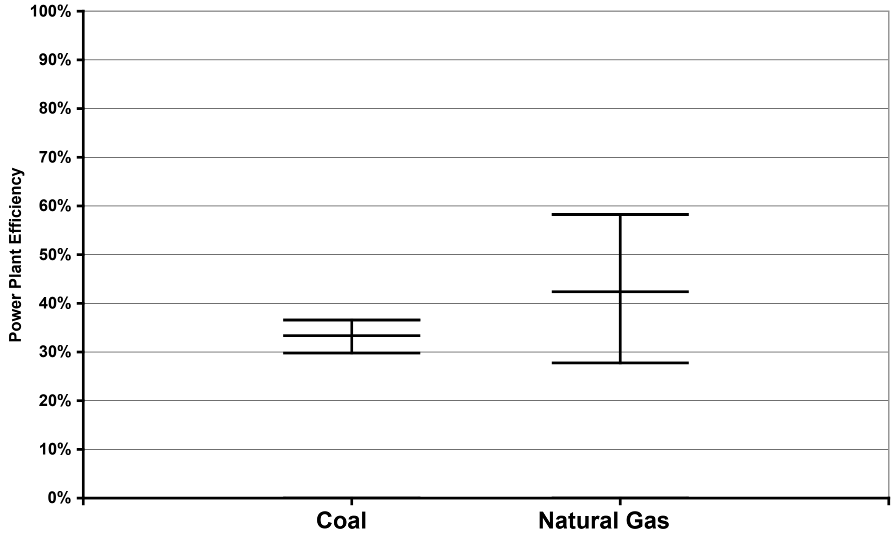

Figure 9S: Efficiencies of Natural Gas and Coal Plants (13).

9. Combustion Emissions from Advance Technologies

Table 12S reports combustion emissions from advanced power plant technologies. The emission factors from PC and IGCC plants were reported Bergerson (14) for PC and IGCC plants. Rubin et al reported the emissions for NGCC plants (10).

Table 12S: Combustion Emissions from Advanced Power Plants.

Fuel/Pollutant	SO_x (lbs/MWh)		NO_x (lbs/MWh)	
	Min	Max	Min	Max
PC w/o CCS	0.17	1.28	1.16	2.00
PC w/ CCS	0.00	0.01	1.56	3.00
IGCC w/o CCS	0.20	1.30	0.20	0.20
IGCC w/ CCS	0.24	1.52	0.20	0.20
NGCC w/o CCS	0.00	0.00	0.24	0.24
NGCC w/ CCS	0.00	0.00	0.29	0.29

10. References

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Comparative Life Cycle Carbon Emissions of LNG Versus Coal and Gas for Electricity Generation

Paulina Jaramillo, W. Michael Griffin, H. Scott Matthews

Introduction

Natural gas currently provides 24% of the energy used by homes and businesses in the US (1). It is also an important feedstock for the chemical and fertilizer industry. In the early 1990's the price of natural gas was low (around \$3/1000 ft^3) and as a result there was a surge in construction of natural gas plants (2). Today, the Henry Hub price of natural gas is around \$15/1000 ft^3 (3), and most of these plants are operating below capacity. However, natural gas consumption is expected to increase 41% by 2025 (to 30 trillion cubic feet), with demand from electricity generators growing the fastest (increasing 90% by 2025). At the same time natural gas production in North America is expected to remain fairly constant at around 24 trillion cubic feet, so that demand of imported liquefied natural gas (LNG) will increase to around 6 trillion cubic feet or 20% of the total supply by 2025 (3).

The natural gas system is the second largest source of greenhouse gas emissions in the US, generating around 132 million tons of CO_2 Equivalents (1). Several studies have performed emission inventories for the natural gas lifecycle from production to distribution. Usually these analyses have been performed for domestic natural gas, so that emissions from the LNG lifecycle stages have been ignored. If, as the DOE estimates suggest, larger percentages of the supply of natural gas will come from these imports, emissions from these steps in the lifecycle could influence the total natural gas lifecycle emissions. Thus, comparisons between coal and natural gas that concentrate only on the emissions at the utility plant may not be adequate. The objective of this study is to perform an analysis of the natural gas lifecycle greenhouse gas emissions taking the emissions from LNG into consideration. Different scenarios for the percentage of natural gas as LNG are analyzed. Moreover, a comparison with the coal fuel cycle greenhouse gas emissions will be presented, in order to have a better understanding of the advantages and disadvantages of using coal versus natural gas for electricity generation.

The Natural Gas Life Cycle

The natural gas life cycle starts with the production of natural gas and ends at the combustion plant. NaturalGas.org has a very detailed description of this life cycle. Readers are encouraged to visit this website if they need more information about the topic.

Geological surveys and seismic studies are used to determine the location of natural gas deposits. After these sites have been identified, wells are constructed. There are two types of well for the extraction of natural gas: oil wells and natural gas wells. Oil wells are drilled primarily to extract oil, but natural gas can also be obtained. Natural gas wells are specifically drilled to extract natural gas.

After natural gas is extracted through the wells, it has to be processed to meet the characteristics of the natural gas used by consumers. Consumer natural gas is composed primarily of methane. However, when natural gas is extracted, it exists with other hydrocarbons such as propane and ethane. In addition, the extracted natural gas contains impurities such as water vapor and carbon dioxide that must be removed. Natural gas processing plants are usually constructed in gas producing regions. The natural gas is transported from the extraction sites to these plants through a system of low-diameter, low-pressure pipelines. At the plant, water vapor is first removed from the gas by using absorption or adsorption methods. Glycol Dehydration is an example of absorption, in which glycol, which has a chemical affinity to water, is used to absorb the vapor. Solid-Desiccant Dehydration is an example of adsorption. In this process the natural gas passes through towers that contain activated alumina or other solid desiccants. As the gas is passed through these towers, the water particles are retained on the surface of the solids.

As previously mentioned, natural gas is extracted with other hydrocarbons that must be removed. The removal of these hydrocarbons, called Natural Gas Liquids (NGL), is done with the absorption method or the cryogenic expander process. The absorption method is similar to the water absorption method, but instead of glycol, absorbing oil is used. The cryogenic expansion method consists of dropping the temperatures of the gas causing the hydrocarbons to condense so that they can be separated from the natural gas. The absorption method is used to remove heavier hydrocarbons, while lighter hydrocarbons are removed using the cryogenic expansion process.

The final step in the processing of natural gas is the removal of sulfur and carbon dioxide. Often, natural gas from the wells contains high amounts of these two compounds, and it is called sour gas. Sulfur must be removed from the gas because it is a potentially lethal chemical if breathed. In addition, sour gas can be corrosive for the transmissions and distribution pipelines. The process of removing sulfur and carbon dioxide from the gas is similar to the absorption processes previously described.

After the natural gas is processed it enters the transmission system. In the US, this transmission system is the interstate natural gas pipeline network, which consists of thousands of miles of high-pressure pipelines that transport the gas from producing areas to high demand areas. In addition to the pipes, this pipeline system has compressor stations along the way, usually placed in 40 to 100 mile intervals. These compressor stations use a turbine or an engine to compress the natural gas and maintain the high pressure required in the pipeline. The turbines and engines generally run with a small amount of the gas from the pipeline. In addition to compressor stations, metering stations are also placed along the system to allow companies to better monitor and manage the natural gas in the pipes. Moreover valves can be found through the entire length of the pipelines to regulate flow.

Natural gas can be stored to meet seasonal demand increases or to meet sudden, short-term demand increases. Natural gas is usually stored in underground facilities. Such facilities could be built in reconditioned depleted gas reservoirs, aquifers or salt caverns. According to the Energy Information Administration (EIA), in 2003 the total storage capacity in the United States was 8.2 billion cubic feet. 82% of this capacity was in depleted gas fields, 15% in depleted aquifers, and 3% in salt caverns. Moreover during that year, withdrawals from storage added to 3.1 billion cubic feet while injections totaled 3.3 billion cubic feet (4). It is important to note that some gas injected into underground storage becomes physically unrecoverable gas. This gas is known as base gas.

Distribution is the final step before natural gas is delivered to consumers. Local Distribution Companies transport natural gas from delivery points along the transmission system to local consumers via a low-pressure, small-diameter pipeline system. Natural gas that arrives to a city gate through the transmission system is depressurized, and filtered to remove any moisture or particulate content. In addition, Mercaptan is added to the gas to create the distinctive smell that allows leaks to be detected. Small compressors are used in the distribution system to maintain the pressure required.

When Liquefied Natural Gas (LNG) is added to the mix of natural gas, three additional lifecycle stages are created: liquefaction, tanker transport, and regasification. Figure 1 shows the total life cycle of natural gas including the LNG stages.

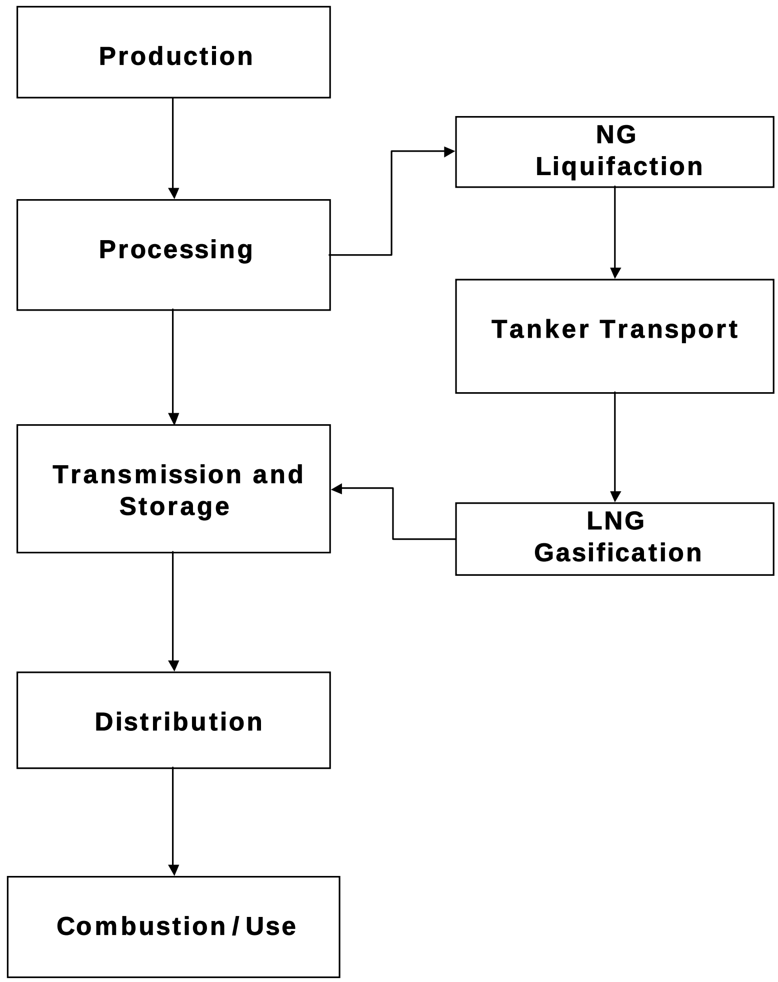

Figure 1: Natural Gas Life Cycle Including LNG.

In the liquefaction process, natural gas is cooled and pressurized to convert it to liquid form, reducing its volume by a factor of 610 (5). These liquefaction plants are generally located in coastal areas of LNG export countries. Currently 75% of the LNG imported to the US comes from Trinidad, but this percentage is expected to decrease as more imports come from Russia, the middle east, and southeast Asia (4). LNG tankers bring this gas to the US. According to EIA, there were 151 LNG tankers in operation worldwide as of October 2003. The majority of these tankers have the capacity to carry more than 120,000 cubic meters of liquefied natural gas (equivalent to 2.59 billion cubic feet of natural gas, enough gas to supply an average of 31,500 residences for a year (4)) and the total fleet capacity is 17.4 million cubic meters of liquid (equivalent to 366 billion cubic feet of natural gas). There are currently fifty-five ships under construction that will increase total fleet capacity to 25.1 million cubic meters of liquid (equivalent to 527 billion cubic feet of natural gas) in 2006 (6).

Regasification facilities are the last step LNG must pass through before going into the US pipeline system. Regasification facilities are LNG marine terminals where LNG tankers unload their gas. These facilities consist of storage tanks and vaporization equipment that warms the LNG to return it to the gaseous state. There are currently 5 LNG terminals in operation in the US: Lake Charles, Louisiana; Elba Island, Georgia; Cove Point, Maryland; Everett, Massachusetts; and a recently opened offshore terminal in the Gulf of Mexico. These terminals have a combined base load capacity of 3.05 billion cubic feet per day (about 1 trillion cubic feet per year). In addition to these there are over fifty proposed facilities for a total proposed capacity of 62 billion cubic feet per day (23 trillion cubic feet per year). Figure 2 shows the proposed location of these facilities (6).

As shown in Figure 1, natural gas combustion is the last stage in the natural gas lifecycle. In the US, natural gas is used for electricity generation, heating, and several industrial processes. Approximately 24% of the electricity generated comes from natural gas (1). Natural gas plants have heat rates that range from 5,800 BTU/kWh to 12,300 BTU/kWh (7).

US Natural Gas Industry in 2003

In 2003, the total supply of natural gas in the US was over 27 trillion cubic feet. Of this, 26.5 trillion cubic feet were produced in North America (US, Canada, and Mexico), and 0.5 trillion cubic feet were imported in the form of LNG. 75% of LNG came from Trinidad and Tobago. Other exporting countries included Algeria, Malaysia, Nigeria, Qatar, and Oman (4). Table 1 shows more detailed statistics about the state of the US natural gas industry in 2003. Numbers may not add up due to rounding.

Table 1: 2003 Natural Gas Industry Statistics (All units in million cubic feet) (4)

Gross Withdrawals	24,000,000
Total Dry Production	19,000,000
Total Supply	27,000,000
Total Consumption	22,500,000
Total Imports	4,000,000
Pipeline Imports	3,500,000
LNG Imports	505,000

Greenhouse gas emissions from Natural Gas produced in North America

During the late 1980's and early 1990's the US Environmental Protection Agency (EPA) conducted a study to determine methane emissions from the natural gas industry. This very comprehensive study developed hundreds of activity and emissions factors from all the areas of the natural industry. These factors were developed using data collected from the different sectors of the industry as well as from data collected in field measurements. Table 2 presents the percentage of produced natural gas that is emitted to the atmosphere during the lifecycle according to the results of the previously described study, as well as the source of these emissions.

Table 2: Methane Emissions from North American Gas Life Cycle as a Percentage of Natural Gas Produced (8).

Lifecycle Segment	Emission Sources	Emissions as a Percentage of Gas Produced
Production	Pneumatic Devices	0.38%
	Fugitive Emissions	
	Underground Pipeline Leaks	
	Blow and Purge	
	Compressor	
	Glycol Dehydrator	
Processing	Fugitive Emissions	0.16%
	Compressor	
	Blow and Purge	
Transmission and Storage	Fugitive Emissions	0.53%
	Blow and Purge	
	Pneumatic Devices	
	Compressor	
Distribution	Underground Pipeline Leaks	0.35%
	Meter and Pressure Stations	
	Costumer Meter	

Based on the statistics presented in Table 1, 26.5 billion cubic feet of natural gas were produced in North America in 2003. Using the percentages of natural gas emitted, an average heat content of 1,030 BTU/ft^3, and the assumption that 100% of the natural gas lost is methane (density 19.23 gr/ ft^3) which may result in a slight overestimate of emissions given that the real percentage of methane in natural gas varies between 94% and 98%; total methane emission were calculated to develop the emission factors shown in Figure 4.

In addition to methane, carbon dioxide emissions are produced from the combustion of natural gas used during the lifecycle stages previously described. The Energy Information Administration maintains records of the amount of natural gas used during the production, processing, transmission, storage, and distribution of natural gas. This data for 2003 can be seen in Table 3. Assuming that 100% of this gas is methane, total carbon dioxide emissions were found using thermodynamic calculations. These emissions were then added to methane emissions to obtain the total emission factors shown in Figure 3.

Table 3: Natural Gas Used During Natural Gas Life Cycle. (All units in million cubic feet) (4).

Flared Gas	98,000
Lease Fuel	760,000
Pipeline and Distribution Use	665,000
Plant Fuel	365,000

In 1993 the Natural Gas STAR program was established by the EPA to reduce methane emissions from the natural gas industry. The program is a voluntary partnership with the goal of encouraging industries to adopt practices that increase efficiency and reduce emissions. Since 1993, 338 billion cubic feet of methane have been eliminated. In 2003, 52,900 million cubic feet of methane emissions were eliminated, a 9% reduction over projected emissions for that year without improved practices (9). This data was used to develop a range of emission factors for the North American natural gas industry. Figure 2 shows the total range of emission factors for the North American natural gas lifecycle. It can be seen that total lifecycle emission for natural gas produced in North America are approximately 140 lbs CO_2/MMBTU, an amount dominated by combustion emissions for natural gas plants currently in operation in the US of an average 120 lbs CO_2/MMBTU (10)

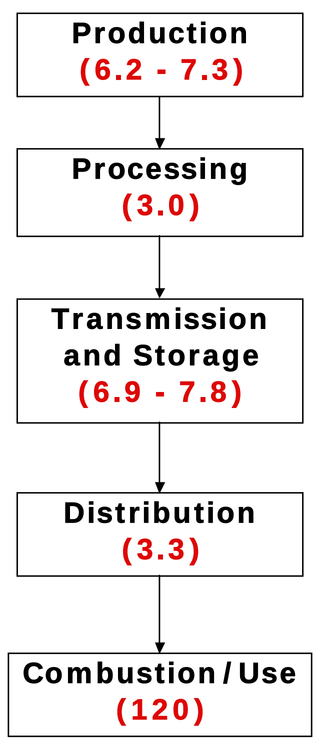

Figure 2: Carbon Dioxide Equivalent Emission Factors from North American Gas Lifecycle (All Units in lbs CO_2/MMBTU).

Greenhouse gas emissions from LNG lifecycle

As shown in Figure 1, the addition of liquefied natural gas (LNG) into the North American gas system introduces three additional stages into the lifecycle of natural gas: liquefaction, tanker transport, and regasification. It is assumed that natural gas produced in other countries and imported to the US in the form of LNG produces the same emissions in the production, processing, transmission, and distribution stages of the lifecycle as if the natural gas were produced in North America. Additional emission factors needed to be developed for the three additional lifecycle stages of LNG. Tamura et-al (11) has reported emission factors for the liquefaction stage in the range of 1.32 to 3,67 gr-C/MJ. Using these results, the emission factors for liquefaction were found in units of pounds of CO_2 per million BTUs, as shown in Table 4.

Table 4: Liquefaction Emission Factors.

Liquefaction	**Emission Factors (lb CO_2/MMBTU)**		
	Min	**Average**	**Max**
CO_2 from fuel combustion	11	12	13
CO_2 from flare combustion	0.00	0.77	1.5
CH_4 from vent	0.09	1.3	9.8
CO_2 in raw gas	0.09	4.0	6.6

Emissions from tanker transport of LNG were calculated using Equation 1.

$$EmissionFactor = \frac{(EF)\sum_{x}\left[\left(2 \times roundup\left(\frac{LNG_x}{TC}\right)\right) \times \frac{D_x}{TS} \times FC \times \frac{1}{24}\right]}{LNG_T}$$

Equation 1: Tanker Emission Factor.

Where EF is the tanker emission factor of 3,200 kg CO_2/ ton of fuel consumed; 2 is the number of trips each tanker does for every load (one bringing the LNG and one going back empty); LNG_x is the amount of natural gas (in cubic feet) brought from each country; TC is the tanker capacity in cubic feet of natural gas, assumed to be 120,000 cubic meters of LNG (1 m^3 LNG = 21,537 ft^3 NG); Dx is the distance from each country to US LNG facilities; TS is the tanker speed of 14 Knots; FC is a fuel consumption of 41 tons of fuel per day; and 24 is hours per day (12).

Exporting countries, their distances to the LNG facilities at Lake Charles, LA and Everett, MA, and the 2003 US imports can be seen in Table 5.

Table 5: LNG Exporting Countries in 2003 (4).

Exporting Country	Distance to Lake Charles Facility (nautical miles)	Distance to Everett, MA Facility (nautical miles)	2003 US Imports (million cubic feet NG)
Algeria	5,000	3,300	53,000
Australia	12,000	11,000	0
Brunei	12,000	11,000	0
Indonesia	12,000	11,000	0
Malaysia	12,000	11,000	2,700
Nigeria	6,100	5,000	50,000
Oman	8,900	7,500	8,600
Qatar	9,700	8,000	14,000
Trinidad	2,200	2,000	380,000
UAE	9,600	7,959	0
Russia	9,600	11,000	0

Emission factors for tanker transport from each country to both US facilities can be seen in Figure 3.

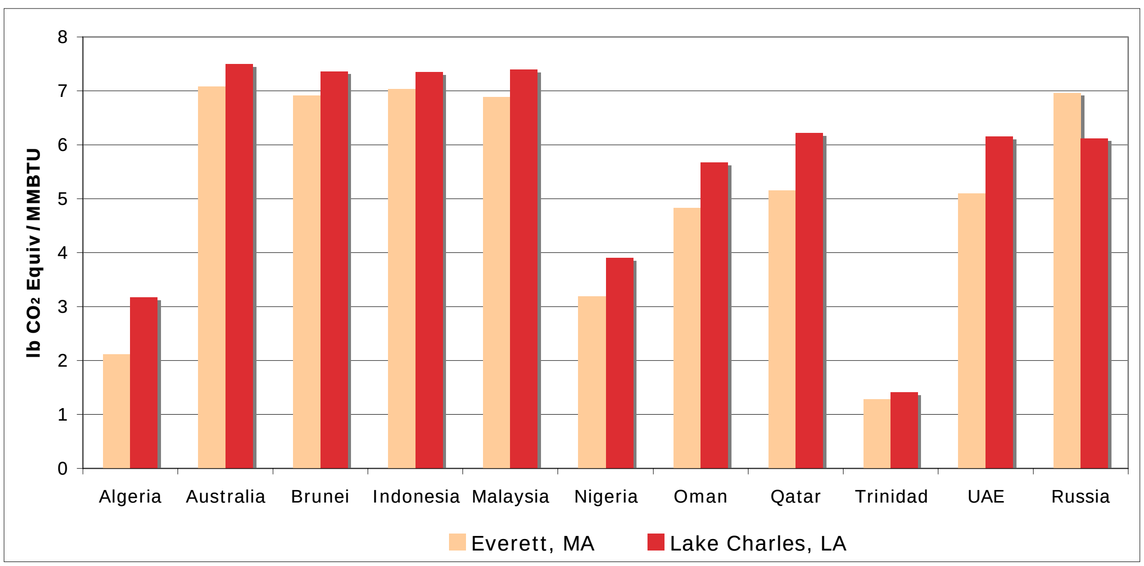

Figure 3: Tanker Emission Factors from Each Country

Since most of the LNG in 2003 was brought from Trinidad, the weighted average emission factor calculated for trips from each country to the Everett, MA facility is considered to be the a lower bound. An upper bound was obtained by assuming that all LNG was brought from Indonesia to the Lake Charles facility, and an average was obtained assuming all LNG was brought from Oman to the Lake Charles, LA facility. These resulting numbers can be seen in Table 6.

Table 6: Tanker Transport Emission Factors.

Emission Factors (lb CO_2/MMBTU)	
Min	1.8
Average	5.7
Max	7.3

Regasification emissions were reported by Tamura et-al to be 0.1 gr C/ MJ (0.85 lb CO_2/MMBTU) (11). Ruether et-al reports an emission factor of 1.6 gr CO_2/MJ (3.75 lb CO_2/MMBTU) for this stage of the LNG lifecycle by assuming that 3% of the gas is used to run the regasification equipment (13). These values were used as the lower and upper bounds of the range of emission from regasification of LNG. Total LNG lifecycle emissions are shown in Figure 4. They range between 154 and 184 lbs CO_2/MMBTU

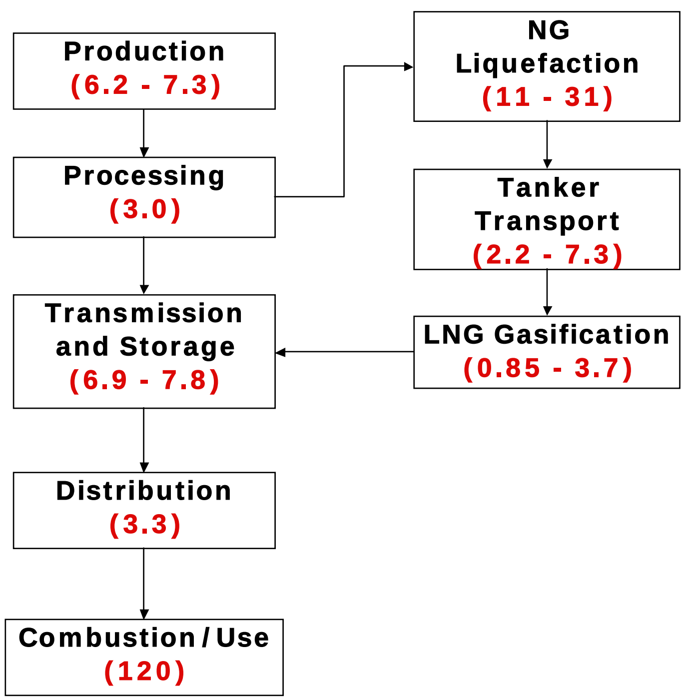

Figure 4: LNG Lifecycle Emission Factors (All Units in lbs CO_2/MMBTU).

Coal Lifecycle and its Greenhouse Gas Emissions for Electricity Generation

The coal lifecycle is conceptually simpler than the natural gas lifecycle, consisting of only three steps, as shown in Figure 5.

Figure 5: Coal Lifecycle.

In the US, 67% of the coal produced is mined in surface mines, while the remaining 33% is extracted from underground mines (1). Mined coal is then processed to remove impurities. Coal is then transported from the mines to the consumers via rail (84%), barge (11%), and trucks (5%) (14). Emissions from these lifecycle steps were calculated using the EIO-LCA tool developed at Carnegie Mellon University. In order to use this tool, economic values for each step of the lifecycle were necessary. In 1997, the year for which the EIO-LCA tool has data, the price of coal was $18.14/ton (15). Moreover, the cost for rail transport, barge, and truck transport was $11.06/ton, $3.2/ton, and $5.47/ton respectively (14). For a million tons of coal the following emission information was obtained using EIO-LCA.

Table 7: EIO-LCA Emission Data for Coal Lifecycle (16).

Sector	Total GHG Emissions (MT CO_2 Equiv)
Mining	75,000
Rail Transportation	36,000
Water Transportation	3,700
Truck Transportation	5,000

Using a weighted average US coal heat content of 10,266 BTU/lb (17) and the data previously discussed, it was found that the average emission factor for coal mining and transport is 11 lb CO_2/MMBTU.

In 1999, the National Renewable Energy Lab published a report on lifecycle emissions for power generation from coal (18). Upstream coal emissions (including transportation) from underground mines are reported to be 15 lbs CO_2/MMBTU, while upstream coal emissions from surface mines is 9.9 lbs CO_2/MMBTU. As previously mentioned, 67% of coal is currently mines in surface mines, while 33% is mined in underground mines (1). Using this information, the current coal upstream emissions average 12 lbs CO_2/MMBTU, which is very close to the emission factor obtained using EIO-LCA. In the future, the distribution of US mines could change, affecting the average emission factor. For this reason, the range of coal upstream emissions from underground and surface mines described above is used for this paper. Moreover, the average emission factors for coal combustion at utility plants used is 205 lb CO_2/MMBTU (10).

Comparing Natural Gas and Coal Lifecycle Emissions

Emissions factors for the natural gas lifecycle and the coal lifecycle were previously reported in pounds of CO_2 per MMBTU of fuel. Coal and natural gas power plants have different efficiencies; thus one million BTU of coal does not generate the same amount of electricity as one million BTU of natural gas. For this reason, emission factors must be converted to units of pounds of CO_2 per kWh of electricity generated. This conversion was done using the heat rates of natural gas and coal plants. Figure 6 shows the distribution of these heat rates, and Figure 7 shows the resulting emission factor distribution for coal and natural gas. These distributions were obtained using the cumulative distribution function of EIA electricity generation data for all utility plants in 2003 (7). The minimum value represents the heat rate at which 5% of the electricity generated with the specific fuel is seen. Similarly the mean and maximum values are the heat rates at which 50% and 95% of the electricity has been generated with each fuel. As seen in Figure 6, the average heat rate for natural gas plants is lower than the average heat rate for coal plants, however the upper range of heat rates for natural gas plants surpasses the heat rates for coal plants.

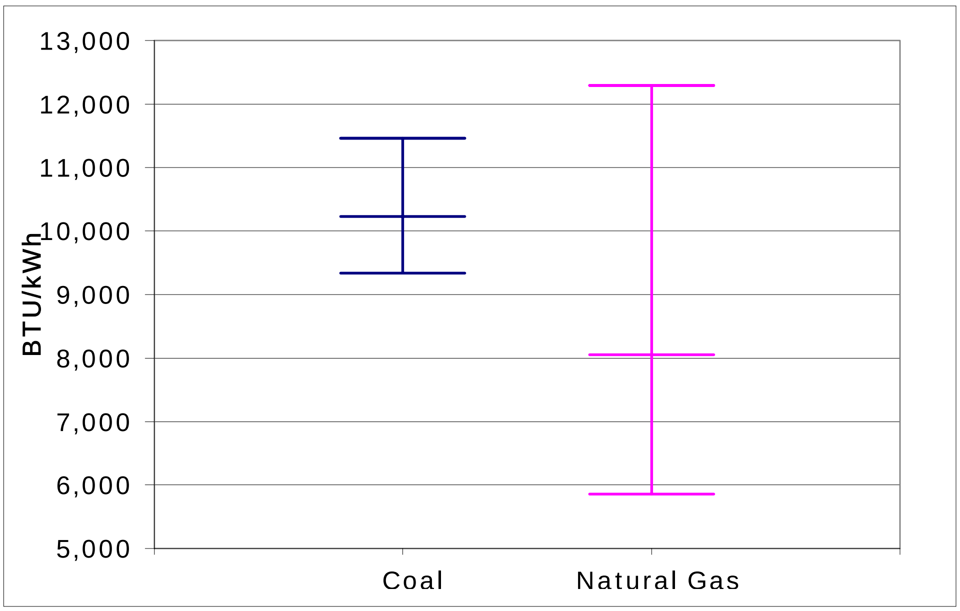

Figure 6: Natural Gas and Coal Plant Heat Rates (7).

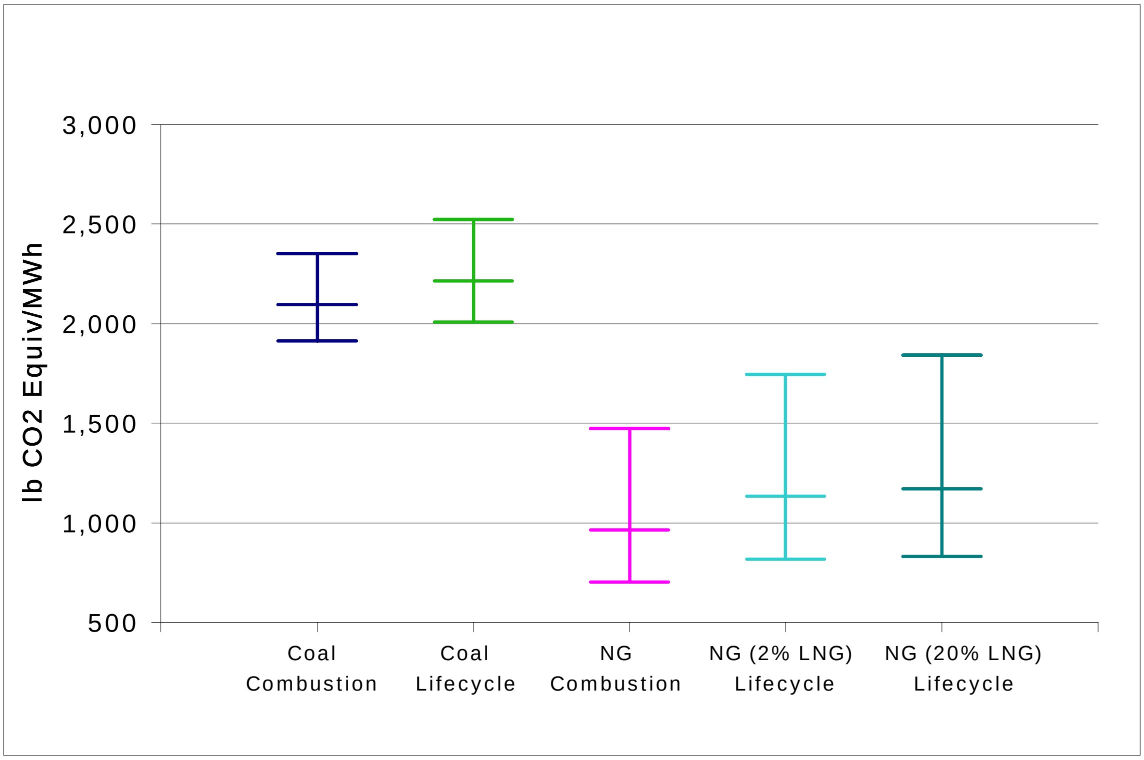

Figure 7: Emission Factors for Coal and Natural Gas Lifecycles.

Note that the average emission factor for coal combustion is higher than the emission factor for natural gas combustion. This does not change too much when the whole lifecycle is considered. More important seems to be the effect that including upstream emissions have in the range of emission factors for natural gas. While the average emission factor for the total coal lifecycle only increases by 5% compared to combustion emissions, the average emission factor for a natural gas mix with 20% LNG is 21% higher than the combustion emissions. Moreover, the maximum emission factor of the natural gas lifecycle gets closer to the minimum coal lifecycle emission factor. These results imply that if emissions at the combustion stage of the lifecycle could be controlled, natural gas would not be a much better alternative to coal in terms of greenhouse gas emissions.

New Generation Capacity

According to the DOE, by 2025 43 GW of inefficient gas and oil fired facilities will be retired, while 281 GW of new capacity will be installed (3). IGGC and NGCC power plants will probably be installed. These plants are generally more efficient than current technologies (average HHV Efficiencies are 37.5% and 50.2% respectively) (19) and thus have lower carbon emissions at the combustion stage. In addition, carbon capture and sequestration (CCS) can be performed more easily with these newer technologies. CCS is a process by which carbon emissions at the power plant are separated from other combustion products, captured and injected into underground geologic formations such as saline formations and depleted oil/gas fields. Experts believe that 90% CCS will be technologically and economically feasible in the future. Having CCS at IGCC and NGCC plants decreases the efficiency of the plants to average HHV efficiencies of 32.4% and 42.8% respectively (19) but overall lifecycle emissions would be greatly reduced and would be essentially the same for coal and natural gas (with 20% LNG). However, the major contributor for coal emissions would be at the combustion stage, while for natural gas the majority of the emissions would come from upstream processes. Figure 8, shows total emissions with CCS for IGCC and NGCC plants using average upstream emission factors of 11.6 lbs CO_2 Equiv/MMBTU and 25.6 lbs CO_2 Equiv/MMBTU for coal and natural gas respectively

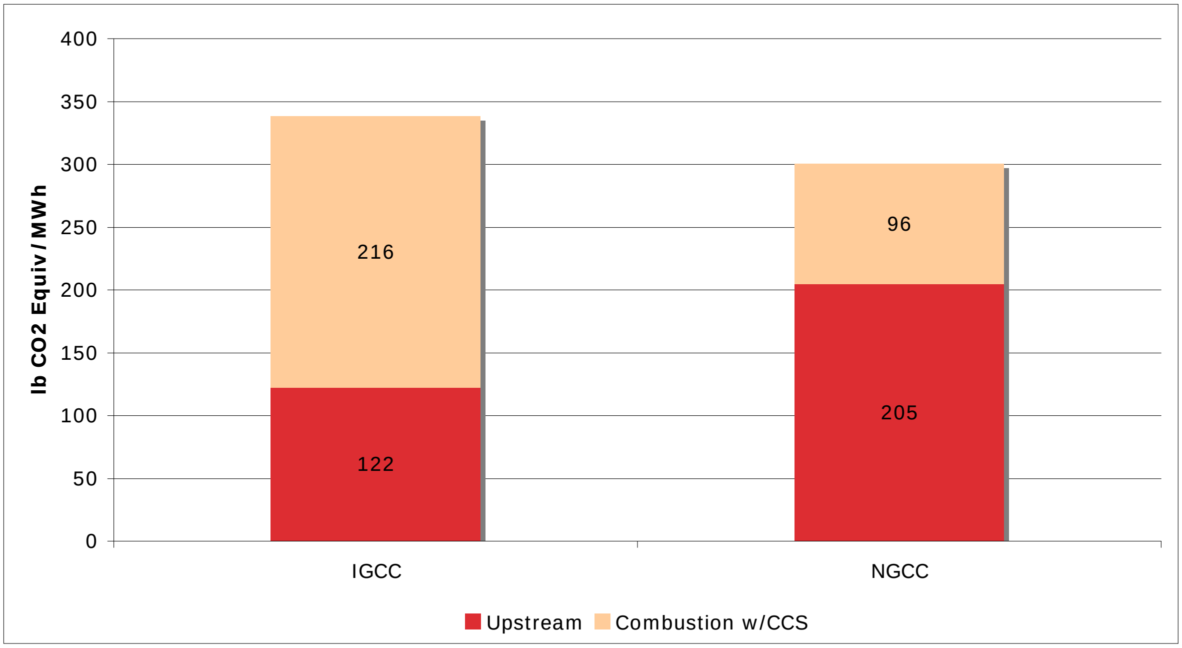

Figure 8: Lifecycle Emission Factors for IGCC and NGCC plants w/ CCS.

Discussion

It has been shown that there is high uncertainty about overall lifecycle carbon emissions for coal and LNG. In the future, as newer generation technologies and CCS are installed, overall emissions from electricity generated with coal and electricity generated with natural gas could be surprisingly similar. There is push right now from power generator to increase import of LNG. They seem to hope that the price of natural gas will decrease with these imports and they will be able to recover the investment they made in natural gas plants that are currently producing under capacity. These investments should be considered sunk costs and it is important to revaluate whether investing billions of dollars in LNG infrastructure will lead us into an energy path that cannot be easily changed as it will be harder to consider these investments as sunk costs once the expected environmental benefits are not achieved.

The analysis presented here only includes carbon emission, and no consideration was given to issues like energy security. Increasingly, LNG will come from areas of the world that are politically unstable. Policymakers should evaluate this increased dependence on foreign fuel before making decisions about future energy investments. In addition, the analysis presented only considers the use of natural gas for electricity generation. Natural gas is an indispensable fuel for many sectors of the US economy. As demand for natural gas from the electric utilities increases, these other sectors will probably be affected by higher natural gas prices. It is important to analyze whether these other sectors constitute a better use for natural gas than electricity generation, which has alternative fuels at its disposal.

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Executive Summary

An emissions inventory that identifies and quantifies a country's primary anthropogenic[1] sources and sinks of greenhouse gases is essential for addressing climate change. This inventory adheres to both (1) a comprehensive and detailed set of methodologies for estimating sources and sinks of anthropogenic greenhouse gases, and (2) a common and consistent mechanism that enables Parties to the United Nations Framework Convention on Climate Change (UNFCCC) to compare the relative contribution of different emission sources and greenhouse gases to climate change.

In 1992, the United States signed and ratified the UNFCCC. As stated in Article 2 of the UNFCCC, "The ultimate objective of this Convention and any related legal instruments that the Conference of the Parties may adopt is to achieve, in accordance with the relevant provisions of the Convention, stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner."[2]

Parties to the Convention, by ratifying, "shall develop, periodically update, publish and make available…national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol, using comparable methodologies…"[3] The United States views this report as an opportunity to fulfill these commitments.

This chapter summarizes the latest information on U.S. anthropogenic greenhouse gas emission trends from 1990 through 2010. To ensure that the U.S. emissions inventory is comparable to those of other UNFCCC Parties, the estimates presented here were calculated using methodologies consistent with those recommended in the Revised 1996 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), the IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000), and the IPCC Good Practice Guidance for Land Use, Land-Use Change, and Forestry (IPCC 2003). Additionally, the U.S. emission inventory has continued to incorporate new methodologies and data from the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006). The structure of this report is consistent with the UNFCCC guidelines for inventory reporting.[4] For most source categories, the IPCC methodologies were expanded, resulting in a more comprehensive and detailed estimate of emissions.

[BEGIN BOX]

Box ES- 1: Methodological approach for estimating and reporting U.S. emissions and sinks

In following the UNFCCC requirement under Article 4.1 to develop and submit national greenhouse gas emissions inventories, the emissions and sinks presented in this report are organized by source and sink categories and calculated using internationally-accepted methods provided by the IPCC.[5] Additionally, the calculated emissions and sinks in a given year for the United States are presented in a common manner in line with the UNFCCC reporting guidelines for the reporting of inventories under this international agreement.[6] The use of consistent methods to calculate emissions and sinks by all nations providing their inventories to the UNFCCC ensures that

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[1] The term "anthropogenic," in this context, refers to greenhouse gas emissions and removals that are a direct result of human activities or are the result of natural processes that have been affected by human activities (IPCC/UNEP/OECD/IEA 1997).

[2] Article 2 of the Framework Convention on Climate Change published by the UNEP/WMO Information Unit on Climate Change. See <http://unfccc.int>.

[3] Article 4(1)(a) of the United Nations Framework Convention on Climate Change (also identified in Article 12). Subsequent decisions by the Conference of the Parties elaborated the role of Annex I Parties in preparing national inventories. See <http://unfccc.int>.

[4] See < http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

[5] See < http://www.ipcc-nggip.iges.or.jp/public/index.html>.

[6] See < http://unfccc.int/national_reports/annex_i_ghg_inventories/national_inventories_submissions/items/5270.php>.

these reports are comparable. In this regard, U.S. emissions and sinks reported in this inventory report are comparable to emissions and sinks reported by other countries. Emissions and sinks provided in this inventory do not preclude alternative examinations, but rather this inventory report presents emissions and sinks in a common format consistent with how countries are to report inventories under the UNFCCC. The report itself follows this standardized format, and provides an explanation of the IPCC methods used to calculate emissions and sinks, and the manner in which those calculations are conducted.

On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published a rule for the mandatory reporting of greenhouse gases (GHG) from large GHG emissions sources in the United States. Implementation of 40 CFR Part 98 is referred to as the Greenhouse Gas Reporting Program (GHGRP). 40 CFR part 98 applies to direct greenhouse gas emitters, fossil fuel suppliers, industrial gas suppliers, and facilities that inject CO_2 underground for sequestration or other reasons. Reporting is at the facility level, except for certain suppliers of fossil fuels and industrial greenhouse gases. For calendar year 2010, the first year in which data were reported, facilities in 29 categories provided in 40 CFR part 98 were required to report their 2010 emissions by the September 30, 2011 reporting deadline.[7] The GHGRP dataset and the data presented in this inventory report are complementary and, as indicated in the respective planned improvements sections in this report's chapters, EPA is analyzing how to use facility-level GHGRP data to improve the national estimates presented in this inventory.

[END BOX]

ES.1. Background Information

Naturally occurring greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and ozone (O_3). Several classes of halogenated substances that contain fluorine, chlorine, or bromine are also greenhouse gases, but they are, for the most part, solely a product of industrial activities. Chlorofluorocarbons (CFCs) and hydrochlorofluorocarbons (HCFCs) are halocarbons that contain chlorine, while halocarbons that contain bromine are referred to as bromofluorocarbons (i.e., halons). As stratospheric ozone depleting substances, CFCs, HCFCs, and halons are covered under the Montreal Protocol on Substances that Deplete the Ozone Layer. The UNFCCC defers to this earlier international treaty. Consequently, Parties to the UNFCCC are not required to include these gases in their national greenhouse gas emission inventories.[8] Some other fluorine-containing halogenated substances—hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)—do not deplete stratospheric ozone but are potent greenhouse gases. These latter substances are addressed by the UNFCCC and accounted for in national greenhouse gas emission inventories.

There are also several gases that do not have a direct global warming effect but indirectly affect terrestrial and/or solar radiation absorption by influencing the formation or destruction of greenhouse gases, including tropospheric and stratospheric ozone. These gases include carbon monoxide (CO), oxides of nitrogen (NO_x), and non-CH_4 volatile organic compounds (NMVOCs). Aerosols, which are extremely small particles or liquid droplets, such as those produced by sulfur dioxide (SO_2) or elemental carbon emissions, can also affect the absorptive characteristics of the atmosphere.

Although the direct greenhouse gases CO_2, CH_4, and N_2O occur naturally in the atmosphere, human activities have changed their atmospheric concentrations. From the pre-industrial era (i.e., ending about 1750) to 2010, concentrations of these greenhouse gases have increased globally by 39, 158, and 19 percent, respectively (IPCC 2007 and NOAA/ESLR 2009).

Beginning in the 1950s, the use of CFCs and other stratospheric ozone depleting substances (ODS) increased by nearly 10 percent per year until the mid-1980s, when international concern about ozone depletion led to the entry into force of the Montreal Protocol. Since then, the production of ODS is being phased out. In recent years, use of ODS substitutes such as HFCs and PFCs has grown as they begin to be phased in as replacements for CFCs and

[7] See <http://www.epa.gov/climatechange/emissions/ghgrulemaking.html> and <http://ghgdata.epa.gov/ghgp/main.do>.

[8] Emissions estimates of CFCs, HCFCs, halons and other ozone-depleting substances are included in the annexes of the Inventory report for informational purposes.

HCFCs. Accordingly, atmospheric concentrations of these substitutes have been growing (IPCC 2007).

Global Warming Potentials

Gases in the atmosphere can contribute to the greenhouse effect both directly and indirectly. Direct effects occur when the gas itself absorbs radiation. Indirect radiative forcing occurs when chemical transformations of the substance produce other greenhouse gases, when a gas influences the atmospheric lifetimes of other gases, and/or when a gas affects atmospheric processes that alter the radiative balance of the earth (e.g., affect cloud formation or albedo).[9] The IPCC developed the Global Warming Potential (GWP) concept to compare the ability of each greenhouse gas to trap heat in the atmosphere relative to another gas.

The GWP of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas (IPCC 2001). Direct radiative effects occur when the gas itself is a greenhouse gas. The reference gas used is CO_2, and therefore GWP-weighted emissions are measured in teragrams (or million metric tons) of CO_2 equivalent (Tg CO_2 Eq.).[10,11] All gases in this Executive Summary are presented in units of Tg CO_2 Eq.

The UNFCCC reporting guidelines for national inventories were updated in 2006,[12] but continue to require the use of GWPs from the IPCC Second Assessment Report (SAR) (IPCC 1996). This requirement ensures that current estimates of aggregate greenhouse gas emissions for 1990 to 2010 are consistent with estimates developed prior to the publication of the IPCC Third Assessment Report (TAR) (IPCC 2001) and the IPCC Fourth Assessment Report (AR4) (IPCC 2007). Therefore, to comply with international reporting standards under the UNFCCC, official emission estimates are reported by the United States using SAR GWP values. All estimates are provided throughout the report in both CO_2 equivalents and unweighted units. A comparison of emission values using the SAR GWPs versus the TAR and AR4 GWPs can be found in Chapter 1 and, in more detail, in Annex 6.1 of this report. The GWP values used in this report are listed below in Table ES-1.

Table ES-1: Global Warming Potentials (100-Year Time Horizon) Used in this Report

Gas	**GWP**
CO_2	1
CH_4*	21
N_2O	310
HFC-23	11,700
HFC-32	650
HFC-125	2,800
HFC-134a	1,300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
CF_4	6,500
C_2F_6	9,200
C_4F_{10}	7,000
C_6F_{14}	7,400
SF_6	23,900

Source: IPCC (1996)
* The CH_4 GWP includes the direct effects and those indirect effects due

[9] Albedo is a measure of the Earth's reflectivity, and is defined as the fraction of the total solar radiation incident on a body that is reflected by it.

[10] Carbon comprises 12/44ths of carbon dioxide by weight.

[11] One teragram is equal to 10^{12} grams or one million metric tons.

[12] See <http://unfccc.int/resource/docs/2006/sbsta/eng/09.pdf>.

to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Global warming potentials are not provided for CO, NO_x, NMVOCs, SO_2, and aerosols because there is no agreed-upon method to estimate the contribution of gases that are short-lived in the atmosphere, spatially variable, or have only indirect effects on radiative forcing (IPCC 1996).

ES.2. Recent Trends in U.S. Greenhouse Gas Emissions and Sinks

In 2010, total U.S. greenhouse gas emissions were 6,821.8 Tg or million metric tons CO_2 Eq. Total U.S. emissions have increased by 10.5 percent from 1990 to 2010, and emissions increased from 2009 to 2010 by 3.2 percent (213.5 Tg CO_2 Eq.). The increase from 2009 to 2010 was primarily due to an increase in economic output resulting in an increase in energy consumption across all sectors, and much warmer summer conditions resulting in an increase in electricity demand for air conditioning that was generated primarily by combusting coal and natural gas. Since 1990, U.S. emissions have increased at an average annual rate of 0.5 percent.

Figure ES-1 through Figure ES-3 illustrate the overall trends in total U.S. emissions by gas, annual changes, and absolute change since 1990. Table ES-2 provides a detailed summary of U.S. greenhouse gas emissions and sinks for 1990 through 2010.

Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

Table ES-2: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks (Tg or million metric tons CO_2 Eq.)

Gas/Source	1990	2005	2006	2007	2008	2009	2010
CO_2	**5,100.5**	**6,107.6**	**6,019.0**	**6,118.6**	**5,924.3**	**5,500.5**	**5,706.4**
Fossil Fuel Combustion	4,738.3	5,746.5	5,653.0	5,757.8	5,571.5	5,206.2	5,387.8
Electricity Generation	1,820.8	2,402.1	2,346.4	2,412.8	2,360.9	2,146.4	2,258.4
Transportation	1,485.9	1,896.6	1,878.1	1,893.9	1,789.8	1,727.9	1,745.5
Industrial	846.4	816.4	848.1	844.4	806.5	726.6	777.8
Residential	338.3	357.9	321.5	341.6	349.3	339.0	340.2
Commercial	219.0	223.5	208.6	218.9	225.1	224.6	224.2
U.S. Territories	27.9	50.0	50.3	46.1	39.8	41.7	41.6
Non-Energy Use of Fuels	119.6	144.1	143.8	134.9	138.6	123.7	125.1
Iron and Steel Production & Metallurgical Coke Production	99.6	66.0	68.9	71.1	66.1	42.1	54.3
Natural Gas Systems	37.6	29.9	30.8	31.0	32.8	32.2	32.3
Cement Production	33.3	45.2	45.8	44.5	40.5	29.0	30.5
Lime Production	11.5	14.4	15.1	14.6	14.3	11.2	13.2
Incineration of Waste	8.0	12.5	12.5	12.7	11.9	11.7	12.1
Limestone and Dolomite Use	5.1	6.8	8.0	7.7	6.3	7.6	10.0
Ammonia Production	13.0	9.2	8.8	9.1	7.9	7.9	8.7
Cropland Remaining Cropland	7.1	7.9	7.9	8.2	8.6	7.2	8.0
Urea Consumption for Non-Agricultural Purposes	3.8	3.7	3.5	4.9	4.1	3.4	4.4
Soda Ash Production and Consumption	4.1	4.2	4.2	4.1	4.1	3.6	3.7
Petrochemical Production	3.3	4.2	3.8	3.9	3.4	2.7	3.3

Aluminum Production	6.8	4.1	3.8	4.3	4.5	3.0	3.0
Carbon Dioxide Consumption	1.4	1.3	1.7	1.9	1.8	1.8	2.2
Titanium Dioxide Production	1.2	1.8	1.8	1.9	1.8	1.6	1.9
Ferroalloy Production	2.2	1.4	1.5	1.6	1.6	1.5	1.7
Zinc Production	0.6	1.0	1.0	1.0	1.2	0.9	1.2
Phosphoric Acid Production	1.5	1.4	1.2	1.2	1.2	1.0	1.0
Wetlands Remaining Wetlands	1.0	1.1	0.9	1.0	1.0	1.1	1.0
Lead Production	0.5	0.6	0.6	0.6	0.5	0.5	0.5
Petroleum Systems	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Silicon Carbide Production and Consumption	0.4	0.2	0.2	0.2	0.2	0.1	0.2
Land Use, Land-Use Change, and Forestry (Sink)[a]	*(881.8)*	*(1,085.9)*	*(1,110.4)*	*(1,108.2)*	*(1,087.5)*	*(1,062.6)*	*(1,074.7)*
Wood Biomass and Ethanol Consumption[b]	*218.6*	*228.6*	*233.7*	*241.1*	*252.1*	*244.1*	*266.1*
International Bunker Fuels[c]	*111.8*	*109.8*	*128.4*	*127.6*	*133.7*	*122.3*	*127.8*
CH_4	**668.3**	**625.8**	**664.6**	**656.2**	**667.9**	**672.2**	**666.5**
Natural Gas Systems	189.6	190.5	217.7	205.3	212.7	220.9	215.4
Enteric Fermentation	133.8	139.0	141.4	143.8	143.4	142.6	141.3
Landfills	147.7	112.7	111.7	111.7	113.1	111.2	107.8
Coal Mining	84.1	56.8	58.1	57.8	66.9	70.1	72.6
Manure Management	31.7	47.9	48.4	52.7	51.8	50.7	52.0
Petroleum Systems	35.2	29.2	29.2	29.8	30.0	30.7	31.0
Wastewater Treatment	15.9	16.5	16.7	16.6	16.6	16.5	16.3
Rice Cultivation	7.1	6.8	5.9	6.2	7.2	7.3	8.6
Stationary Combustion	7.5	6.6	6.2	6.5	6.6	6.3	6.3
Abandoned Underground Coal Mines	6.0	5.5	5.5	5.3	5.3	5.1	5.0
Forest Land Remaining Forest Land	2.5	8.1	17.9	14.6	8.8	5.8	4.8
Mobile Combustion	4.7	2.5	2.4	2.2	2.1	2.0	1.9
Composting	0.3	1.6	1.6	1.7	1.7	1.6	1.6
Petrochemical Production	0.9	1.1	1.0	1.0	0.9	0.8	0.9
Iron and Steel Production & Metallurgical Coke Production	1.0	0.7	0.7	0.7	0.6	0.4	0.5
Field Burning of Agricultural Residues	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Ferroalloy Production	+	+	+	+	+	+	+
Silicon Carbide Production and Consumption	+	+	+	+	+	+	+
Incineration of Waste	+	+	+	+	+	+	+
International Bunker Fuesl[c]	0.2	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*	*0.2*
N_2O	**316.2**	**331.9**	**336.8**	**334.9**	**317.1**	**304.0**	**306.2**
Agricultural Soil Management	200.0	213.1	211.1	211.1	212.9	207.3	207.8
Stationary Combustion	12.3	20.6	20.8	21.2	21.1	20.7	22.6
Mobile Combustion	43.9	37.0	33.7	29.0	25.2	22.5	20.6
Manure Management	14.8	17.6	18.4	18.5	18.3	18.2	18.3
Nitric Acid Production	17.6	16.4	16.1	19.2	16.4	14.5	16.7
Wastewater Treatment	3.5	4.7	4.8	4.8	4.9	5.0	5.0
N_2O from Product Uses	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Forest Land Remaining Forest Land	2.1	7.0	15.0	12.2	7.5	5.1	4.3
Adipic Acid Production	15.8	7.4	8.9	10.7	2.6	2.8	2.8
Composting	0.4	1.7	1.8	1.8	1.9	1.8	1.7
Settlements Remaining Settlements	1.0	1.5	1.5	1.6	1.5	1.4	1.4
Incineration of Waste	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Field Burning of Agricultural Residues	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wetlands Remaining Wetlands	+	+	+	+	+	+	+
International Bunker Fuels[c]	*1.1*	*1.0*	*1.2*	*1.2*	*1.2*	*1.1*	*1.2*
HFCs	**36.9**	**115.0**	**116.0**	**120.0**	**117.5**	**112.1**	**123.0**
Substitution of Ozone Depleting	0.3	99.0	101.9	102.7	103.6	106.3	114.6

Substances							
HCFC-22 Production	36.4	15.8	13.8	17.0	13.6	5.4	8.1
Semiconductor Manufacture	0.2	0.2	0.3	0.3	0.3	0.3	0.3
PFCs	**20.6**	**6.2**	**6.0**	**7.5**	**6.6**	**5.6**	**5.6**
Semiconductor Manufacture	2.2	3.2	3.5	3.7	4.0	4.0	4.1
Aluminum Production	18.4	3.0	2.5	3.8	2.7	1.6	1.6
SF_6	**32.6**	**17.8**	**16.8**	**15.6**	**15.0**	**13.9**	**14.0**
Electrical Transmission and Distribution	26.7	13.9	13.0	12.2	12.2	11.8	11.8
Magnesium Production and Processing	5.4	2.9	2.9	2.6	1.9	1.1	1.3
Semiconductor Manufacture	0.5	1.0	1.0	0.8	0.9	1.0	0.9
Total	**6,175.2**	**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Net Emission (Sources and Sinks)	**5,293.4**	**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

+ Does not exceed 0.05 Tg CO_2 Eq.
[a] Parentheses indicate negative values or sequestration. The net CO_2 flux total includes both emissions and sequestration, and constitutes a net sink in the United States. Sinks are only included in net emissions total.
[b] Emissions from Wood Biomass and Ethanol Consumption are not included specifically in summing energy sector totals. Net carbon fluxes from changes in biogenic carbon reservoirs are accounted for in the estimates for Land Use, Land-Use Change, and Forestry.
[c] Emissions from International Bunker Fuels are not included in totals.
[d] Small amounts of PFC emissions also result from this source.
Note: Totals may not sum due to independent rounding.

Figure ES-4 illustrates the relative contribution of the direct greenhouse gases to total U.S. emissions in 2010. The primary greenhouse gas emitted by human activities in the United States was CO_2, representing approximately 83.6 percent of total greenhouse gas emissions. The largest source of CO_2, and of overall greenhouse gas emissions, was fossil fuel combustion. CH_4 emissions, which have decreased by 0.3 percent since 1990, resulted primarily from natural gas systems, enteric fermentation associated with domestic livestock, and decomposition of wastes in landfills. Agricultural soil management, mobile source fuel combustion and stationary fuel combustion were the major sources of N_2O emissions. Ozone depleting substance substitute emissions and emissions of HFC-23 during the production of HCFC-22 were the primary contributors to aggregate HFC emissions. PFC emissions resulted from semiconductor manufacturing and as a by-product of primary aluminum production, while electrical transmission and distribution systems accounted for most SF_6 emissions.

Figure ES-4: 2010 Greenhouse Gas Emissions by Gas (percentages based on Tg CO_2 Eq.)

Overall, from 1990 to 2010, total emissions of CO_2 increased by 605.9 Tg CO_2 Eq. (11.9 percent), while total emissions of CH_4 and N_2O decreased by 1.7 Tg CO_2 Eq. (0.3 percent), and 10.0 Tg CO_2 Eq. (3.2 percent), respectively. During the same period, aggregate weighted emissions of HFCs, PFCs, and SF_6 rose by 52.5 Tg CO_2 Eq. (58.2 percent). From 1990 to 2010, HFCs increased by 86.1 Tg CO_2 Eq. (233.1 percent), PFCs decreased by 15.0 Tg CO_2 Eq. (72.7 percent), and SF_6 decreased by 18.6 Tg CO_2 Eq. (57.0 percent). Despite being emitted in smaller quantities relative to the other principal greenhouse gases, emissions of HFCs, PFCs, and SF_6 are significant because many of these gases have extremely high global warming potentials and, in the cases of PFCs and SF_6, long atmospheric lifetimes. Conversely, U.S. greenhouse gas emissions were partly offset by carbon sequestration in forests, trees in urban areas, agricultural soils, and landfilled yard trimmings and food scraps, which, in aggregate, offset 15.8 percent of total emissions in 2010. The following sections describe each gas's contribution to total U.S. greenhouse gas emissions in more detail.

Carbon Dioxide Emissions

The global carbon cycle is made up of large carbon flows and reservoirs. Billions of tons of carbon in the form of CO_2 are absorbed by oceans and living biomass (i.e., sinks) and are emitted to the atmosphere annually through natural processes (i.e., sources). When in equilibrium, carbon fluxes among these various reservoirs are roughly balanced. Since the Industrial Revolution (i.e., about 1750), global atmospheric concentrations of CO_2 have risen about 39 percent (IPCC 2007 and NOAA/ESLR 2009), principally due to the combustion of fossil fuels. Within the

United States, fossil fuel combustion accounted for 94.4 percent of CO_2 emissions in 2010. Globally, approximately 30,313 Tg of CO_2 were added to the atmosphere through the combustion of fossil fuels in 2009, of which the United States accounted for about 18 percent.[13] Changes in land use and forestry practices can also emit CO_2 (e.g., through conversion of forest land to agricultural or urban use) or can act as a sink for CO_2 (e.g., through net additions to forest biomass). In addition to fossil-fuel combustion, several other sources emit significant quantities of CO_2. These sources include, but are not limited to non-energy use of fuels, iron and steel production and cement production (Figure ES-5).

Figure ES-5: 2010 Sources of CO_2 Emissions

As the largest source of U.S. greenhouse gas emissions, CO_2 from fossil fuel combustion has accounted for approximately 78 percent of GWP-weighted emissions since 1990, growing slowly from 77 percent of total GWP-weighted emissions in 1990 to 79 percent in 2010. Emissions of CO_2 from fossil fuel combustion increased at an average annual rate of 0.7 percent from 1990 to 2010. The fundamental factors influencing this trend include (1) a generally growing domestic economy over the last 21 years, and (2) an overall growth in emissions from electricity generation and transportation activities. Between 1990 and 2010, CO_2 emissions from fossil fuel combustion increased from 4,738.3 Tg CO_2 Eq. to 5,387.8 Tg CO_2 Eq.—a 13.7 percent total increase over the twenty-one-year period. From 2009 to 2010, these emissions increased by 181.6 Tg CO_2 Eq. (3.5 percent).

Historically, changes in emissions from fossil fuel combustion have been the dominant factor affecting U.S. emission trends. Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population and economic growth, energy price fluctuations, technological changes, and seasonal temperatures. In the short term, the overall consumption of fossil fuels in the United States fluctuates primarily in response to changes in general economic conditions, energy prices, weather, and the availability of non-fossil alternatives. For example, in a year with increased consumption of goods and services, low fuel prices, severe summer and winter weather conditions, nuclear plant closures, and lower precipitation feeding hydroelectric dams, there would likely be proportionally greater fossil fuel consumption than a year with poor economic performance, high fuel prices, mild temperatures, and increased output from nuclear and hydroelectric plants. In the long term, energy consumption patterns respond to changes that affect the scale of consumption (e.g., population, number of cars, and size of houses), the efficiency with which energy is used in equipment (e.g., cars, power plants, steel mills, and light bulbs) and behavioral choices (e.g., walking, bicycling, or telecommuting to work instead of driving).

Figure ES-6: 2010 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Figure ES-7: 2010 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

The five major fuel consuming sectors contributing to CO_2 emissions from fossil fuel combustion are electricity generation, transportation, industrial, residential, and commercial. CO_2 emissions are produced by the electricity generation sector as they consume fossil fuel to provide electricity to one of the other four sectors, or "end-use" sectors. For the discussion below, electricity generation emissions have been distributed to each end-use sector on the basis of each sector's share of aggregate electricity consumption. This method of distributing emissions assumes that each end-use sector consumes electricity that is generated from the national average mix of fuels according to their carbon intensity. Emissions from electricity generation are also addressed separately after the end-use sectors have been discussed.

Note that emissions from U.S. territories are calculated separately due to a lack of specific consumption data for the individual end-use sectors.

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[13] Global CO_2 emissions from fossil fuel combustion were taken from Energy Information Administration *International Energy Statistics 2010* < http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm> EIA (2010a).

Figure ES-6, Figure ES-7, and Table ES-3 summarize CO_2 emissions from fossil fuel combustion by end-use sector.

Table ES-3: CO_2 Emissions from Fossil Fuel Combustion by Fuel Consuming End-Use Sector (Tg or million metric tons CO_2 Eq.)

End-Use Sector	1990		2005	2006	2007	2008	2009	2010
Transportation	**1,489.0**		**1,901.3**	**1,882.6**	**1,899.0**	**1,794.5**	**1,732.4**	**1,750.0**
Combustion	1,485.9		1,896.6	1,878.1	1,893.9	1,789.8	1,727.9	1,745.5
Electricity	3.0		4.7	4.5	5.1	4.7	4.5	4.5
Industrial	**1,533.1**		**1,553.3**	**1,560.2**	**1,559.8**	**1,503.8**	**1,328.6**	**1,415.4**
Combustion	846.4		816.4	848.1	844.4	806.5	726.6	777.8
Electricity	686.8		737.0	712.0	715.4	697.3	602.0	637.6
Residential	**931.4**		**1,214.7**	**1,152.4**	**1,205.2**	**1,192.2**	**1,125.5**	**1,183.7**
Combustion	338.3		357.9	321.5	341.6	349.3	339.0	340.2
Electricity	593.0		856.7	830.8	863.5	842.9	786.5	843.5
Commercial	**757.0**		**1,027.2**	**1,007.6**	**1,047.7**	**1,041.1**	**978.0**	**997.1**
Combustion	219.0		223.5	208.6	218.9	225.1	224.6	224.2
Electricity	538.0		803.7	799.0	828.8	816.0	753.5	772.9
U.S. Territories[a]	**27.9**		**50.0**	**50.3**	**46.1**	**39.8**	**41.7**	**41.6**
Total	**4,738.3**		**5,746.5**	**5,653.0**	**5,757.8**	**5,571.5**	**5,206.2**	**5,387.8**
Electricity Generation	**1,820.8**		**2,402.1**	**2,346.4**	**2,412.8**	**2,360.9**	**2,146.4**	**2,258.4**

Note: Totals may not sum due to independent rounding. Combustion-related emissions from electricity generation are allocated based on aggregate national electricity consumption by each end-use sector.
[a] Fuel consumption by U.S. territories (i.e., American Samoa, Guam, Puerto Rico, U.S. Virgin Islands, Wake Island, and other U.S. Pacific Islands) is included in this report.

Transportation End-Use Sector. Transportation activities (excluding international bunker fuels) accounted for 32 percent of CO_2 emissions from fossil fuel combustion in 2010.[14] Virtually all of the energy consumed in this end-use sector came from petroleum products. Nearly 65 percent of the emissions resulted from gasoline consumption for personal vehicle use. The remaining emissions came from other transportation activities, including the combustion of diesel fuel in heavy-duty vehicles and jet fuel in aircraft. From 1990 to 2010, transportation emissions rose by 18 percent due, in large part, to increased demand for travel and the stagnation of fuel efficiency across the U.S. vehicle fleet. The number of vehicle miles traveled by light-duty motor vehicles (passenger cars and light-duty trucks) increased 34 percent from 1990 to 2010, as a result of a confluence of factors including population growth, economic growth, urban sprawl, and low fuel prices over much of this period.

Industrial End-Use Sector. Industrial CO_2 emissions, resulting both directly from the combustion of fossil fuels and indirectly from the generation of electricity that is consumed by industry, accounted for 26 percent of CO_2 from fossil fuel combustion in 2010. Approximately 55 percent of these emissions resulted from direct fossil fuel combustion to produce steam and/or heat for industrial processes. The remaining emissions resulted from consuming electricity for motors, electric furnaces, ovens, lighting, and other applications. In contrast to the other end-use sectors, emissions from industry have steadily declined since 1990. This decline is due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and efficiency improvements.

Residential and Commercial End-Use Sectors. The residential and commercial end-use sectors accounted for 22 and 19 percent, respectively, of CO_2 emissions from fossil fuel combustion in 2010. Both sectors relied heavily on electricity for meeting energy demands, with 71 and 78 percent, respectively, of their emissions attributable to electricity consumption for lighting, heating, cooling, and operating appliances. The remaining emissions were due to the consumption of natural gas and petroleum for heating and cooking. Emissions from these end-use sectors have increased 29 percent since 1990, due to increasing electricity consumption for lighting, heating, air conditioning, and operating appliances.

[14] If emissions from international bunker fuels are included, the transportation end-use sector accounted for 34.0 percent of U.S. emissions from fossil fuel combustion in 2010.

Electricity Generation. The United States relies on electricity to meet a significant portion of its energy demands. Electricity generators consumed 36 percent of U.S. energy from fossil fuels and emitted 42 percent of the CO_2 from fossil fuel combustion in 2010. The type of fuel combusted by electricity generators has a significant effect on their emissions. For example, some electricity is generated with low CO_2 emitting energy technologies, particularly non-fossil options such as nuclear, hydroelectric, or geothermal energy. However, electricity generators rely on coal for over half of their total energy requirements and accounted for 94 percent of all coal consumed for energy in the United States in 2010. Consequently, changes in electricity demand have a significant impact on coal consumption and associated CO_2 emissions.

Other significant CO_2 trends included the following:

- CO_2 emissions from non-energy use of fossil fuels have increased 5.5 Tg CO_2 Eq. (4.6 percent) from 1990 through 2010. Emissions from non-energy uses of fossil fuels were 125.1 Tg CO_2 Eq. in 2010, which constituted 2.2 percent of total national CO_2 emissions, approximately the same proportion as in 1990.
- CO_2 emissions from iron and steel production and metallurgical coke production increased by 12.2 Tg CO_2 Eq. (28.9 percent) from 2009 to 2010, upsetting a trend of decreasing emissions. Despite this, from 1990 through 2010 emissions declined by 45.5 percent (45.3 Tg CO_2 Eq.). This decline is due to the restructuring of the industry, technological improvements, and increased scrap utilization.
- In 2010, CO_2 emissions from cement production increased by 1.5 Tg CO_2 Eq. (5.1 percent) from 2009. After decreasing in 1991 by two percent from 1990 levels, cement production emissions grew every year through 2006; emissions decreased in the three years prior to 2010. Overall, from 1990 to 2010, emissions from cement production have decreased by 8.3 percent, a decrease of 2.8 Tg CO_2 Eq.
- Net CO_2 uptake from Land Use, Land-Use Change, and Forestry increased by 192.8 Tg CO_2 Eq. (21.9 percent) from 1990 through 2010. This increase was primarily due to an increase in the rate of net carbon accumulation in forest carbon stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual carbon accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of carbon accumulation in urban trees increased.

Methane Emissions

Methane (CH_4) is more than 20 times as effective as CO_2 at trapping heat in the atmosphere (IPCC 1996). Over the last two hundred and fifty years, the concentration of CH_4 in the atmosphere increased by 158 percent (IPCC 2007). Anthropogenic sources of CH_4 include natural gas and petroleum systems, agricultural activities, landfills, coal mining, wastewater treatment, stationary and mobile combustion, and certain industrial processes (see Figure ES-8).

Figure ES-8: 2010 Sources of CH_4 Emissions

Some significant trends in U.S. emissions of CH_4 include the following:

- Natural gas systems were the largest anthropogenic source category of CH_4 emissions in the United States in 2010 with 215.4 Tg CO_2 Eq. of CH_4 emitted into the atmosphere. Those emissions have increased by 25.8 Tg CO_2 Eq. (13.6 percent) since 1990.
- Enteric fermentation is the second largest anthropogenic source of CH_4 emissions in the United States. In 2010, enteric fermentation CH_4 emissions were 141.3 Tg CO_2 Eq. (21.2 percent of total CH_4 emissions), which represents an increase of 7.5 Tg CO_2 Eq. (5.6 percent) since 1990.
- Landfills are the third largest anthropogenic source of CH_4 emissions in the United States, accounting for 16.2 percent of total CH_4 emissions (107.8 Tg CO_2 Eq.) in 2010. From 1990 to 2010, CH_4 emissions from landfills decreased by 39.8 Tg CO_2 Eq. (27.0 percent), with small increases occurring in some interim years. This downward trend in overall emissions is the result of increases in the amount of landfill gas

collected and combusted,[15] which has more than offset the additional CH_4 emissions resulting from an increase in the amount of municipal solid waste landfilled.

- In 2010, CH_4 emissions from coal mining were 72.6 Tg CO_2 Eq., a 2.5 Tg CO_2 Eq. (3.5 percent) increase over 2009 emission levels. The overall decline of 11.5 Tg CO_2 Eq. (13.6 percent) from 1990 results from the mining of less gassy coal from underground mines and the increased use of CH_4 collected from degasification systems.
- Methane emissions from manure management increased by 64.0 percent since 1990, from 31.7 Tg CO_2 Eq. in 1990 to 52.0 Tg CO_2 Eq. in 2010. The majority of this increase was from swine and dairy cow manure, since the general trend in manure management is one of increasing use of liquid systems, which tends to produce greater CH_4 emissions. The increase in liquid systems is the combined result of a shift to larger facilities, and to facilities in the West and Southwest, all of which tend to use liquid systems. Also, new regulations limiting the application of manure nutrients have shifted manure management practices at smaller dairies from daily spread to manure managed and stored on site.

Nitrous Oxide Emissions

N_2O is produced by biological processes that occur in soil and water and by a variety of anthropogenic activities in the agricultural, energy-related, industrial, and waste management fields. While total N_2O emissions are much lower than CO_2 emissions, N_2O is approximately 300 times more powerful than CO_2 at trapping heat in the atmosphere (IPCC 1996). Since 1750, the global atmospheric concentration of N_2O has risen by approximately 19 percent (IPCC 2007). The main anthropogenic activities producing N_2O in the United States are agricultural soil management, fuel combustion in motor vehicles, stationary fuel combustion, manure management and nitric acid production (see Figure ES-9).

Figure ES-9: 2010 Sources of N_2O Emissions

Some significant trends in U.S. emissions of N_2O include the following:

- In 2010, N_2O emissions from mobile combustion were 20.6 Tg CO_2 Eq. (approximately 6.7 percent of U.S. N_2O emissions). From 1990 to 2010, N_2O emissions from mobile combustion decreased by 53.1 percent. However, from 1990 to 1998 emissions increased by 25.6 percent, due to control technologies that reduced NO_x emissions while increasing N_2O emissions. Since 1998, newer control technologies have led to an overall decline in N_2O from this source.
- N_2O emissions from adipic acid production were 2.8 Tg CO_2 Eq. in 2010, and have decreased significantly in recent years due to the widespread installation of pollution control measures. Emissions from adipic acid production have decreased by 82.2 percent since 1990 and by 84.0 percent since a peak in 1995.
- N_2O emissions from stationary combustion increased 10.3 Tg CO_2 Eq. (84.4 percent) from 1990 through 2010. N_2O emissions from this source increased primarily as a result of an increase in the number of coal fluidized bed boilers in the electric power sector.
- Agricultural soils accounted for approximately 67.9 percent of N_2O emissions in the United States in 2010. Estimated emissions from this source in 2010 were 207.8 Tg CO_2 Eq. Annual N_2O emissions from agricultural soils fluctuated between 1990 and 2010, although overall emissions were 3.9 percent higher in 2010 than in 1990.

HFC, PFC, and SF_6 Emissions

HFCs and PFCs are families of synthetic chemicals that are used as alternatives to ODS, which are being phased out under the Montreal Protocol and Clean Air Act Amendments of 1990. HFCs and PFCs do not deplete the

[15] The CO_2 produced from combusted landfill CH_4 at landfills is not counted in national inventories as it is considered part of the natural C cycle of decomposition.

stratospheric ozone layer, and are therefore acceptable alternatives under the Montreal Protocol.

These compounds, however, along with SF_6, are potent greenhouse gases. In addition to having high global warming potentials, SF_6 and PFCs have extremely long atmospheric lifetimes, resulting in their essentially irreversible accumulation in the atmosphere once emitted. Sulfur hexafluoride is the most potent greenhouse gas the IPCC has evaluated (IPCC 1996).

Other emissive sources of these gases include electrical transmission and distribution systems, HCFC-22 production, semiconductor manufacturing, aluminum production, and magnesium production and processing (see Figure ES-10).

Figure ES-10: 2010 Sources of HFCs, PFCs, and SF_6 Emissions

Some significant trends in U.S. HFC, PFC, and SF_6 emissions include the following:

- Emissions resulting from the substitution of ozone depleting substances (ODS) (e.g., CFCs) have been consistently increasing, from small amounts in 1990 to 114.6 Tg CO_2 Eq. in 2010. Emissions from ODS substitutes are both the largest and the fastest growing source of HFC, PFC, and SF_6 emissions. These emissions have been increasing as phase-out of ODS required under the Montreal Protocol came into effect, especially after 1994, when full market penetration was made for the first generation of new technologies featuring ODS substitutes.
- HFC emissions from the production of HCFC-22 decreased by 77.8 percent (28.3 Tg CO_2 Eq.) from 1990 through 2010, due to a steady decline in the emission rate of HFC-23 (i.e., the amount of HFC-23 emitted per kilogram of HCFC-22 manufactured) and the use of thermal oxidation at some plants to reduce HFC-23 emissions.
- SF_6 emissions from electric power transmission and distribution systems decreased by 55.7 percent (14.9 Tg CO_2 Eq.) from 1990 to 2010, primarily because of higher purchase prices for SF_6 and efforts by industry to reduce emissions.
- PFC emissions from aluminum production decreased by 91.5 percent (16.9 Tg CO_2 Eq.) from 1990 to 2010, due to both industry emission reduction efforts and declines in domestic aluminum production.

ES.3. Overview of Sector Emissions and Trends

In accordance with the Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC/UNEP/OECD/IEA 1997), and the 2003 UNFCCC Guidelines on Reporting and Review (UNFCCC 2003), Figure ES-11 and Table ES-4 aggregate emissions and sinks by these chapters. Emissions of all gases can be summed from each source category from IPCC guidance. Over the twenty-one-year period of 1990 to 2010, total emissions in the Energy and Agriculture sectors grew by 645.8 Tg CO_2 Eq. (12.2 percent), and 40.6 Tg CO_2 Eq. (10.5 percent), respectively. Emissions slightly decreased in the Industrial Processes sector by 10.5 Tg CO_2 Eq. (3.4 percent) , while emissions from the Waste and Solvent and Other Product Use sectors decreased by 35.2 Tg CO_2 Eq. (21.0 percent) and less than 0.1 Tg CO_2 Eq. (0.4 percent), respectively. Over the same period, estimates of net C sequestration in the Land Use, Land-Use Change, and Forestry (LULUCF) sector (magnitude of emissions plus CO_2 flux from all LULUCF source categories) increased by 187.0 Tg CO_2 Eq. (21.5 percent).

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

Table ES-4: Recent Trends in U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector (Tg or million metric tons CO_2 Eq.)

Chapter/IPCC Sector	1990		2005	2006	2007	2008	2009	2010
Energy	5,287.7		6,282.4	6,214.4	6,294.3	6,125.4	5,752.7	5,933.5
Industrial Processes	313.9		330.1	335.5	347.3	319.1	268.2	303.4

Solvent and Other Product Use	4.4	4.4	4.4	4.4	4.4	4.4	4.4
Agriculture	387.8	424.6	425.4	432.6	433.8	426.4	428.4
Land-Use Change and Forestry	13.8	25.6	43.2	37.6	27.4	20.6	19.6
Waste	167.7	137.2	136.5	136.7	138.2	136.0	132.5
Total Emissions	**6,175.2**	**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Land-Use Change and Forestry (Sinks)	(881.8)	(1,085.9)	(1,110.4)	(1,108.2)	(1,087.5)	(1,062.6)	(1,074.7)
Net Emissions (Emissions and Sinks)	**5,293.4**	**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

* The net CO_2 flux total includes both emissions and sequestration, and constitutes a sink in the United States. Sinks are only included in net emissions total.
Note: Totals may not sum due to independent rounding. Parentheses indicate negative values or sequestration.

Energy

The Energy chapter contains emissions of all greenhouse gases resulting from stationary and mobile energy activities including fuel combustion and fugitive fuel emissions. Energy-related activities, primarily fossil fuel combustion, accounted for the vast majority of U.S. CO_2 emissions for the period of 1990 through 2010. In 2010, approximately 85 percent of the energy consumed in the United States (on a Btu basis) was produced through the combustion of fossil fuels. The remaining 15 percent came from other energy sources such as hydropower, biomass, nuclear, wind, and solar energy (see Figure ES-12). Energy-related activities are also responsible for CH_4 and N_2O emissions (50 percent and 14 percent of total U.S. emissions of each gas, respectively). Overall, emission sources in the Energy chapter account for a combined 87.0 percent of total U.S. greenhouse gas emissions in 2010.

Figure ES-12: 2010 U.S. Energy Consumption by Energy Source

Industrial Processes

The Industrial Processes chapter contains by-product or fugitive emissions of greenhouse gases from industrial processes not directly related to energy activities such as fossil fuel combustion. For example, industrial processes can chemically transform raw materials, which often release waste gases such as CO_2, CH_4, and N_2O. These processes include iron and steel production and metallurgical coke production, cement production, ammonia production and urea consumption, lime production, limestone and dolomite use (e.g., flux stone, flue gas desulfurization, and glass manufacturing), soda ash production and consumption, titanium dioxide production, phosphoric acid production, ferroalloy production, CO_2 consumption, silicon carbide production and consumption, aluminum production, petrochemical production, nitric acid production, adipic acid production, lead production, and zinc production. Additionally, emissions from industrial processes release HFCs, PFCs, and SF_6. Overall, emission sources in the Industrial Process chapter account for 4.4 percent of U.S. greenhouse gas emissions in 2010.

Solvent and Other Product Use

The Solvent and Other Product Use chapter contains greenhouse gas emissions that are produced as a by-product of various solvent and other product uses. In the United States, emissions from N_2O from product uses, the only source of greenhouse gas emissions from this sector, accounted for about 0.1 percent of total U.S. anthropogenic greenhouse gas emissions on a carbon equivalent basis in 2010.

Agriculture

The Agricultural chapter contains anthropogenic emissions from agricultural activities (except fuel combustion, which is addressed in the Energy chapter, and agricultural CO_2 fluxes, which are addressed in the Land Use, Land-Use Change, and Forestry Chapter). Agricultural activities contribute directly to emissions of greenhouse gases through a variety of processes, including the following source categories: enteric fermentation in domestic livestock, livestock manure management, rice cultivation, agricultural soil management, and field burning of agricultural residues. CH_4 and N_2O were the primary greenhouse gases emitted by agricultural activities. CH_4 emissions from enteric fermentation and manure management represented 21.2 percent and 7.8 percent of total CH_4 emissions from anthropogenic activities, respectively, in 2010. Agricultural soil management activities such as fertilizer application and other cropping practices were the largest source of U.S. N_2O emissions in 2010, accounting for 67.9 percent. In 2010, emission sources accounted for in the Agricultural chapters were responsible for 6.3 percent of total U.S. greenhouse gas emissions.

Land Use, Land-Use Change, and Forestry

The Land Use, Land-Use Change, and Forestry chapter contains emissions of CH_4 and N_2O, and emissions and removals of CO_2 from forest management, other land-use activities, and land-use change. Forest management practices, tree planting in urban areas, the management of agricultural soils, and the landfilling of yard trimmings and food scraps resulted in a net uptake (sequestration) of C in the United States. Forests (including vegetation, soils, and harvested wood) accounted for 86 percent of total 2010 net CO_2 flux, urban trees accounted for 9 percent, mineral and organic soil carbon stock changes accounted for 4 percent, and landfilled yard trimmings and food scraps accounted for 1 percent of the total net flux in 2010. The net forest sequestration is a result of net forest growth and increasing forest area, as well as a net accumulation of carbon stocks in harvested wood pools. The net sequestration in urban forests is a result of net tree growth in these areas. In agricultural soils, mineral and organic soils sequester approximately 5 times as much C as is emitted from these soils through liming and urea fertilization. The mineral soil C sequestration is largely due to the conversion of cropland to permanent pastures and hay production, a reduction in summer fallow areas in semi-arid areas, an increase in the adoption of conservation tillage practices, and an increase in the amounts of organic fertilizers (i.e., manure and sewage sludge) applied to agriculture lands. The landfilled yard trimmings and food scraps net sequestration is due to the long-term accumulation of yard trimming carbon and food scraps in landfills.

Land use, land-use change, and forestry activities in 2010 resulted in a net C sequestration of 1,074.7 Tg CO_2 Eq. (Table ES-5). This represents an offset of 18.8 percent of total U.S. CO_2 emissions, or 15.8 percent of total greenhouse gas emissions in 2010. Between 1990 and 2010, total land use, land-use change, and forestry net C flux resulted in a 21.9 percent increase in CO_2 sequestration, primarily due to an increase in the rate of net C accumulation in forest C stocks, particularly in aboveground and belowground tree biomass, and harvested wood pools. Annual C accumulation in landfilled yard trimmings and food scraps slowed over this period, while the rate of annual C accumulation increased in urban trees.

Table ES-5: Net CO_2 Flux from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Sink Category	**1990**		**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Forest Land Remaining Forest Land	(701.4)		(940.9)	(963.5)	(959.2)	(938.3)	(910.6)	(921.8)
Cropland Remaining Cropland	(29.4)		(18.3)	(19.1)	(19.7)	(18.1)	(17.4)	(15.6)
Land Converted to Cropland	2.2		5.9	5.9	5.9	5.9	5.9	5.9
Grassland Remaining Grassland	(52.2)		(8.9)	(8.8)	(8.6)	(8.5)	(8.3)	(8.3)
Land Converted to Grassland	(19.8)		(24.4)	(24.2)	(24.0)	(23.8)	(23.6)	(23.6)
Settlements Remaining Settlements	(57.1)		(87.8)	(89.8)	(91.9)	(93.9)	(95.9)	(98.0)
Other (Landfilled Yard Trimmings and Food Scraps)	(24.2)		(11.6)	(11.0)	(10.9)	(10.9)	(12.7)	(13.3)
Total	**(881.8)**		**(1,085.9)**	**(1,110.4)**	**(1,108.2)**	**(1,087.5)**	**(1,062.6)**	**(1,074.7)**

Note: Totals may not sum due to independent rounding. Parentheses indicate net sequestration.

Emissions from Land Use, Land-Use Change, and Forestry are shown in Table ES-6. Liming of agricultural soils and urea fertilization in 2010 resulted in CO_2 emissions of 3.9 Tg CO_2 Eq. (3,906 Gg) and 4.1 Tg CO_2 Eq. (4,143 Gg), respectively. Lands undergoing peat extraction (i.e., *Peatlands Remaining Peatlands*) resulted in CO_2 emissions of 1.0 Tg CO_2 Eq. (983 Gg), and N_2O emissions of less than 0.05 Tg CO_2 Eq. The application of synthetic fertilizers to forest soils in 2010 resulted in direct N_2O emissions of 0.4 Tg CO_2 Eq. (1 Gg). Direct N_2O emissions from fertilizer application to forest soils have increased by 455 percent since 1990, but still account for a relatively small portion of overall emissions. Additionally, direct N_2O emissions from fertilizer application to settlement soils in 2010 accounted for 1.4 Tg CO_2 Eq. (5 Gg). This represents an increase of 43 percent since 1990. Forest fires in 2010 resulted in CH_4 emissions of 4.8 Tg CO_2 Eq. (231 Gg), and in N_2O emissions of 4.0 Tg CO_2 Eq. (14 Gg).

Table ES-6: Emissions from Land Use, Land-Use Change, and Forestry (Tg or million metric tons CO_2 Eq.)

Source Category	1990	2005	2006	2007	2008	2009	2010
CO_2	**8.1**	**8.9**	**8.8**	**9.2**	**9.6**	**8.3**	**9.0**
Cropland Remaining Cropland: Liming of Agricultural Soils	4.7	4.3	4.2	4.5	5.0	3.7	3.9
Cropland Remaining Cropland: Urea Fertilization	2.4	3.5	3.7	3.8	3.6	3.6	4.1
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	1.0	1.1	0.9	1.0	1.0	1.1	1.0
CH_4	**2.5**	**8.1**	**17.9**	**14.6**	**8.8**	**5.8**	**4.8**
Forest Land Remaining Forest Land: Forest Fires	2.5	8.1	17.9	14.6	8.8	5.8	4.8
N_2O	**3.1**	**8.5**	**16.5**	**13.8**	**9.0**	**6.5**	**5.7**
Forest Land Remaining Forest Land: Forest Fires	2.1	6.6	14.6	11.9	7.2	4.7	4.0
Forest Land Remaining Forest Land: Forest Soils	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Settlements Remaining Settlements: Settlement Soils	1.0	1.5	1.5	1.6	1.5	1.4	1.4
Wetlands Remaining Wetlands: Peatlands Remaining Peatlands	+	+	+	+	+	+	+
Total	**13.8**	**25.6**	**43.2**	**37.6**	**27.4**	**20.6**	**19.6**

+ Less than 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Waste

The Waste chapter contains emissions from waste management activities (except incineration of waste, which is addressed in the Energy chapter). Landfills were the largest source of anthropogenic greenhouse gas emissions in the Waste chapter, accounting for 81.4 percent of this chapter's emissions, and 16.2 percent of total U.S. CH_4 emissions.[16] Additionally, wastewater treatment accounts for 16.1 percent of Waste emissions, 2.5 percent of U.S. CH_4 emissions, and 1.6 percent of U.S. N_2O emissions. Emissions of CH_4 and N_2O from composting are also accounted for in this chapter; generating emissions of 1.6 Tg CO_2 Eq. and 1.7 Tg CO_2 Eq., respectively. Overall, emission sources accounted for in the Waste chapter generated 1.9 percent of total U.S. greenhouse gas emissions in 2010.

ES.4. Other Information

Emissions by Economic Sector

Throughout the Inventory of U.S. Greenhouse Gas Emissions and Sinks report, emission estimates are grouped into six sectors (i.e., chapters) defined by the IPCC: Energy; Industrial Processes; Solvent Use; Agriculture; Land Use, Land-Use Change, and Forestry; and Waste. While it is important to use this characterization for consistency with UNFCCC reporting guidelines, it is also useful to allocate emissions into more commonly used sectoral categories. This section reports emissions by the following economic sectors: Residential, Commercial, Industry, Transportation, Electricity Generation, Agriculture, and U.S. Territories.

Table ES-7 summarizes emissions from each of these sectors, and Figure ES-13 shows the trend in emissions by sector from 1990 to 2010.

Figure ES-13: Emissions Allocated to Economic Sectors

[16] Landfills also store carbon, due to incomplete degradation of organic materials such as wood products and yard trimmings, as described in the Land-Use, Land-Use Change, and Forestry chapter of the Inventory report.

Table ES-7: U.S. Greenhouse Gas Emissions Allocated to Economic Sectors (Tg or million metric tons CO_2 Eq.)

Implied Sectors	1990		2005	2006	2007	2008	2009	2010
Electric Power Industry	1,866.2		2,448.8	2,393.0	2,459.1	2,405.8	2,191.4	2,306.5
Transportation	1,545.2		2,017.5	1,994.5	2,002.4	1,889.8	1,819.3	1,834.0
Industry	1,564.8		1,438.1	1,499.8	1,489.6	1,448.5	1,317.2	1,394.2
Agriculture	431.9		496.0	516.7	517.6	505.8	492.8	494.8
Commercial	388.0		374.3	359.9	372.2	381.8	382.0	381.7
Residential	345.4		371.3	336.1	358.4	368.4	360.0	365.2
U.S. Territories	33.7		58.2	59.3	53.5	48.4	45.5	45.5
Total Emissions	**6,175.2**		**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Land Use, Land-Use Change, and Forestry (Sinks)	(881.8)		(1,085.9)	(1,110.4)	(1,108.2)	(1,087.5)	(1,062.6)	(1,074.7)
Net Emissions (Sources and Sinks)	**5,293.4**		**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

Note: Totals may not sum due to independent rounding. Emissions include CO_2, CH_4, N_2O, HFCs, PFCs, and SF_6.
See Table 2-12 for more detailed data.

Using this categorization, emissions from electricity generation accounted for the largest portion (34 percent) of U.S. greenhouse gas emissions in 2010. Transportation activities, in aggregate, accounted for the second largest portion (27 percent), while emissions from industry accounted for the third largest portion (20 percent) of U.S. greenhouse gas emissions in 2010. In contrast to electricity generation and transportation, emissions from industry have in general declined over the past decade. The long-term decline in these emissions has been due to structural changes in the U.S. economy (i.e., shifts from a manufacturing-based to a service-based economy), fuel switching, and energy efficiency improvements. The remaining 19 percent of U.S. greenhouse gas emissions were contributed by, in order of importance, the agriculture, commercial, and residential sectors, plus emissions from U.S. territories. Activities related to agriculture accounted for 7 percent of U.S. emissions; unlike other economic sectors, agricultural sector emissions were dominated by N_2O emissions from agricultural soil management and CH_4 emissions from enteric fermentation. The commercial and residential sectors accounted for 6 and 5 percent, respectively, of emissions and U.S. territories accounted for 1 percent of emissions; emissions from these sectors primarily consisted of CO_2 emissions from fossil fuel combustion.

CO_2 was also emitted and sequestered by a variety of activities related to forest management practices, tree planting in urban areas, the management of agricultural soils, and landfilling of yard trimmings.

Electricity is ultimately consumed in the economic sectors described above. Table ES-8 presents greenhouse gas emissions from economic sectors with emissions related to electricity generation distributed into end-use categories (i.e., emissions from electricity generation are allocated to the economic sectors in which the electricity is consumed). To distribute electricity emissions among end-use sectors, emissions from the source categories assigned to electricity generation were allocated to the residential, commercial, industry, transportation, and agriculture economic sectors according to retail sales of electricity.[17] These source categories include CO_2 from fossil fuel combustion and the use of limestone and dolomite for flue gas desulfurization, CO_2 and N_2O from incineration of waste, CH_4 and N_2O from stationary sources, and SF_6 from electrical transmission and distribution systems.

When emissions from electricity are distributed among these sectors, industrial activities account for the largest share of U.S. greenhouse gas emissions (30 percent) in 2010. Transportation is the second largest contributor to total U.S. emissions (27 percent). The residential and commercial sectors contributed the next largest shares of total U.S. greenhouse gas emissions in 2010. Emissions from these sectors increase substantially when emissions from electricity are included, due to their relatively large share of electricity consumption (e.g., lighting, appliances, etc.). In all sectors except agriculture, CO_2 accounts for more than 80 percent of greenhouse gas emissions, primarily from the combustion of fossil fuels. Figure ES-14 shows the trend in these emissions by sector from 1990 to 2010.

Table ES-8: U.S Greenhouse Gas Emissions by Economic Sector with Electricity-Related Emissions Distributed

[17] Emissions were not distributed to U.S. territories, since the electricity generation sector only includes emissions related to the generation of electricity in the 50 states and the District of Columbia.

(Tg or million metric tons CO_2 Eq.)

Implied Sectors	**1990**		**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Industry	2,237.7		2,159.9	2,198.5	2,185.9	2,131.5	1,905.8	2,019.0
Transportation	1,548.3		2,022.3	1,999.1	2,007.6	1,894.6	1,823.9	1,838.6
Residential	953.2		1,244.6	1,183.4	1,238.5	1,227.3	1,162.9	1,226.6
Commercial	939.4		1,193.6	1,174.8	1,216.9	1,213.3	1,151.3	1,171.0
Agriculture	462.9		525.5	544.2	550.5	533.3	518.9	521.1
U.S. Territories	33.7		58.2	59.3	53.5	48.4	45.5	45.5
Total Emissions	**6,175.2**		**7,204.2**	**7,159.3**	**7,252.8**	**7,048.3**	**6,608.3**	**6,821.8**
Land Use, Land-Use Change, and Forestry (Sinks)	(881.8)		(1,085.9)	(1,110.4)	(1,108.2)	(1,087.5)	(1,062.6)	(1,074.7)
Net Emissions (Sources and Sinks)	**5,293.4**		**6,118.3**	**6,048.9**	**6,144.5**	**5,960.9**	**5,545.7**	**5,747.1**

See Table 2-14 for more detailed data.

Figure ES-14: Emissions with Electricity Distributed to Economic Sectors

[BEGIN BOX]

Box ES- 2: Recent Trends in Various U.S. Greenhouse Gas Emissions-Related Data

Total emissions can be compared to other economic and social indices to highlight changes over time. These comparisons include: (1) emissions per unit of aggregate energy consumption, because energy-related activities are the largest sources of emissions; (2) emissions per unit of fossil fuel consumption, because almost all energy-related emissions involve the combustion of fossil fuels; (3) emissions per unit of electricity consumption, because the electric power industry—utilities and nonutilities combined—was the largest source of U.S. greenhouse gas emissions in 2010; (4) emissions per unit of total gross domestic product as a measure of national economic activity; and (5) emissions per capita.

Table ES-9 provides data on various statistics related to U.S. greenhouse gas emissions normalized to 1990 as a baseline year. Greenhouse gas emissions in the United States have grown at an average annual rate of 0.5 percent since 1990. This rate is slightly slower than that for total energy and for fossil fuel consumption, and much slower than that for electricity consumption, overall gross domestic product and national population (see Figure ES-15).

Table ES-9: Recent Trends in Various U.S. Data (Index 1990 = 100)

Variable	**1990**		**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**Growth Rate**[a]
GDP[b]	100		157	161	165	164	158	163	2.5%
Electricity Consumption[c]	100		134	135	137	136	131	137	1.6%
Fossil Fuel Consumption[c]	100		119	117	119	116	109	113	0.6%
Energy Consumption[c]	100		119	118	121	119	113	117	0.8%
Population[d]	100		118	120	121	122	123	123	1.1%
Greenhouse Gas Emissions[e]	100		117	116	117	114	107	110	0.5%

[a] Average annual growth rate
[b] Gross Domestic Product in chained 2005 dollars (BEA 2010)
[c] Energy content-weighted values (EIA 2010b)
[d] U.S. Census Bureau (2010)
[e] GWP-weighted values

Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product
Source: BEA (2010), U.S. Census Bureau (2010), and emission estimates in this report.

[END BOX]

Indirect Greenhouse Gases (CO, NO_x, NMVOCs, and SO_2)

The reporting requirements of the UNFCCC[18] request that information be provided on indirect greenhouse gases, which include CO, NO_x, NMVOCs, and SO_2. These gases do not have a direct global warming effect, but indirectly affect terrestrial radiation absorption by influencing the formation and destruction of tropospheric and stratospheric ozone, or, in the case of SO_2, by affecting the absorptive characteristics of the atmosphere. Additionally, some of these gases may react with other chemical compounds in the atmosphere to form compounds that are greenhouse gases.

Since 1970, the United States has published estimates of annual emissions of CO, NO_x, NMVOCs, and SO_2 (EPA 2010, EPA 2009),[19] which are regulated under the Clean Air Act. Table ES-10 shows that fuel combustion accounts for the majority of emissions of these indirect greenhouse gases. Industrial processes—such as the manufacture of chemical and allied products, metals processing, and industrial uses of solvents—are also significant sources of CO, NO_x, and NMVOCs.

Table ES-10: Emissions of NO_x, CO, NMVOCs, and SO_2 (Gg)

Gas/Activity	1990	2005	2006	2007	2008	2009	2010
NO_x	**21,705**	**15,899**	**15,039**	**14,380**	**13,545**	**11,467**	**11,467**
Mobile Fossil Fuel Combustion	10,862	9,012	8,488	7,965	7,441	6,206	6,206
Stationary Fossil Fuel Combustion	10,023	5,858	5,545	5,432	5,148	4,159	4,159
Industrial Processes	591	569	553	537	520	568	568
Oil and Gas Activities	139	321	319	318	318	393	393
Incineration of Waste	82	129	121	114	106	128	128
Agricultural Burning	8	6	7	8	8	8	8
Solvent Use	1	3	4	4	4	3	3
Waste	+	2	2	2	2	2	2
CO	**129,976**	**70,791**	**67,227**	**63,613**	**59,993**	**51,431**	**51,431**
Mobile Fossil Fuel Combustion	119,360	62,692	58,972	55,253	51,533	43,355	43,355
Stationary Fossil Fuel Combustion	5,000	4,649	4,695	4,744	4,792	4,543	4,543
Industrial Processes	4,125	1,555	1,597	1,640	1,682	1,549	1,549
Incineration of Waste	978	1,403	1,412	1,421	1,430	1,403	1,403
Agricultural Burning	268	184	233	237	270	247	247
Oil and Gas Activities	302	318	319	320	322	345	345
Waste	1	7	7	7	7	7	7
Solvent Use	5	2	2	2	2	2	2
NMVOCs	**20,930**	**13,761**	**13,594**	**13,423**	**13,254**	**9,313**	**9,313**
Mobile Fossil Fuel Combustion	10,932	6,330	6,037	5,742	5,447	4,151	4,151
Solvent Use	5,216	3,851	3,846	3,839	3,834	2,583	2,583
Industrial Processes	2,422	1,997	1,933	1,869	1,804	1,322	1,322
Stationary Fossil Fuel Combustion	912	716	918	1,120	1,321	424	424
Oil and Gas Activities	554	510	510	509	509	599	599
Incineration of Waste	222	241	238	234	230	159	159
Waste	673	114	113	111	109	76	76
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA
SO_2	**20,935**	**13,466**	**12,388**	**11,799**	**10,368**	**8,599**	**8,599**
Stationary Fossil Fuel Combustion	18,407	11,541	10,612	10,172	8,891	7,167	7,167
Industrial Processes	1,307	831	818	807	795	798	798
Mobile Fossil Fuel Combustion	793	889	750	611	472	455	455
Oil and Gas Activities	390	181	182	184	187	154	154

[18] See <http://unfccc.int/resource/docs/cop8/08.pdf>.

[19] NO_x and CO emission estimates from field burning of agricultural residues were estimated separately, and therefore not taken from EPA (2008).

Incineration of Waste	38	24	24	24	23	24	24
Waste	+	1	1	1	1	1	1
Solvent Use	+	+	+	+	+	+	+
Agricultural Burning	NA	NA	NA	NA	NA	NA	NA

Source: (EPA 2010, EPA 2009) except for estimates from field burning of agricultural residues.
NA (Not Available)
Note: Totals may not sum due to independent rounding.
+ Does not exceed 0.5 Gg.

Key Categories

The 2006 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 2006) defines a key category as a "[source or sink category] that is prioritized within the national inventory system because its estimate has a significant influence on a country's total inventory of direct greenhouse gases in terms of the absolute level of emissions, the trend in emissions, or both."[20] By definition, key categories are sources or sinks that have the greatest contribution to the absolute overall level of national emissions in any of the years covered by the time series. In addition, when an entire time series of emission estimates is prepared, a thorough investigation of key categories must also account for the influence of trends of individual source and sink categories. Finally, a qualitative evaluation of key categories should be performed, in order to capture any key categories that were not identified in either of the quantitative analyses.

Figure ES-16 presents 2010 emission estimates for the key categories as defined by a level analysis (i.e., the contribution of each source or sink category to the total inventory level). The UNFCCC reporting guidelines request that key category analyses be reported at an appropriate level of disaggregation, which may lead to source and sink category names which differ from those used elsewhere in the inventory report. For more information regarding key categories, see section 1.5 and Annex 1.

Figure ES-16: 2010 Key Categories

Quality Assurance and Quality Control (QA/QC)

The United States seeks to continually improve the quality, transparency, and credibility of the Inventory of U.S. Greenhouse Gas Emissions and Sinks. To assist in these efforts, the United States implemented a systematic approach to QA/QC. While QA/QC has always been an integral part of the U.S. national system for inventory development, the procedures followed for the current inventory have been formalized in accordance with the QA/QC plan and the UNFCCC reporting guidelines.

Uncertainty Analysis of Emission Estimates

While the current U.S. emissions inventory provides a solid foundation for the development of a more detailed and comprehensive national inventory, there are uncertainties associated with the emission estimates. Some of the current estimates, such as those for CO_2 emissions from energy-related activities and cement processing, are considered to have low uncertainties. For some other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated increases the uncertainty associated with the estimates presented. Acquiring a better understanding of the uncertainty associated with inventory estimates is an important step in helping to prioritize future work and improve the overall quality of the Inventory. Recognizing the benefit of conducting an uncertainty analysis, the UNFCCC reporting guidelines follow the recommendations of the IPCC Good Practice Guidance (IPCC 2000) and require that countries provide single estimates of uncertainty for source and sink categories.

Currently, a qualitative discussion of uncertainty is presented for all source and sink categories. Within the

[20] See Chapter 7 "Methodological Choice and Recalculation" in IPCC (2000). <http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm>

discussion of each emission source, specific factors affecting the uncertainty surrounding the estimates are discussed. Most sources also contain a quantitative uncertainty assessment, in accordance with UNFCCC reporting guidelines.

[BEGIN BOX]

Box ES- 3: Recalculations of Inventory Estimates

Each year, emission and sink estimates are recalculated and revised for all years in the Inventory of U.S. Greenhouse Gas Emissions and Sinks, as attempts are made to improve both the analyses themselves, through the use of better methods or data, and the overall usefulness of the report. In this effort, the United States follows the 2006 IPCC Guidelines (IPCC 2006), which states, “Both methodological changes and refinements over time are an essential part of improving inventory quality. It is good practice to change or refine methods” when: available data have changed; the previously used method is not consistent with the IPCC guidelines for that category; a category has become key; the previously used method is insufficient to reflect mitigation activities in a transparent manner; the capacity for inventory preparation has increased; new inventory methods become available; and for correction of errors.” In general, recalculations are made to the U.S. greenhouse gas emission estimates either to incorporate new methodologies or, most commonly, to update recent historical data.

In each Inventory report, the results of all methodology changes and historical data updates are presented in the "Recalculations and Improvements" chapter; detailed descriptions of each recalculation are contained within each source's description contained in the report, if applicable. In general, when methodological changes have been implemented, the entire time series (in the case of the most recent inventory report, 1990 through 2010) has been recalculated to reflect the change, per the 2006 IPCC Guidelines (IPCC 2006). Changes in historical data are generally the result of changes in statistical data supplied by other agencies. References for the data are provided for additional information.

[END BOX]

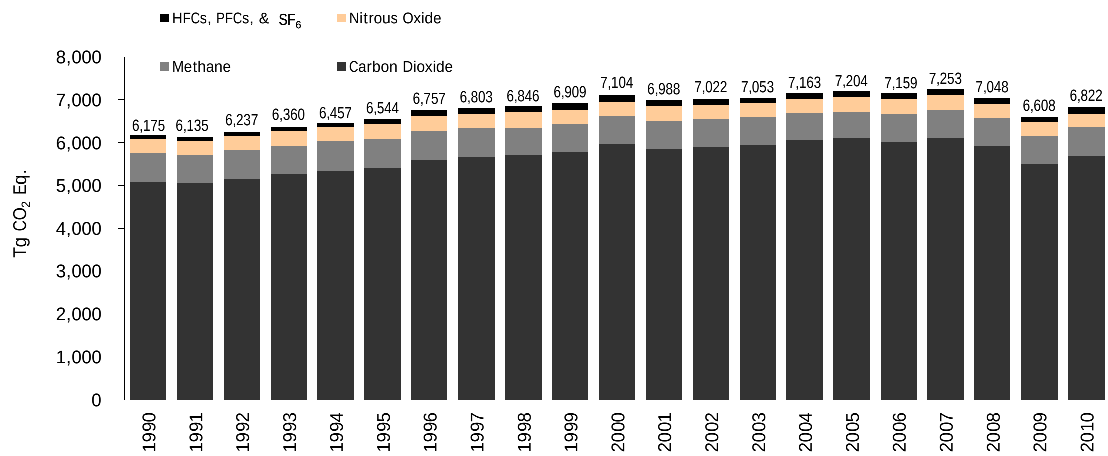


Figure ES-1: U.S. Greenhouse Gas Emissions by Gas

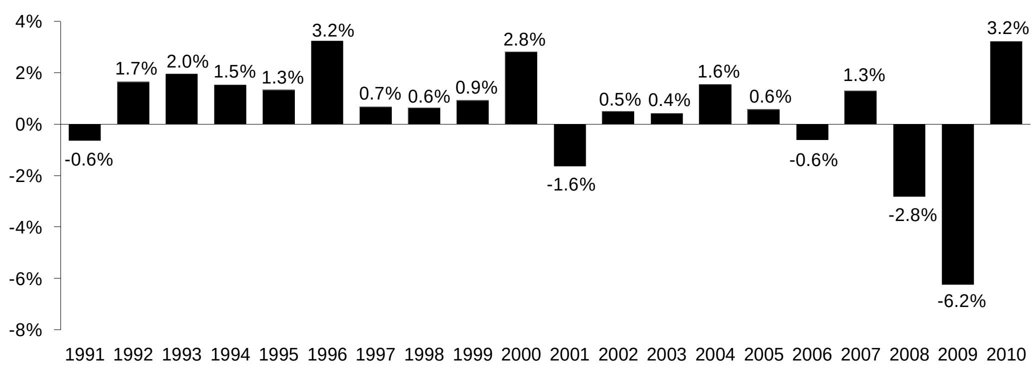


Figure ES-2: Annual Percent Change in U.S. Greenhouse Gas Emissions

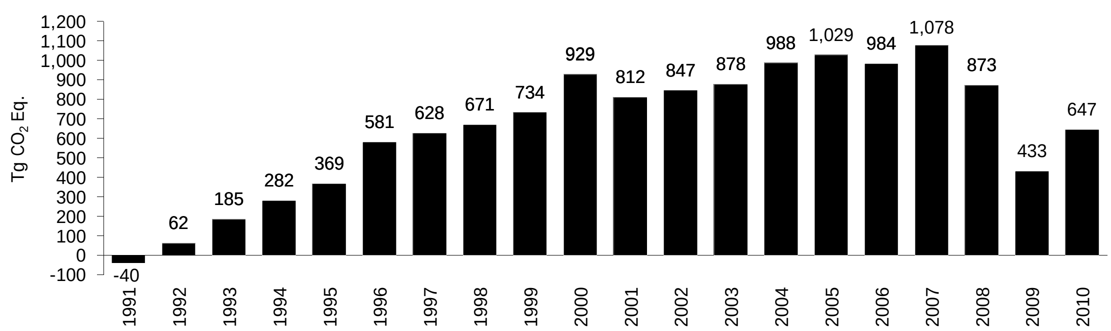


Figure ES-3: Cumulative Change in Annual U.S. Greenhouse Gas Emissions Relative to 1990

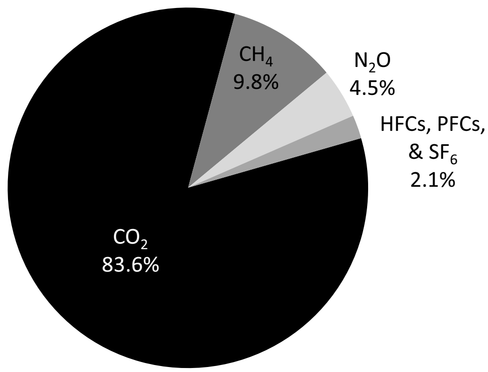


Figure ES-4: 2010 Greenhouse Gas Emissions by Gas (percents based on Tg CO_2 Eq.)

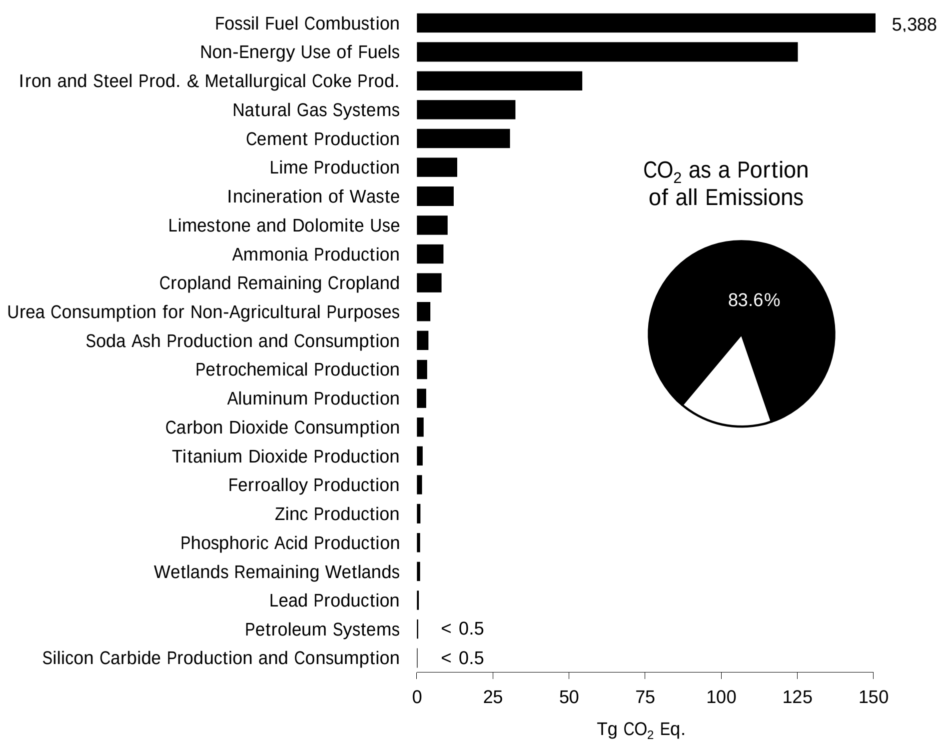


Figure ES-5: 2010 Sources of CO_2 Emissions

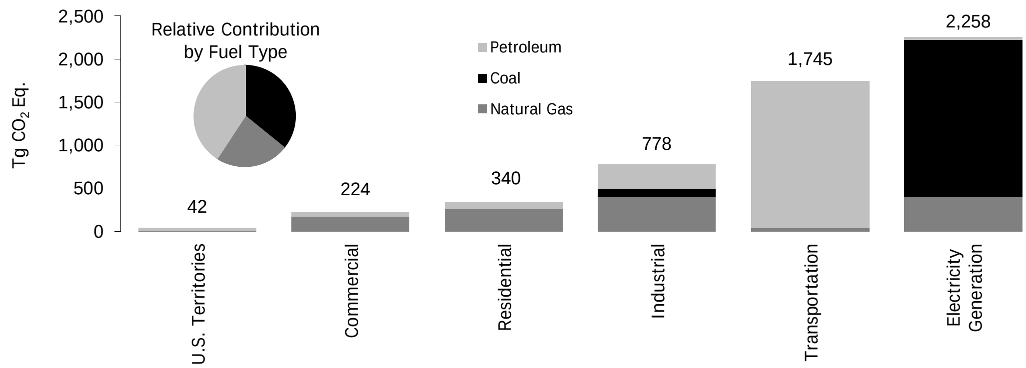


Figure ES-6: 2010 CO_2 Emissions from Fossil Fuel Combustion by Sector and Fuel Type

Note: Electricity generation also includes emissions of less than 0.5 Tg CO_2 Eq. from geothermal-based electricity generation.

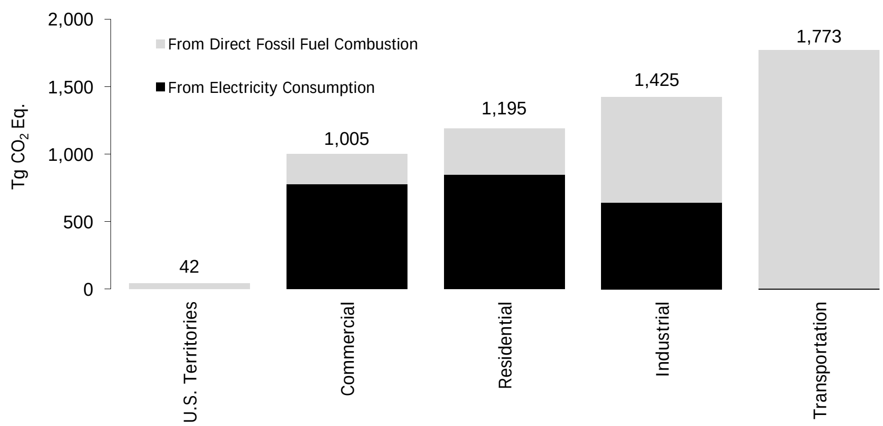


Figure ES-7: 2010 End-Use Sector Emissions of CO_2, CH_4, and N_2O from Fossil Fuel Combustion

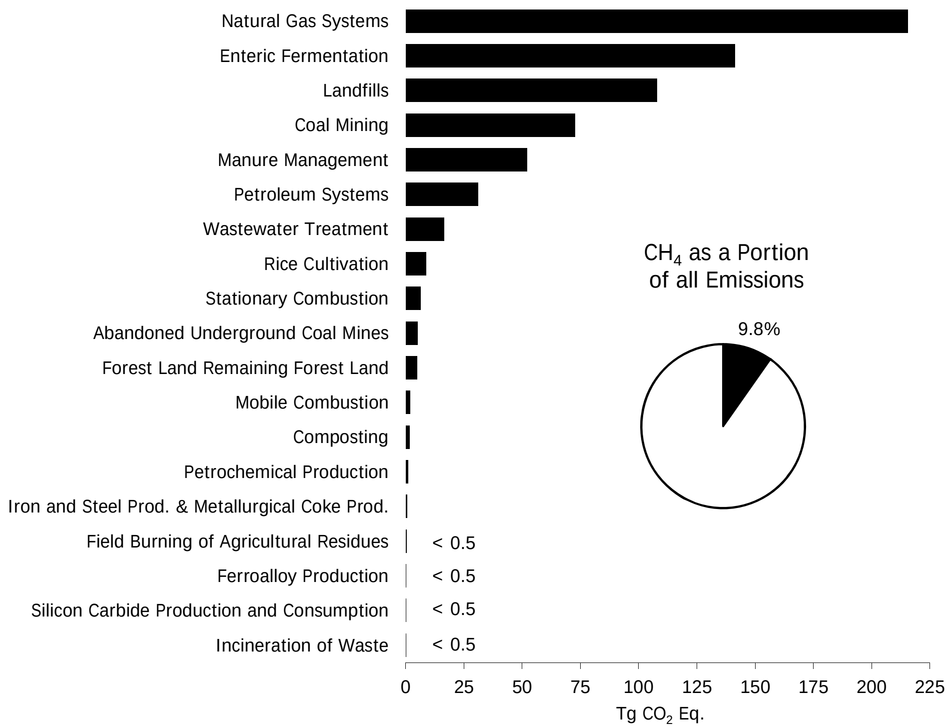


Figure ES-8: 2010 Sources of CH_4 Emissions

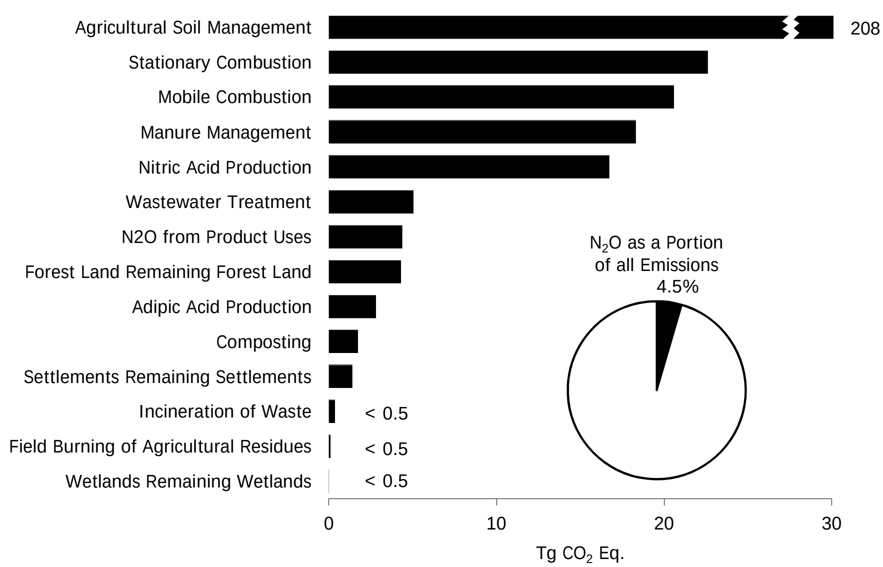


Figure ES-9: 2010 Sources of N_2O Emissions

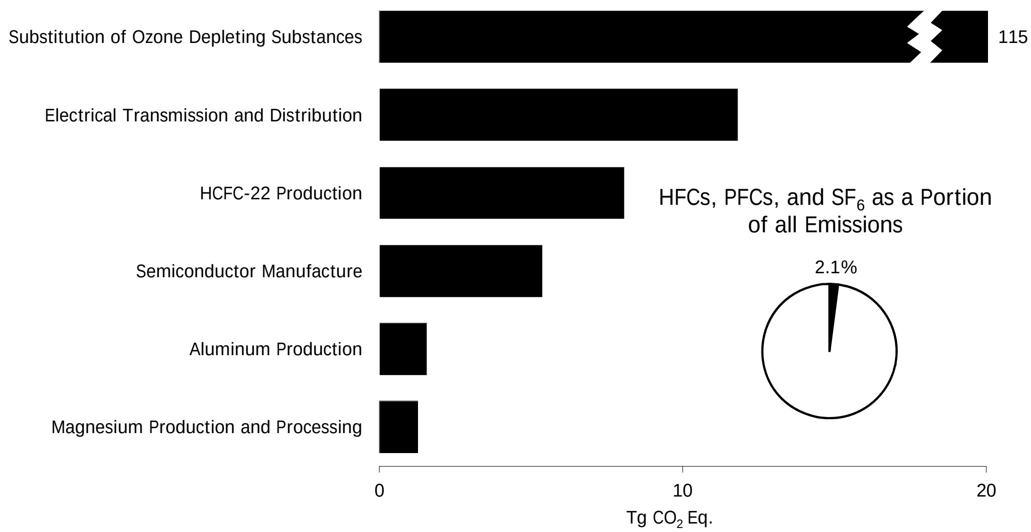
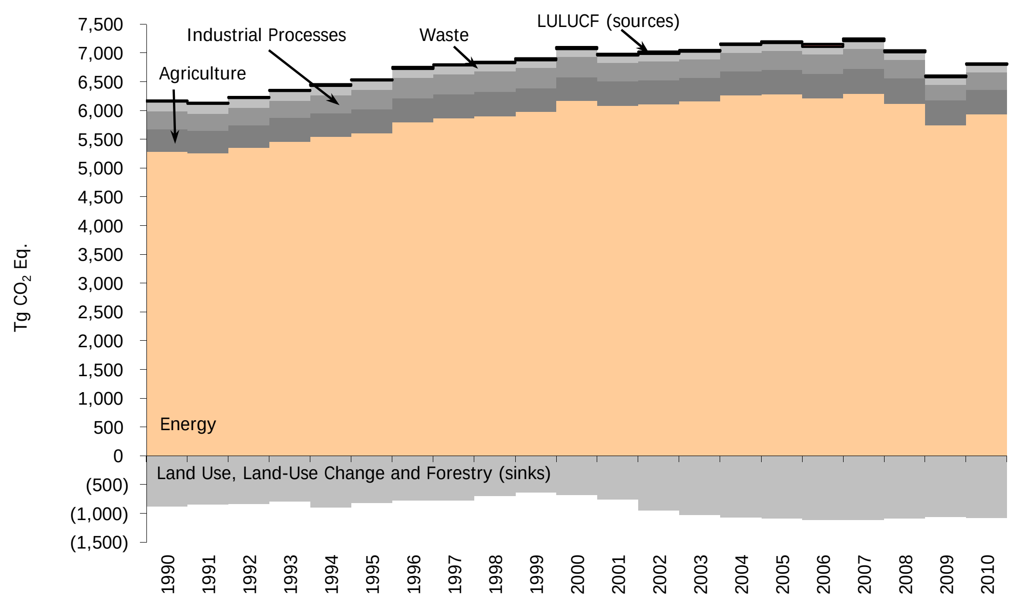


Figure ES-10: 2010 Sources of HFCs, PFCs, and SF_6 Emissions



Note: Relatively smaller amounts of GWP-weighted emissions are also emitted from the Solvent and Other Product Use sectors

Figure ES-11: U.S. Greenhouse Gas Emissions and Sinks by Chapter/IPCC Sector

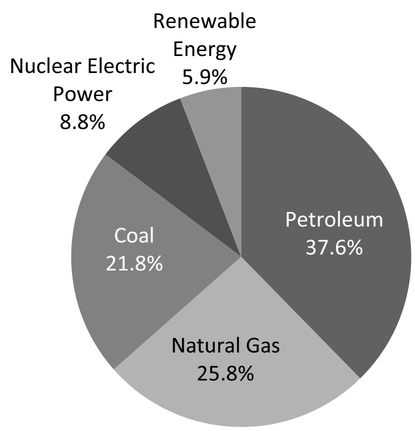


Figure ES-12: 2010 U.S. Energy Consumption by Energy Source

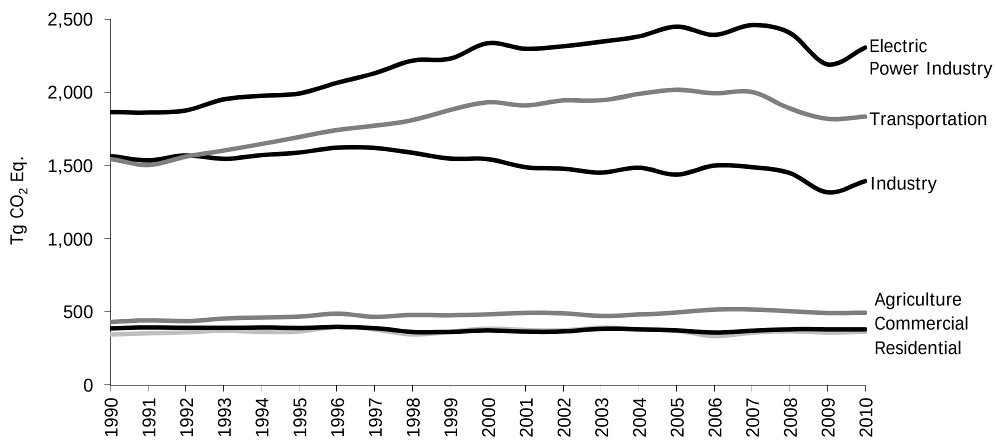


Figure ES-13: Emissions Allocated to Economic Sectors
Note: Does not include U.S. Territories.

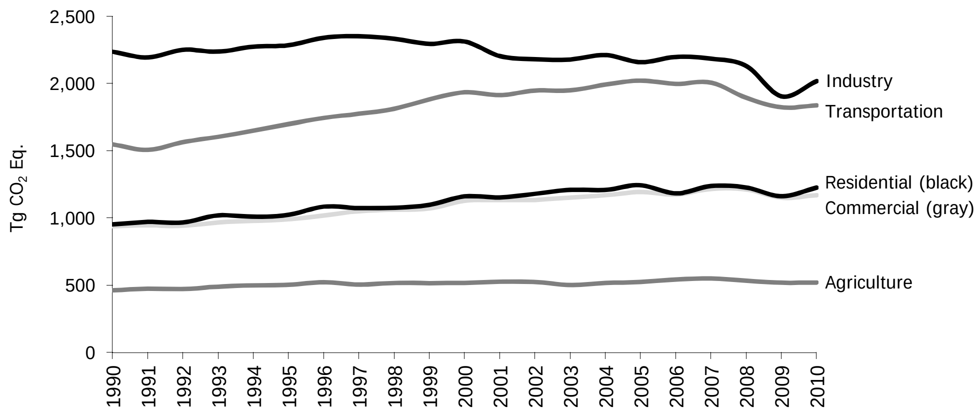


Figure ES-14: Emissions with Electricity Distributed to Economic Sectors

Note: Does not include U.S. Territories.

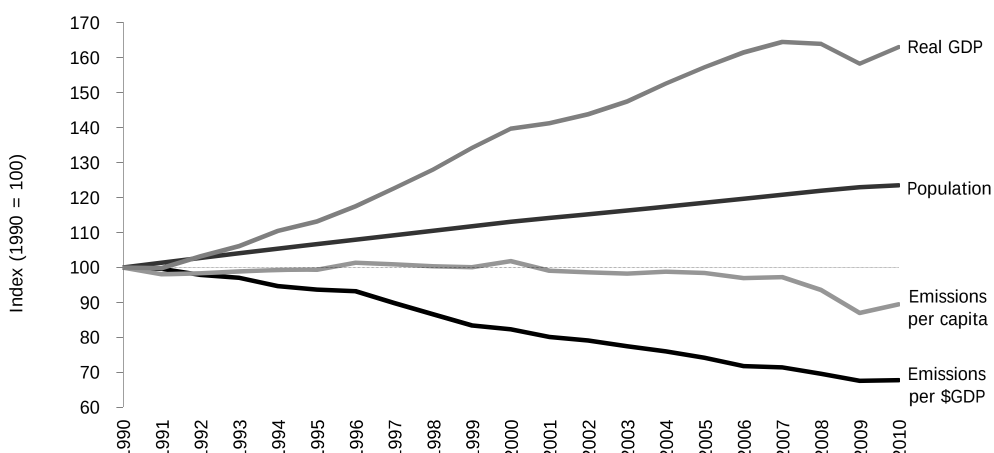


Figure ES-15: U.S. Greenhouse Gas Emissions Per Capita and Per Dollar of Gross Domestic Product

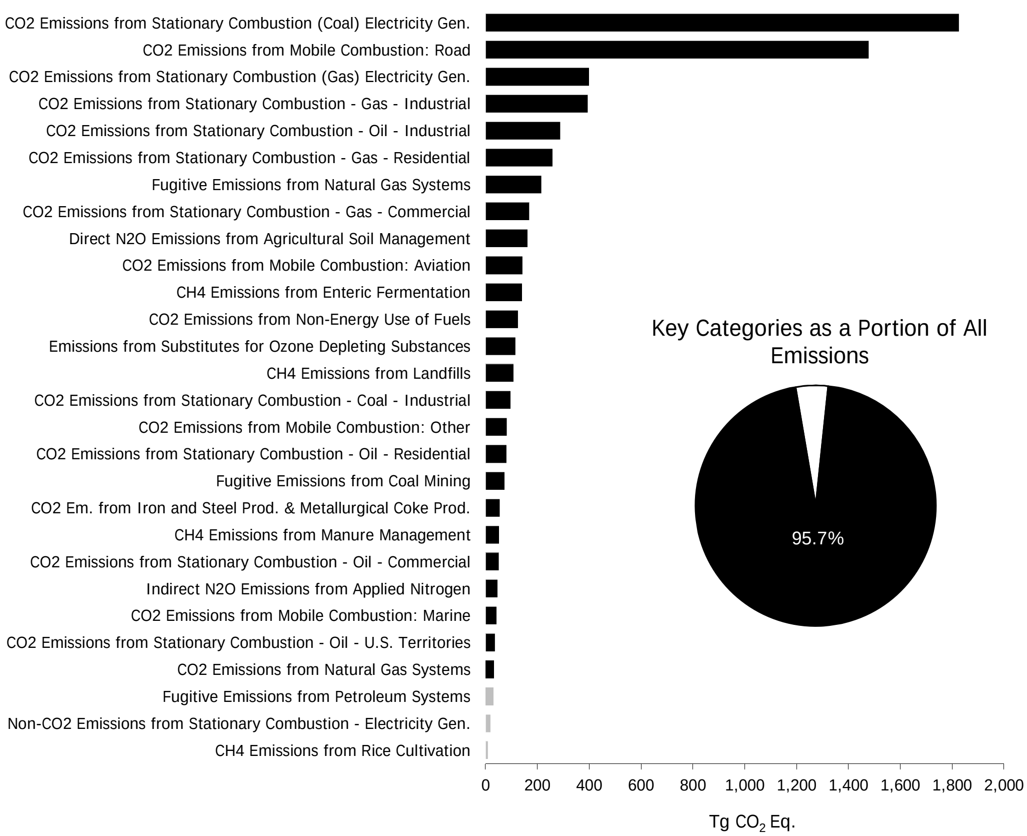


Figure ES-16: 2010 Key Categories

Notes: For a complete discussion of the key category analysis, see Annex 1.
Black bars indicate a Tier 1 level assessment key category.
Gray bars indicate a Tier 2 level assessment key category.

Comparing Life-Cycle Greenhouse Gas Emissions from Natural Gas and Coal

August 25, 2011

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Executive Summary

— **Research conclusion and key messages—natural gas offers greenhouse gas advantages over coal**: Natural gas has been widely discussed as a less carbon-intensive alternative to coal as a power sector fuel. In April 2011, the U.S. Environmental Protection Agency released revised methodologies for estimating fugitive methane emissions from natural gas systems. These revisions mostly affected the production component of the natural gas value chain (namely, gas well cleanups), causing a very substantial increase in the methane emissions estimate from U.S. natural gas systems.[1,2] This large increase in the upstream component of the natural gas value chain caused some to question the GHG advantage of gas versus coal over the entire life-cycle from source to use. As a result of this renewed attention, while it remains unambiguous that natural gas has a lower carbon content per unit of energy than coal does, several recent bottom-up studies have questioned whether natural gas retains its greenhouse gas advantage when the entire life cycles of both fuels are considered.[3]

Particular scrutiny has focused on shale formations, which are the United States' fastest growing marginal supply source of natural gas. Several recent bottom-up life-cycle studies have found the production of a unit of shale gas to be more GHG-intensive than that of conventional natural gas.[4] Consequently, if the upstream emissions associated with shale gas production are not mitigated, a growing share of shale gas would increase the average life-cycle greenhouse gas footprint of the total U.S. natural gas supply.

Applying the latest emission factors from the EPA's 2011 upward revisions, our top-down life-cycle analysis

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[1] *EPA, Inventory of U.S. Greenhouse Gas Emissions And Sinks:1990 – 2009, U.S. EPA, EPA 430-R-11-005,* *http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Complete_Report.pdf, cited in Mark Fulton, et al., "Comparing Life Cycle Greenhouse Gas Emissions from Natural Gas and Coal," 14 March 2011, available at* *http://www.dbcca.com/dbcca/EN/_media/Comparing_Life_Cycle_Greenhouse_Gas.pdf.*

[2] *Note: For example, the EPA's estimates of methane emissions from U.S. natural gas systems in the base year of 2008 increased 120 percent between the 2010 and 2011 versions of their Inventory of U.S. Greenhouse Gas Emissions and Sinks.*

[3] *The two approaches for an LCA study are bottom-up and top-down. A bottom-up study analyzes the emissions from an individual representative or prototype process or facility and calculates the emissions of that specific part of the value chain. It then combines each step of the value chain to compute the total lifecycle emissions from source to use. A top-down study, in contrast, looks at the total national emissions for a particular use or sector and depicts the national average life-cycle emissions for each discrete part of source to use for that sector to arrive at an aggregate estimate. Each approach has benefits and limitations. The bottom-up approach provides insights into the emissions for a particular process or fuel source, but also depicts only that specific process or source. The top-down approach represents the emissions across an entire sector but does not focus on specific processes or technologies. Some of the data sources for a top-down analysis may be built up from bottom-up sources, but the top-down analysis still yields a more general result.*

[4] *Robert W. Howarth, et al., "Methane and the greenhouse-gas footprint of natural gas from shale formations,"* Climatic Change *(2011); Timothy J. Skone, National Energy Technology Laboratory (NETL), "Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States," presentation (Ithaca, NY: 12 May 2011; revised 23 May 2011); Mohan Jiang, et al., "Life cycle greenhouse gas emissions of Marcellus Shale gas,"* Environmental Research Letters *6 (3), 5 August 2011.*

(LCA)[5] finds that the EPA's new methodology increases the life-cycle emissions estimate of natural gas-fired electricity for the baseline year of 2008 by about 11 percent compared with its 2010 methodology. But even with these adjustments, we conclude that **on average, U.S. natural gas-fired electricity generation still emitted 47 percent less GHGs than coal from source to use using the IPCC's 100-year global warming potential for methane of 25**. This figure is consistent with the findings of all but one of the recent life-cycle analyses that we reviewed.

While our LCA finds that the EPA's updated estimates of methane emissions from natural gas systems do not undercut the greenhouse gas advantage of natural gas over coal, methane is nevertheless of concern as a GHG, and requires further attention. In its recent report on improving the safety of hydraulic fracturing, the U.S. Secretary of Energy's Advisory Board's Subcommittee on Shale Gas Production recommended that immediate efforts be launched to gather improved methane emissions data from shale gas operations.[6] In the meantime, methane emissions during the production, processing, transport, storage, and distribution of all forms of natural gas can be mitigated immediately using a range of existing technologies and best practices, many of which have payback times of three years or less.[7] Such capture potential presents a commercial and investment opportunity that would further improve the life-cycle GHG footprint of natural gas. Although the adoption of these practices has been largely voluntary to date, the EPA proposed new air quality rules in July 2011 that would require the industry to mitigate many of the methane emissions associated with natural gas development, and in particular with shale gas development.[8]

Our research methodology: This paper seeks to assess the current state of knowledge about the average greenhouse gas footprints of average coal and natural gas-fired electricity in the system today, how the growing share of natural gas production from shale formations could change this greenhouse gas footprint at the margin, and what the findings imply for policymakers, investors and the environment. In the first part of the paper, we examine recent bottom-up life-cycle analyses to provide context for our top-down analysis. These bottom-up analyses' estimation of the life-cycle GHG footprint of shale gas provides information about the potential marginal GHG impact of shale's rising share in the U.S. natural gas supply, as well as which emissions streams can be targeted for the greatest GHG mitigation. In the second part of the paper, we conduct our own top-down life-cycle analysis of GHGs from natural-gas and coal-fired electricity in 2008 using the EPA's revised 2011 estimates as well as other publically available government data. We make three key adjustments to the data sets in order to calculate a more accurate and meaningful national level inventory: we include: 1) emissions associated with net natural gas and coal imports; 2) natural gas produced as a byproduct of petroleum production, and 3) the share of natural gas that passes through distribution pipelines before reaching power plants. This top-down analysis examines the implications of the EPA's revised (2011) estimates for the current and future average greenhouse gas footprint of U.S. natural gas-fired electricity and its comparison with coal-fired electricity.

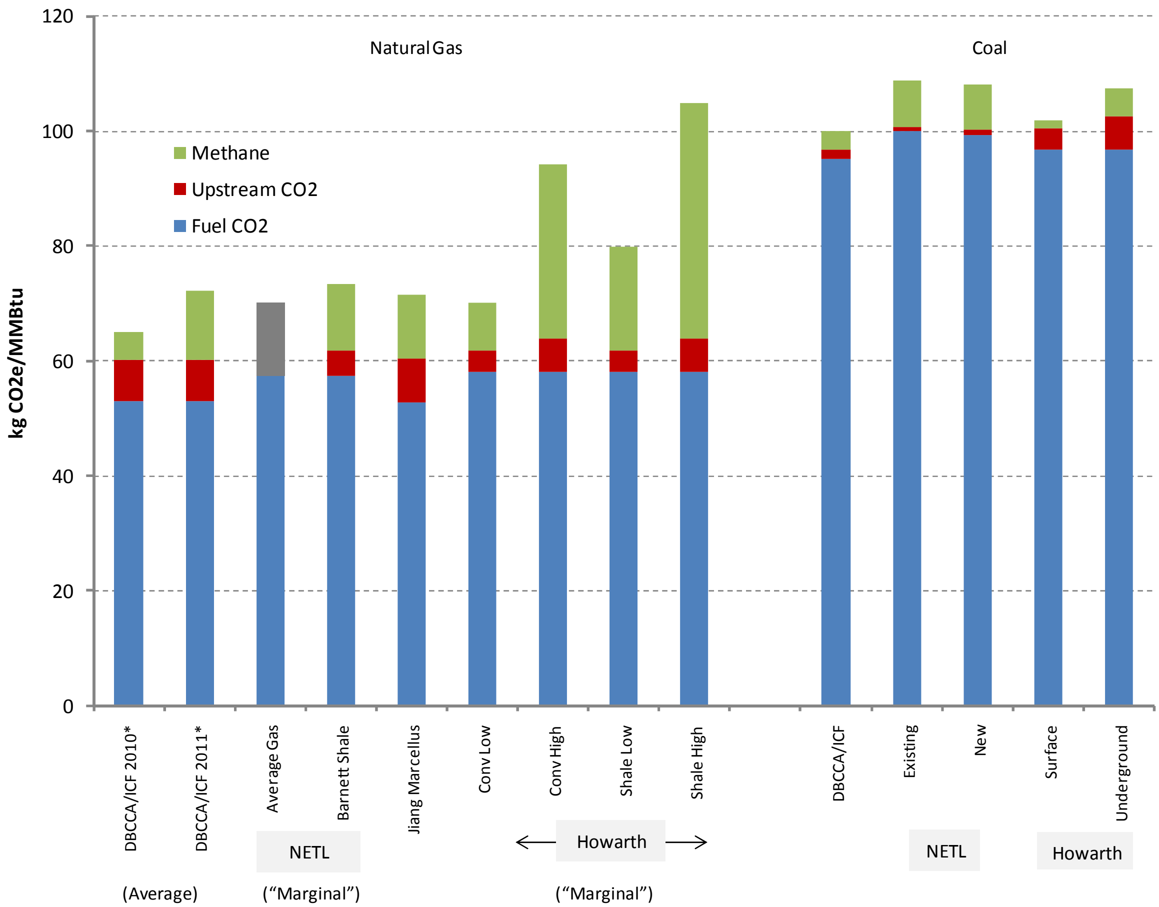
GWP and power plant efficiency matter: Global warming potentials (GWPs) are used to convert the volumes of greenhouse gases with different heat-trapping properties into units of carbon dioxide-equivalent (CO_2e) for the purpose of examining the relative climate forcing impacts of different volumes of gas over discrete time periods. The Intergovernmental Panel on Climate Change's (IPCC) most recent assessment, published in 2007, estimates methane's GWP to be 25 times greater than that of carbon dioxide over a 100-year timeframe and 72 times greater than that of carbon dioxide over a 20-year timeframe.[9] Unless

[5] "Life-cycle analysis" (LCA) is a generic term, and the methodology and scope of analysis can vary significantly across studies. Our analysis assesses GHGs during the production, processing, transport, and use of natural gas and coal to generate electricity. Some studies include not only the direct and indirect emissions from the plant or factory that provides or makes a certain product, but also the emissions associated with the inputs used to manufacture and create the production facilities themselves. This study does not address the manufacturing, construction, or decommissioning of the equipment used in energy production. As with any study, the certainty of conclusions drawn from an LCA can only be as strong as the underlying data.
[6] U.S. Department of Energy, Secretary of Energy Advisory Board, Shale Gas Production Subcommittee, 90-Day Report, 18 August 2011, http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf.
[7] Numerous technologies and best practices to capture methane that would otherwise be vented during natural gas production, processing, transport, or distribution have been detailed by the U.S. EPA's voluntary Natural Gas STAR Program. Many of these have payback periods under 3 years. U.S. Environmental Protection Agency, Natural Gas STAR Program, "Recommended Technologies and Practices," available at http://www.epa.gov/gasstar/tools/recommended.html, viewed 29 July 2011.
[8] EPA, "Oil and Natural Gas Air Pollution Standards," http://epa.gov/airquality/oilandgas/, viewed 18 August 2011.
[9] Piers Forster et al., 2007: Changes in Atmospheric Constituents and in Radiative Forcing. In: Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Solomon, S., D.

otherwise specified, our analysis uses the 100-year GWP of 25 but we also calculate life-cycle emissions using a range of methane GWPs that have been proposed—including 72 and 105—in Appendix B of this report in order to show the sensitivities of the outputs to GWP. The choice of GWP does impact the relative GHG footprint between coal and gas. However, the life-cycle GHG footprint of gas is lower than coal under all GWPs tested, with the smallest difference calculated using a GWP of 105, where the GHG emissions in kilograms CO_2 per megawatt-hour of electricity generated (kg CO_2e/MWh) are 27 percent less than those of coal-fired generation.

In addition, assumed power plant efficiencies also have a measurable impact on the life-cycle comparison between natural gas and coal-fired electricity generation. Unless otherwise specified, our analysis uses average U.S. heat rates for coal and natural gas plants for the existing capital stock: 11,044 Btu/kWh (31% efficiency) for coal and 8,044 Btu/kWh (41% efficiency) for natural gas plants. We also calculate life-cycle emissions using heat rate estimates for new U.S. natural gas and coal plants in Appendix A (Exhibit A-11).

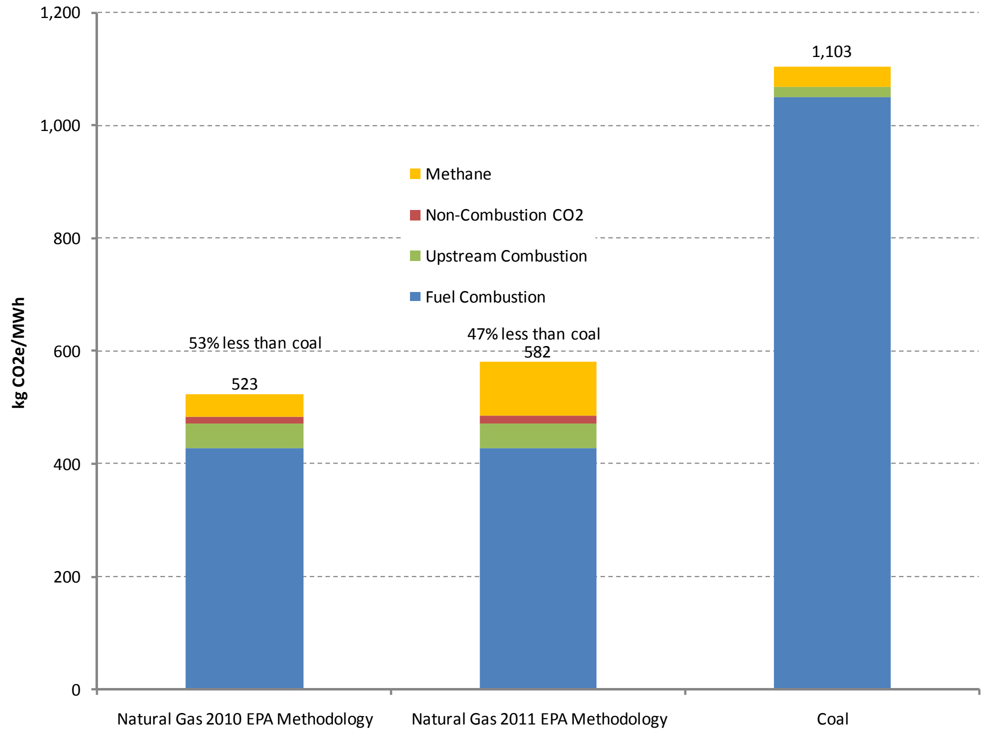
ES-1. Comparison of Recent Life-Cycle Assessments



Source: DBCCA Analysis 2011; NETL 2011; Jiang 2011; Howarth 2011. Note: NETL Average Gas study includes bar shaded grey due to inability to segregate upstream CO2 and methane values, which were both accounted for in the study. See page 10 for more information. *2011 EPA methodology compared to 2010.

Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M.Tignor and H.L. Miller (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA., p. 212.

ES-2. Average U.S. Life-Cycle GHG Emissions from Coal and Gas Electricity Generation, 2008
Comparing EPA 2010 Methodology with EPA 2011 Methodology



Source: DBCCA Analysis 2011. See pages 19 and 20 for more details.

Introduction and Key Exhibits

— **Our methodology:** Our top-down analysis addresses the emissions of three GHGs emitted during the production, processing, storage, transmission, distribution, and use of natural gas and coal in power plants:

1. Carbon dioxide (CO_2);
2. Methane (CH_4) and;
3. Nitrous oxide (N_2O)

Carbon dioxide is a product of fossil fuel combustion and is also released during some stages of gas processing. Methane, the primary component of natural gas (roughly 98 percent of pipeline-quality gas), is a potent GHG.[10] It is released at many points during the life-cycle of natural gas production and use and also during coal mining, and it is an important component of the life-cycle emissions of both fuels, but especially of natural gas. Methane emissions can be categorized as "fugitive" or "vented" emissions. Fugitive emissions include unintentional "leaks" from poorly sealed valves, flanges, meters, and other equipment.[11] Venting is the intentional release of methane as part of the operating procedure for a particular process. For example, when a compressor or a pipeline is taken out of service for repair, the compressed gas in the equipment may be released. There are a variety of venting operations associated with natural gas production that account for the majority of methane emissions in the natural gas sector. Because the amount of fugitive and vented methane is highly dependent on the practices and technologies that are used, the amount of methane emitted can vary significantly by facility and/or the stripping and "clean up" process employed. Although small amounts of methane and nitrous oxide are also emitted during fossil fuel combustion, carbon dioxide is by far the largest greenhouse gas product. In this paper, because the amounts of methane and nitrous oxide are such a small fraction of the total combustion-related emissions, we include them together with CO_2 on tables and figures under the heading "combustion."[12]

— **Reader roadmap:** In the section that follows, we start with a review of recent LCA studies. These studies have attempted to measure the life-cycle GHG footprint of shale gas and are valuable from our perspective in framing the marginal impact of shale gas on the GHG intensity of average natural gas-fired electricity. We then build up to a full comparison of the life-cycle emissions between natural gas and coal-fired electricity generation at a national level based on different assumptions and data adjustments in order to assess the impact that the EPA 2011 methodology change on GHG inventory has on the LCA comparison between average U.S. natural gas- and coal-fired electricity generation. We use emissions data for 2008 as a comparable baseline to show the impact of the 2010 and 2011 changes in EPA methane methodology to the life-cycle GHG emissions comparison between coal and natural gas in that year. (Note the Global Warming Potential used throughout this analysis is 25 unless otherwise noted – see Appendix B.) This overview provides a roadmap to follow the logic of our analytic approach.

- **Step 1:** In Exhibit 2, page 10 we compare the most recent bottom-up studies of the LCA of gas from hydraulically fractured shale formations versus coal as a starting point;

- **Step 2:** In Exhibit 4, page 13 we list the baseline EPA data for 2008 on the upstream natural gas emissions expressed as million metric tons of CO_2 equivalent ($MMTCO_2e$);

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[10] Methane remains in the atmosphere for ~9-15 years, compared to 100+ years for CO_2; Methane, however, is much more effective at trapping heat in the atmosphere than CO_2, particularly over 20 year time periods (Please see Appendix B at the end of this report).
[11] Of critical importance, such leaks can be fairly easily mitigated from a technical perspective at reasonable cost, which means that there is scope for improvement.
[12] The EPA Greenhouse Gas Reporting Rule gives CH_4 and N_2O emission factors for the combustion of different fossil fuels. For CH_4, emission factors of 0.001 kg/MMBtu of natural gas and 0.011 kg/MMBtu of coal were used. For N2O, emission factors of 0.0001 kg/MMBtu of natural gas and 0.0016 kg/MMBtu of coal were used. The emission factors are in table C-2, page 38 of Subpart C of the rule. (Please see: http://www.epa.gov/climatechange/emissions/downloads09/GHG-MRR-FinalRule.pdf)
These were then adjusted using GWPs for CH_4 and N_2O to obtain emissions factors in kg CO_2e/MMBtu. Unless otherwise noted in the paper, 100-year GWP values from the IPCC's Fourth Assessment Report (2007) were used: 25 for CH_4 and 298 for N_2O. Using these values, the total GHGs emitted during the combustion of natural gas are 53.07 kg CO_2e/MMBtu (99.90% CO_2, 0.05% CH_4, 0.06% N_2O) and the total GHGs emitted during the combustion of coal are 95.13 kg CO_2e/MMBtu (99.21% CO_2, 0.29% CH_4, 0.50% N_2O).

- **Step 3:** In Exhibit 5, page 14, we adjust these baseline estimates to account for additional factors such as natural gas imports, methane emissions from other parts of the industry and other types of emissions associated with natural gas production;

- **Step 4:** In Exhibit 6, page 15, we combine our adjusted upstream and downstream natural gas emissions to derive a normalized life-cycle emissions expressed as kg/MMBTU (volume of greenhouse gases per unit of energy value delivered to the power plant) and compare with coal on an equivalent carbon-dioxide equivalent basis for the electricity sector using 2008 data and the EPA's 2011 methane emissions methodology;

- **Step 5:** In Exhibit 7, page 15, we rerun Step 3 above for 2008 emissions but using the EPA 2010 methane emission methodology from the EPA in order to show the impact of the revisions pre-combustion in kg CO_2e/MMBtu;

- **Step 6:** In Exhibit 8, page 15, we use EPA's 2011 methane emissions methodology to calculate emissions for 2009, the most recent year data available;

- **Step 7:** In Exhibit 10, page 17, we adjust upstream emissions from coal into standard volume units of MMTCO_2e in order to assess the emissions associated with the production and transportation from the mine to the power plant using 2008 data for an apples-to-apples comparison with gas;

- **Step 8:** In Exhibit 11, page 17, we then normalize these upstream coal emission factors into kg CO_2e/MMBtu (emission volume per unit of energy delivered);

- **Step 9:** In Exhibit 12, page 19, we compare the life-cycle emissions of natural gas and coal delivered to the power plant in kg CO_2e/MMMBtu using 2008 data but adjusted for both 2010 and 2011 EPA methane emission factor methodologies for natural-gas to show the impact of EPA's revisions;

- **Step 10:** In Exhibit 13, page 20, we show the LCA in terms of emissions per megawatt-hour of electricity generated from gas and coal using the national average power plant efficiencies for 2008. The life-cycle emissions for gas are 11 percent higher using the updated methodology. The Exhibit shows a six percentage point change with gas producing 47 percent lower emissions than coal using EPA's 2011 methane methodology compared to producing 53 percent lower emissions using EPA 2010 methane methodology based on a 100-year GWP value for methane of 25.

- **Sensitivity Analysis Using Alternative GWPs:** In Appendix B, we show the sensitivities of our LCA to different GWPs.

Overview of Natural Gas Systems and Emission Sources

Between its 2010 and 2011 editions of the Inventory, the EPA significantly revised its methodology for estimating GHG emissions from natural gas systems, resulting in an estimate of methane emissions from Natural Gas Systems in 2008 that was 120 percent higher than its previous estimate. Up until 2010, the Inventory had relied extensively upon emission and activity factors developed in a study by the EPA and the Gas Research Institute in 1996. For the 2011 Inventory, the EPA modified its treatment of two emissions sources that had not been widely used at the time of the 1996 study, but have since become common: gas well completions and workovers with hydraulic fracturing. It also significantly modified the estimation methodology for emissions from gas well cleanups, condensate storage tanks, and centrifugal compressors.

The bulk of the EPA's recent upward revisions of natural gas emissions estimates are related to the production part of the gas value chain. The largest component of the increase is due to revised estimates of methane released from liquids unloading: In some natural gas wells, downhole gas pressure is used to blow reservoir liquids that have accumulated at the bottom of the well to the surface.[13] The revisions also include an increase in the share of gas that is produced from hydraulically fractured shale gas wells and a change in the assumption as to how much of the flow-back emissions are flared. Previously, the EPA assumed that 100 percent of these emissions were flared or captured for sale. The new estimate assumes that approximately one third are flared and another third are captured through "reduced emission completions." Both of these are based on estimated counts of equipment and facility and associated emission factors.

These revisions have caused some to question whether replacing coal with natural gas would actually reduce GHGs, when emissions over the entire life cycles of both fuels are taken into account. Addressing these questions requires an understanding of:

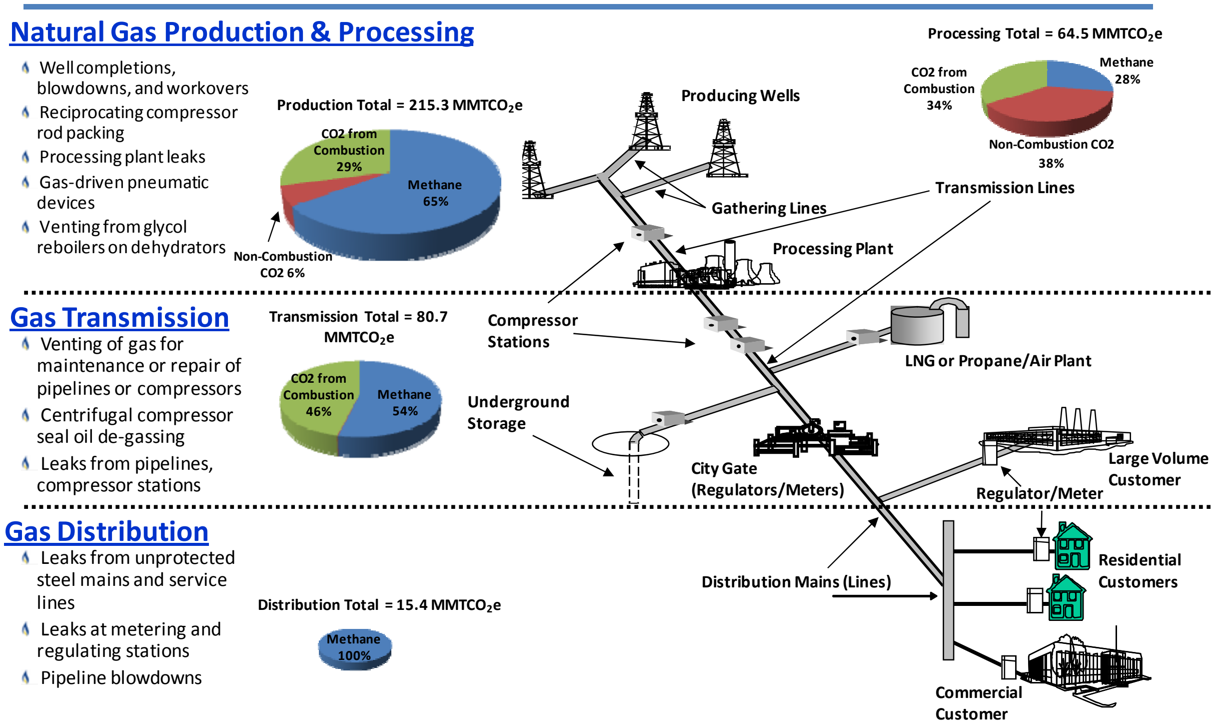
1) The best available data on emissions throughout the life cycles of natural gas and coal;
2) The specific sources and magnitudes of GHG emissions streams for natural gas produced from shale versus conventional formations; and
3) How an increase in the contribution of shale gas to the U.S. natural gas supply might impact the overall life-cycle GHG footprint of natural gas-fired electricity in the future as the marginal skews the average.

Up until the past few years, most of the U.S. natural gas supply came from the Gulf of Mexico and from western and southwestern states. More recently, mid-continental shale plays have been a growing source of supply. Natural gas is produced along with oil in most oil wells (as "associated gas") and also in gas wells that do not produce oil (as "non-associated gas").

Exhibit 1 illustrates the primary sources of GHG emissions during natural gas production, processing, transmission and distribution. The equipment for drilling both oil and gas wells is powered primarily by large diesel engines and also includes a variety of diesel-fueled mobile equipment. Raw natural gas is vented at various points during production and processing prior to compression and transport by pipeline. In some cases, the gas may be flared rather than vented to maintain safety and to relieve over-pressuring within different parts of the gas extraction and delivery system. Flaring produces CO_2, a less potent GHG than methane.

[13] The technique of blowing out liquids is most frequently used in vertical wells containing "wet" or liquids-rich gas. It is being replaced by many producers with "plunger lifts" that remove liquids with much less gas release. In many shale wells, a technique is used where liquids are allowed to collect in a side section of the well and removed with a pump. EPA, Natural GAS Star, "Lessons Learned: Installing Plunger Lift Systems in Gas Wells," October 2006, available at http://www.epa.gov/gasstar/documents/ll_plungerlift.pdf.

Exhibit 1. Natural Gas Industry Processes and Methane Emission Sources



Sources: American Gas Association; EPA Natural Gas STAR Program, DBCCA analysis, 2011.

The recent focus of new natural gas development has been shale gas, which currently represents about 14 percent of U.S. domestic production but is expected to reach 45 percent or more by 2035.[14] Most gas-bearing shale formations lie 8,000 to 12,000 feet below the surface and are tapped by drilling down from the surface and then horizontally through the target formation, with lateral drills extending anywhere from 3,000 to 10,000 feet. After drilling is complete, operators hydraulically fracture the shale, pumping fluids at high pressure into the well to stimulate the production of the gas trapped in the target rock formation. Horizontal drilling and pumping water for hydraulic fracturing release additional engine emissions compared to conventional production techniques. In addition, when the produced water “flows back” out of the well, raw gas from the producing formation can be released into the atmosphere at the wellhead.[15]

In both associated and non-associated gas production, water and hydrocarbon liquids are separated from the gas stream after it is produced at the wellhead. The gas separation process may involve some fuel combustion and can also involve some venting and/or flaring. Shale plays in particular are geologically heterogeneous, and the energy requirements to extract gas can vary widely. Moreover, the methane content of raw gas varies widely among different gas formations. Although some gas is pure enough to be used as-is, most gas is first transported by pipeline from the wellhead to a gas processing plant. Gas processing plants remove additional hydrocarbon liquids such as ethane and butane as well as gaseous impurities from the raw gas, including CO_2, in order for the gas to be pipeline-quality and ready to be compressed and transported. This “formation” CO_2 is vented at the gas processing plant and represents another source of GHG emissions along with the combustion emissions from the plant’s processing equipment.

From the gas processing plant, natural gas is transported, generally over long distances by interstate pipeline to the “city gate” hub and then to the power plant. The vast majority of the compressors that pressurize the pipeline to move

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[14] *EIA Annual Energy Outlook 2011. DOE/EIA-0383ER(2011). Energy Information Administration, U.S. Department of Energy. http://www.eia.gov/forecasts/aeo/pdf/0383(2011).pdf*

[15] *The GHG comparison between conventional and shale wells is important given the rapidly evolving industrial landscape with a share shift toward shale wells. For its part, the International Energy Agency (IEA) in a June 2011 Special Report: “Are We Entering a Global Age of Gas?” concluded that the LCA emissions of natural gas from shale wells is between 3.5 and 12 percent more than from conventional gas. IEA, June 2011, page 64.*

the gas are fueled by natural gas, although a small share is powered by electricity.[16] Compressors emit CO_2 emissions during fuel combustion and are also a source of fugitive and vented methane emissions through leaks in compressor seals, valves, and connections and through venting that occurs during operations and maintenance. Compressor stations constitute the primary source of vented methane emissions in natural gas transmission. Actual leakage from the pipelines themselves is very small.

Some power plants receive gas directly from transmission pipelines, while others have gas delivered through smaller distribution pipelines operated by local gas distribution companies (LDCs). Distribution lines do not typically require gas compression; however, some relatively small methane emissions do occur due to leakage from older distribution lines and valves, connections, and metering equipment.

Review of Recent Bottom-Up Life-Cycle Analyses: The Marginal Impact on Emissions

The assessment of how much more methane is released from shale gas production than from conventional production is a key factor in the discussion of possible changes in the life-cycle emissions of natural gas. As the shale gas component of U.S. production increases, a higher marginal greenhouse gas footprint from shale gas would raise the average greenhouse gas footprint of the U.S. natural gas supply overall. On the other hand, changing production technology and regulation could reduce emissions from both shale and other natural gas wells. The life-cycle GHG comparison between shale and conventional natural gas therefore has important implications for stakeholders who are considering policies and investment on the basis of how carbon-intensive natural gas is today and how carbon-intensive it is likely to be in the future.

A number of recent bottom-up life-cycle analyses attempt to quantify the GHG comparison between conventional and shale gas. Exhibit 2 shows the results of several of these analyses and how they compare to our top down analysis, which follows later.[17] Bottom-up figures are taken from studies by Skone, et al. (NETL), Jiang et al. (Jiang), and Howarth, et al. (Howarth). Because these and other life-cycle studies each make different assumptions as to the global warming potential of methane and the product whose greenhouse gas footprint is being measured—some use units of natural gas produced, others use units of natural gas delivered, and still other use units of electricity generated—we have normalized these figures using a GWP of 25. Any remaining variability in the GHG estimates are the result of differences in underlying emissions factors used. Despite differences in methodology and coverage, all of the recent studies except Howarth et al. estimate that life-cycle emissions from natural gas-fired generation are significantly less than those from coal-fired generation on a per MMBtu basis. As can be seen in Exhibit 2, our GHG estimate for average U.S. gas based on EPA's 2011 data (72.3 kg/MMBtu) is very similar to the National Energy Technology Laboratory's (NETL) bottom-up estimate for Barnett Shale gas (73.5 kg/MMBtu).

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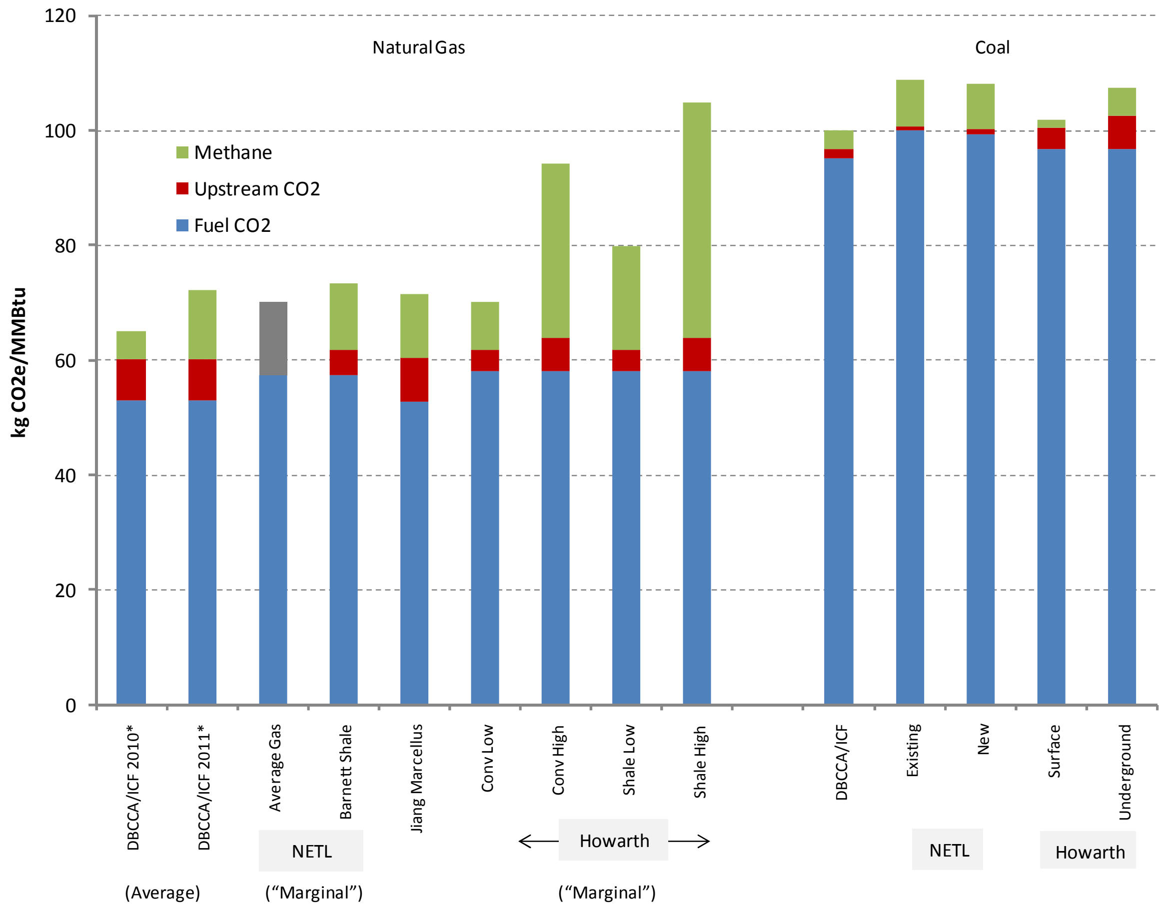
[16] ORNL, Transportation Energy Data Book, Oak Ridge National Laboratory, U.S. Department of Energy, June 2010, http://cta.ornl.gov/data/index.shtml

[17] The results of the top-down life-cycle analysis conducted in the present study are displayed for reference. Bottom-up figures are taken from studies by Skone, et al. 2011 (NETL), Jiang et al. 2011 (Jiang), and Howarth, et al. 2011 (Howarth). All studies are normalized using a 100-year GWP for methane of 25, and given in kg CO_2e per MMBtu of fuel rather than kg CO_2e per MWh of electricity generated. Most studies use MMBtu of fuel produced as their metric; the present study uses MMBtu of fuel consumed, an explanation of which is given on p. 22. .

Exhibit 2. Comparison of Recent Bottom-Up Life-Cycle Assessments.



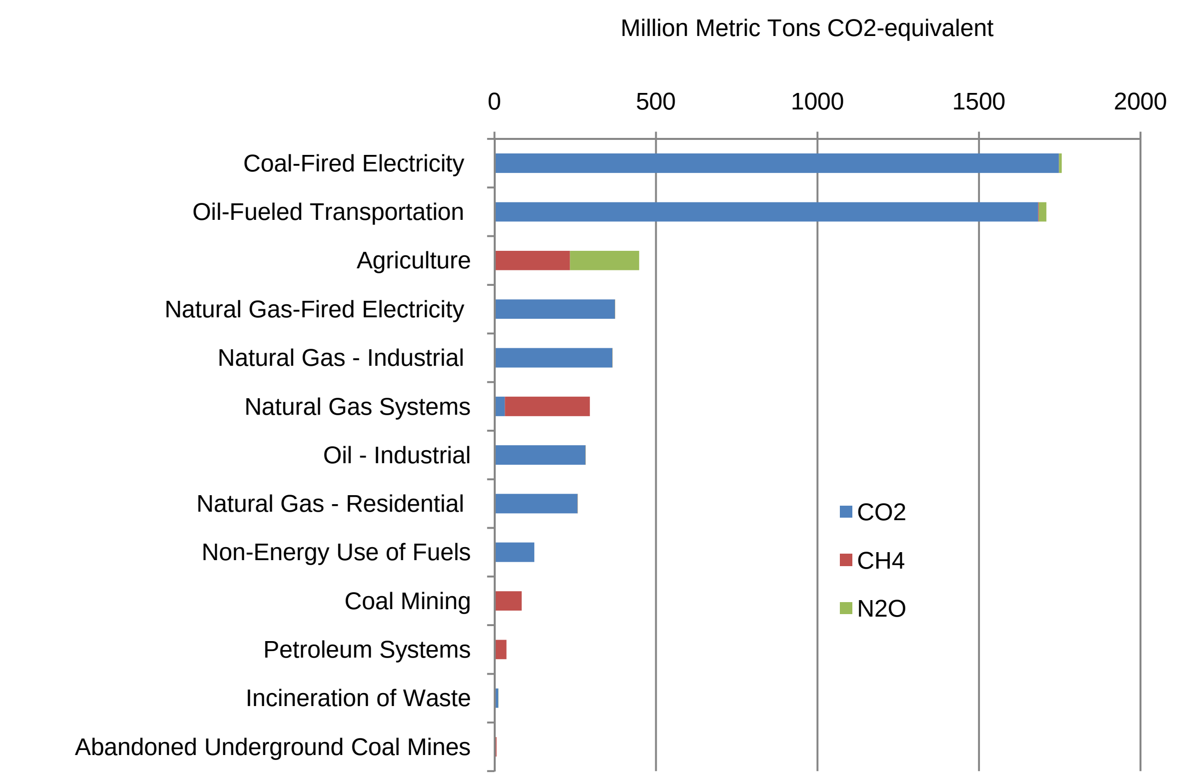
Source: DBCCA Analysis, 2011. Note: NETL Average Gas study includes bar shaded grey due to inability to segregate upstream CO2 and methane values, which were both accounted for in the study. *2011 EPA methodology compared to 2010.

Many of these studies draw upon data from the U.S. Environmental Protection Agency's *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (hereafter "Inventory" or "Greenhouse Gas Inventory). The Inventory, published annually, is the official U.S. report on GHG emissions to the UN IPCC and the source for much of the analysis of U.S. emissions.[18] The inventory is developed from a variety of public and private data sources on the many different kinds of GHG emission sources in different sectors. It uses a combination of "bottom-up" analysis, utilizing counts and characteristics of individual facilities, and "top-down" analysis, such as national data on fuel combustion from the Energy Information Administration (EIA) to calculate CO_2 emissions from combustion, to build an estimate for total U.S. GHG annual emissions across a range of sectors.

Greenhouse gas emissions from natural gas and coal production, processing, transport, and distribution are estimated in the Inventory's "Natural Gas Systems" and "Coal Mining." In the EPA's 2011 edition of the Inventory, Natural Gas Systems were estimated to be the largest source of non-combustion, energy-related GHG emissions in the U.S., at 296 million metric tons of CO_2 equivalent (MMT CO_2e) in 2009. Coal mining came in third, with an estimated 85 MMT CO_2e of emissions. Fossil fuel combustion accounted for the vast majority of GHG emissions from the U.S. energy sector, with an estimated 1,747.6 MMT CO_2e coming from coal-fired electricity generation alone, while natural gas-fired electricity generation accounted for an additional 373.1 MMT CO_2e (Exhibit 3).[19]

[18] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009* (April 2011), available at http://epa.gov/climatechange/emissions/usinventoryreport.html.
[19] All figures given in CO_2-equivalent here and elsewhere assume a global warming potential of 25 for methane unless otherwise noted. The EPA's Inventory uses a GWP of 21 for reporting purposes, so these numbers were converted to make them consistent with the GWP used for

Exhibit 3. U.S. Greenhouse Gas Emissions by Source Category, 2009.



These are the highest-emitting energy and agriculture sector source categories for 2009. Source: EPA 2011. Data were adjusted to use most recent IPCC GWPs for CH4 and N2O (25 and 298, respectively).

We draw two main conclusions from our survey of recent bottom-up life-cycle assessments. First, **the natural gas industry's practices are evolving rapidly, and better data are essential to ensuring that life-cycle greenhouse gas assessments remain up-to-date and reflect current industry behavior**. All of the bottom-up life-cycle assessments we surveyed identified significant uncertainty around certain segments of the natural gas life cycle stemming from data inadequacy. Among the sources of uncertainty identified were: formation-specific production rates, flaring rates during extraction and processing, construction emissions, transport distance, penetration and effectiveness of green completions and workovers, and formation-specific gas compositions.

Second, because shale gas appears to have a GHG footprint some 8 to 11 percent higher than conventional gas on a life-cycle basis per mmBtu based on these bottom up studies that we reviewed, **increased production of shale gas would tend to increase the average life-cycle GHG footprint from U.S. natural gas production if methane emissions from the upstream portion of the natural gas life are unmitigated**. This fact underlines **the importance of implementing the many existing control technologies and practices that can significantly reduce the overall greenhouse gas footprint of the natural gas industry**. Many companies are already reducing vented and flared methane emissions voluntarily through the EPA's voluntary Natural Gas STAR program. For example, the Inventory estimates that the completion emissions of methane from two thirds of shale gas production are already being mitigated through flaring or reduced emission completion.[20] If this is correct, then bottom-up life-cycle GHG estimates that do not account for reduced emissions completions are likely too high.

the main analysis in this paper. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009* (April 2011), available at http://epa.gov/climatechange/emissions/usinventoryreport.html.

[20] *Ibid.*

Stronger regulations limiting methane and other air pollutant emissions from oil and natural gas operations are also likely to lead to lower overall GHG emissions. Some states already require the adoption of certain methane controls: Wyoming and Colorado, for example, already require “no-flare” or “green” completions and workovers, which are reported to capture 70 to 90 percent of methane vented during completions and workovers following hydraulic fracturing. Because this methane can then be sold, users of green completions have reported payback times of less than one year.[21] Moreover, the EPA released proposed regulations for the gas production sector on July 28, 2011 that are expected to require mitigation of completion emissions from all wells.[22] This regulation is currently in the comment period and is set to be implemented by court order in 1Q12. If these regulations are adopted, there will be little or no difference between the emissions of hydraulically fractured and conventional gas wells.

Top-Down Life-Cycle Analysis of U.S. Natural Gas and Coal: Impact on the Average

The remainder of this paper develops a top-down life-cycle greenhouse gas analysis of natural gas and coal for the purpose of determining the impact of recent EPA revisions to methane emissions estimation methodologies on the current comparison between U.S. natural gas and coal-fired electricity.

Natural Gas

This analysis for natural gas includes each of the industry steps described in Exhibit 1 above. (See Appendix A for a detailed methodology.) The source of information for methane emissions and non-combustion CO_2 is the EPA’s *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009* (April 2011 release), which includes updated estimates for methane emissions from natural gas production that are approximately twice the level indicated in the previous 2010 edition.[23] This LCA uses the data from both 2010 and 2011 EPA inventory reports to illustrate the effect that the EPA’s latest increase in estimated methane emissions has on the overall LCA for gas (as discussed below), which we estimate to be about an 11 percent increase in the life-cycle emissions.

The U.S. Energy Information Administration (EIA) is the primary source for the data on natural gas consumption and associated CO_2 emissions in the various segments of the gas industry (fuel for gas compressors and gas processing plants).[24] In addition to the natural gas, petroleum is used for drill rigs, trucks and other mobile equipment, such as pumps for hydraulic fracturing. This analysis uses information from the Economic Census to estimate non-natural gas energy consumption and associated CO_2 emissions in the production sector.[25]

Sources of methane emissions are many and vary widely. Apart from EIA there are very few sources of aggregated data in the public domain. As noted earlier, the EPA recently increased its estimates significantly for several processes in natural gas production, and better data availability on methane leakage and venting will be critical going forward given the rapidly evolving gas production landscape. On this score, disclosures and reporting of upstream emissions have historically been voluntary. And while there is evidence that large volumes of GHGs are being captured by industry, the actual penetration rates of these voluntary programs is unknown[26].

For example, the EPA Natural Gas STAR program, a voluntary methane mitigation program, reports that its members reduced methane emissions from natural gas systems by 904 billion cubic feet between 2003 and 2009—equivalent to 365 $MMTCO_2e$.[27] This program has identified and documented many methane mitigation measures that could be applied more widely across both industries and are included in the EPA’s Inventory of US Greenhouse Gas Emissions

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[21] EPA, Natural Gas STAR Program, “Reduced Emissions Completions: Lessons Learned,” available at http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf, viewed 2 August 2011.
[22] *EPA, “Oil and Natural Gas Air Pollution Standards,” http://epa.gov/airquality/oilandgas/, viewed 18 August 2011.*
[23] *The new EPA data have raised questions on two ends, with some believing the estimates are too high and others believing they are too low. Some comments submitted to the EPA from gas producers about the Draft Inventory question the validity of these revisions, believing them too high. While on the other hand, there are environmental advocacy groups that question whether EPA’s “activity factors” used in its methodology accurately represent the preponderance of shale wells being drilled in the Gulf Coast and North East regions, thereby raising the question of whether the emission factors are indeed high enough.*
[24] *EIA, Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*
[25] *U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census*
[26] *Reported 2009 Natural Gas STAR voluntary emission reductions were the equivalent of ~$344 million in revenue (assuming $4/mmBtu gas) and the avoidance of 34.8 mn tonnes CO_2e; http://www.epa.gov/gasstar/accomplishments/index.html#content*
[27] *EPA Natural Gas STAR Program Accomplishments, page 2; http://www.epa.gov/gasstar/accomplishments/index.html*

and Sinks report.[28] Additionally, many mitigation activities are not reported to these programs. It is also possible that the EPA is missing or has underestimated some sources of upstream emissions for both natural gas and coal. Nevertheless, we expect that better information will be available in the spring of 2012 when reporting of data on upstream methane emissions through EPA's GHG Reporting Program commences.

In our LCA, the emission factors for the combustion of natural gas, coal and petroleum includes the CO_2 from complete combustion of the fuel plus the small amounts of nitrous oxide (N_2O) and unburned methane that result from the combustion. The emission factors for fuel combustion are taken from subpart C of the EPA Greenhouse Gas Reporting Program.[29] The N_2O and methane emissions from combustion are less than 1% of the CO_2 emissions. The total emission factors for combustion are:

- Natural gas – 53.07 kg CO_2 e/MMBtu
- Diesel fuel – 74.21 kg CO_2 e/MMBtu
- Coal – 95.11 kg CO_2 e/MMBtu

Exhibit 4 summarizes the data on total upstream GHG emissions calculated for the natural gas sector for the year 2008 using the April 2011 EPA inventory for methane adjusted for a methane GWP of 25 and the EIA data on fuel consumption. According to this inventory, U.S. production, processing, and transport of natural gas emitted 387.0 million tons of CO_2 equivalent ($MMTCO_2e$) in 2008.

Exhibit 4. Baseline U.S. Upstream Gas Emission Data for 2008 ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	146.3	11.3	47.2	204.8
Processing	18.7	21.4	19.4	59.5
Transmission	51.5	0.1	35.4	87.1
Distribution	35.6			35.6
Total	252.1	32.8	102.1	387.0

In this analysis, we adjust several factors to more accurately and robustly capture the life-cycle emissions associated with the use of natural gas on a national basis.

First, the emissions estimates account for natural gas production in the United States; however, because 13 percent of natural gas consumed in the U.S. was imported in 2008, we increase the production and processing emissions estimates to account for emissions from gas imports. Of that 13 percent in 2008, 11.7 percent was imported by pipeline from North America, mostly from Canada. The analysis assumes that other North American production operations are similar to those in the United States, so the emissions are increased linearly to account for these imports. In addition, 1.3 percent of the gas supply arrived via liquefied natural gas (LNG) imports. The LNG life cycle includes additional emissions associated with liquefaction, transportation, and regasification from source to use. The LNG portion is escalated by 76 percent to account for these emissions, based on a bottom-up LNG LCA prepared by NETL.[30] These are the most significant modifications made in our analysis, increasing the overall LCA for natural gas by 39 $MMTCO_2e$, or about 10 percent, primarily due to the adjustment for pipeline imports.

A second adjustment relates to methane emissions from distribution lines at local gas distribution companies. Since only 52 percent of the gas used for power generation is delivered by local distribution lines, the methane emissions associated with distribution have been discounted by that amount.[31] This reduces the total emissions by 18 $MMtCO_2e$, or 4 percent.

[28] *EPA,* Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009*, April 2011, available at http://www.epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Complete_Report.pdf, p. 152.*
[29] *EPA, Greenhouse Gas Reporting Program, Subpart C, U.S. Environmental Protection Agency, http://www.epa.gov/climatechange/emissions/ghgrulemaking.html*
[30] *Skone, T.J., 2010. Life Cycle Greenhouse Gas Analysis of Power Generation Options, National Energy Technology Laboratory, U.S. Department of Energy*
[31] *EIA, EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition", Energy Information Administration, U.S. Department of Energy. http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP1&CFID=5251631&CFTOKEN=51c7f7f0104e329d-3FD56B17-237D-DA68-24412047FB2CE3CB*

A final adjustment is for methane emissions from production of associated gas—gas produced from oil wells. We did this in order to accurately adjust the impact of associated gas in our net import correction. Most oil wells produce some natural gas, and some of this gas is collected and becomes part of the gas supply. The EPA inventory of U.S. GHG emissions estimates that methane emissions from petroleum systems are approximately 30 $MMTCO_2e$ per year.[32] Since some domestic natural gas is co-produced with petroleum, these emissions could be considered for inclusion in the LCA of emissions from the natural gas sector.

The associated natural gas produced and the methane emitted during petroleum production, processing, and transport are a byproduct of petroleum production. Methane emissions would occur even if no natural gas were captured and delivered for end-use consumption. In fact, the emissions might actually be higher in that case since there would be no economic incentive to capture the gas. By this assessment it would not be appropriate to count the methane emissions from petroleum production, since they are independent of the production of gas.

On the other hand, associated gas produced from oil wells represents a significant segment of U.S. gross withdrawals of natural gas, and if there are methane emissions associated with that production, it seems appropriate to include them in the LCA, even if the production is incidental to oil production. In that case, we have to evaluate how much of the methane emissions to allocate to gas production versus petroleum production. This calculation is shown in Appendix A and results in an additional 5 $MMTCO_2e$ of emissions being added, or a 1.4 percent increase.

Exhibit 5 shows our adjusted total emissions for 2008, which come to 423.8 $MMTCO_2e$ compared to the 387.0 baseline. The production segment is the largest contributor to GHG emissions from the natural gas supply chain, accounting for 57 percent of total emissions. Of the different gases, methane accounts for 59 percent of total GHG emissions using a GWP of 25.

Exhibit 5. Adjusted Total Upstream GHG Emissions from Natural Gas, 2008 ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	173.7	12.9	62.2	248.7
Processing	21.3	24.4	22.2	67.9
Transmission	51.5	0.1	37.2	88.8
Distribution	18.3	0.0	0.0	18.3
Total	264.9	37.4	121.5	423.8

To compare emissions from coal and natural gas on an apples-to-apples basis, the emissions are normalized to the amount of GHG per million Btu (MMBtu) of *natural gas delivered to consumers* using EIA data for gas deliveries[33]. Some LCAs normalize to GHG per unit of natural gas *produced*, which includes associated gas that is reinjected into the producing formation as well as natural gas liquids that are removed during gas processing and gas lost through fugitives and venting, in addition to gas actually delivered to consumers such as power plants. Using delivered rather than produced natural gas results in a slightly higher overall figure for life-cycle emissions but depicts more accurately the energy that is actually available to power plants. The total normalized upstream emissions are 19.2 kg CO_2e/MMBtu of natural gas delivered. (See Exhibit 6.) As discussed earlier, the emissions for combustion of the natural gas at the power plant are 53.1 kg CO_2e/MMBtu, so the total life-cycle GHG emissions at the point of use are 72.3 kg/MMBtu. Of this, the upstream emissions are 30 percent, 60 percent of which are from methane.

[32] *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2009, EPA 340-R-11-005, April 2011 page, 27*
[33] *EIA, Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*

Exhibit 6. Normalized Life-Cycle GHG Emissions for Natural Gas for 2008, using EPA 2011 Methane Emissions Methodolgy (kg CO_2e/MMBtu)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	7.9	0.6	2.8	11.3
Processing	1.0	1.1	1.0	3.1
Transmission	2.3	0.0	1.7	4.0
Distribution	0.8	0.0	0.0	0.8
Total Upstream	12.0	1.7	5.5	19.2
Fuel Combustion	0	0	53.1	53.1
Total	12.0	1.7	58.6	72.3

Doing the same calculation with the lower methane emissions estimated in the prior year's EPA inventory yields a value of 12.0 kg CO_2e/MMBtu for the upstream emissions. (See Exhibit 7) Including the end-use gas consumption, total life-cycle emissions are 65.1 kg CO_2/MMBtu, with the upstream portion accounting for 20 percent. In this case, methane makes up only about 40 percent of the upstream gas GHG footprint.

Exhibit 7. Normalized Life-Cycle GHG Emissions for Natural Gas for 2008, using EPA 2010 Methane Emissions Methodology (kg CO_2e/MMBtu)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	1.2	0.4	2.8	4.4
Processing	0.8	1.1	1.0	2.9
Transmission	2.1	0.0	1.7	3.8
Distribution	0.8	0.0	0.0	0.8
Upstream Total	4.9	1.6	5.5	12.0
Fuel Combustion	0	0	53.1	53.1
Total	4.9	1.6	58.6	65.1

Finally, Exhibit 8 applies the most recent EPA data to calculate the life-cycle emissions for 2009 using the 2011 methane emissions methodology. This is the most recent year for which data are available. The 2009 emissions are quite similar to the emissions calculated for 2008 using the same methodology (73.1 vs 72.1 expressed as kg CO2e/MMBtu).

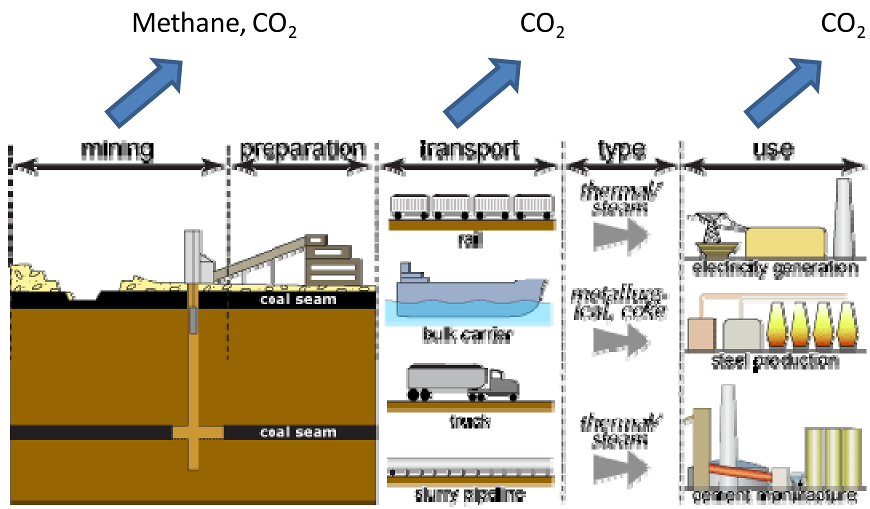
Exhibit 8. Normalized Life-Cycle GHG Emissions for Natural Gas for 2009, using EPA 2011 Methane Emissions Methodology (kg CO_2e/MMBtu)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	8.4	0.6	3.0	12.0
Processing	1.1	1.1	1.0	3.2
Transmission	2.4	0.0	1.6	4.0
Distribution	0.8	0.0	0.0	0.8
Upstream Total	12.8	1.7	5.6	20.1
Fuel Combustion	0.0	0.0	53.1	53.1
Total	12.8	1.7	58.7	73.1

Coal

The production and distribution of coal is simpler to analyze than that of natural gas because there are fewer steps in production and processing (Exhibit 9). Coal is produced in the U.S. from underground mines (40 percent) and surface mines (60 percent). In underground mines, most of the mining equipment is driven by electricity. In surface mines, the equipment runs on diesel fuel or electricity. This analysis estimates the direct and indirect emissions of the mining processes from Economic Census data[34]. (For detailed calculations of the coal LCA, see Appendix A.)

Exhibit 9. Coal Industry Segments and Emission Sources



Source: University of Wyoming

Coal formations contain methane, which is released when the coal is mined. The methane content varies among different coal formations but is generally higher for underground mines than for surface mines. Underground mines use ventilation to remove the methane, which is a safety hazard, and in some cases the methane can be recovered for use or flared to reduce GHG emissions. The U.S. GHG Inventory estimates the methane emissions from coal mining. Coal mines that are no longer active (i.e., are “abandoned”) release methane as well: 7.0 MMTCO$_2$e in 2008 (at 25 GWP). This would add an additional 0.4 kg CO$_2$e/MMBtu to the coal LCA but is not included here since we do not have similar data on methane emissions from abandoned gas wells.

Data on coal transportation by mode are available from the Economic Census[35]. More than 90 percent of coal is transported by train, with the remainder transported by barge, truck, or various combinations of these modes. This analysis derives the energy consumption per ton-mile from several sources to calculate CO_2 emissions. (See Appendix A.)

The United States is a net exporter of coal by 4 percent, so the production data are adjusted downward by that amount. Table 6 shows the adjusted upstream GHG emissions for coal, totaling 117.8 MMTCO$_2$e.

[34] *U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census*

[35] *Ibid.*

Exhibit 10. Adjusted Total Upstream GHG Emissions from Coal for 2008 ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	79.9	0.0	14.0	93.9
Transportation	0.0	0.0	23.9	23.9
Total	79.9	0.0	37.9	117.8

As with the natural gas LCA, this analysis "normalizes" total emissions by the energy delivered to coal consumers (more than 90% power of whom are power generators), or 1,147 million short tons of coal in 2008. This yields a normalized upstream emission factor of 4.8 kg CO_2e/MMBtu consumed. (See Exhibit 11.) This value is about 25 percent of the upstream emissions from natural gas. The emission factor for combustion of coal is 95.1 kg/MMBtu, bringing the total end-use life-cycle emissions to 99.9 kg CO_2/MMBtu. In this case, although methane comprises 63 percent of the upstream emissions, the upstream component is only 5 percent of the total, with CO_2 emissions from the combustion of the coal itself being the dominant factor in the total life-cycle emissions.

Exhibit 11. Normalized Life-Cycle GHG Emissions from Coal for 2008 (kg CO_2e/MMBtu)

	Methane	CO_2 and N_2O from Combustion	**Total**
Production	3.3	0.6	3.9
Transportation	0.0	1.0	1.0
Total Upstream	3.3	1.5	4.8
Coal Combustion	0.0	95.1	95.1
End Use Total	3.3	96.6	99.9

Electricity Generation

Finally, life-cycle GHG emissions per MMBtu of fuel delivered to power plants are normalized to GHG emissions per MWh of electricity generated to account for the difference in coal and natural gas power plant efficiencies. In 2008, essentially all coal-fired electricity in the United States was generated by steam-turbine power plants, which combust fuel to boil water and use the resulting steam to drive a turbine.[36] Many coal plants are run almost all the time at full capacity to provide baseload power. Technology has improved over the past several decades and new plants have improved combustion efficiencies, but many active plants in the U.S. fleet were built before 1970 and are less efficient.

By contrast, natural gas is used in a range of power plant technologies, each of which fills a different role in the electricity dispatch. In 2008, only 12 percent of natural gas-fired electricity was generated by steam-turbine plants, most of which were built before 1980 and are relatively inefficient. An additional 9 percent was generated by simple-cycle gas turbines, relatively inefficient plants that are used to provide peaking power during limited periods. Since 2000, a large portion of new natural gas capacity additions have been combined-cycle units, which use waste heat from gas turbines to run steam turbines.

Combined-cycle plants have superior heat rates and may be used to provide baseload or intermediate power, depending on the particular grid and the price of gas. In 2008, 79 percent of gas-fired electricity was generated by combined-cycle plants. Two coal plants in the U.S. currently gasify coal to generate electricity in a combined-cycle configuration, but such plants, called Integrated Gasification Combined Cycle (IGCC) plants, have very low market penetration today.

[36] *All 2008 generation data from Energy Information Administration (EIA), Form EIA-923, 2008.*

The heat rate (the amount of fuel in Btus needed to generate a kilowatt-hour of electricity) of the electric generator is one of the most significant variables in estimating the GHG emissions per MWh of electricity.[37] Unless otherwise specified, this analysis uses heat rates representing the average efficiency of existing power plants in the U.S. fleet:

- **Average efficiency of existing capital stock:** National average values are based on EIA data for total gas or coal consumption for generation and total generation by each fuel. The heat rates are 8,044 Btu/kWh (41 percent efficiency) for gas generation and 11,044Btu/kWh (31 percent efficiency) for coal generation.

A sensitivity analysis comparing life-cycle emissions results using average heat rates and heat rates representative of new natural gas and coal plants is shown in Appendix A (Exhibit A-12).

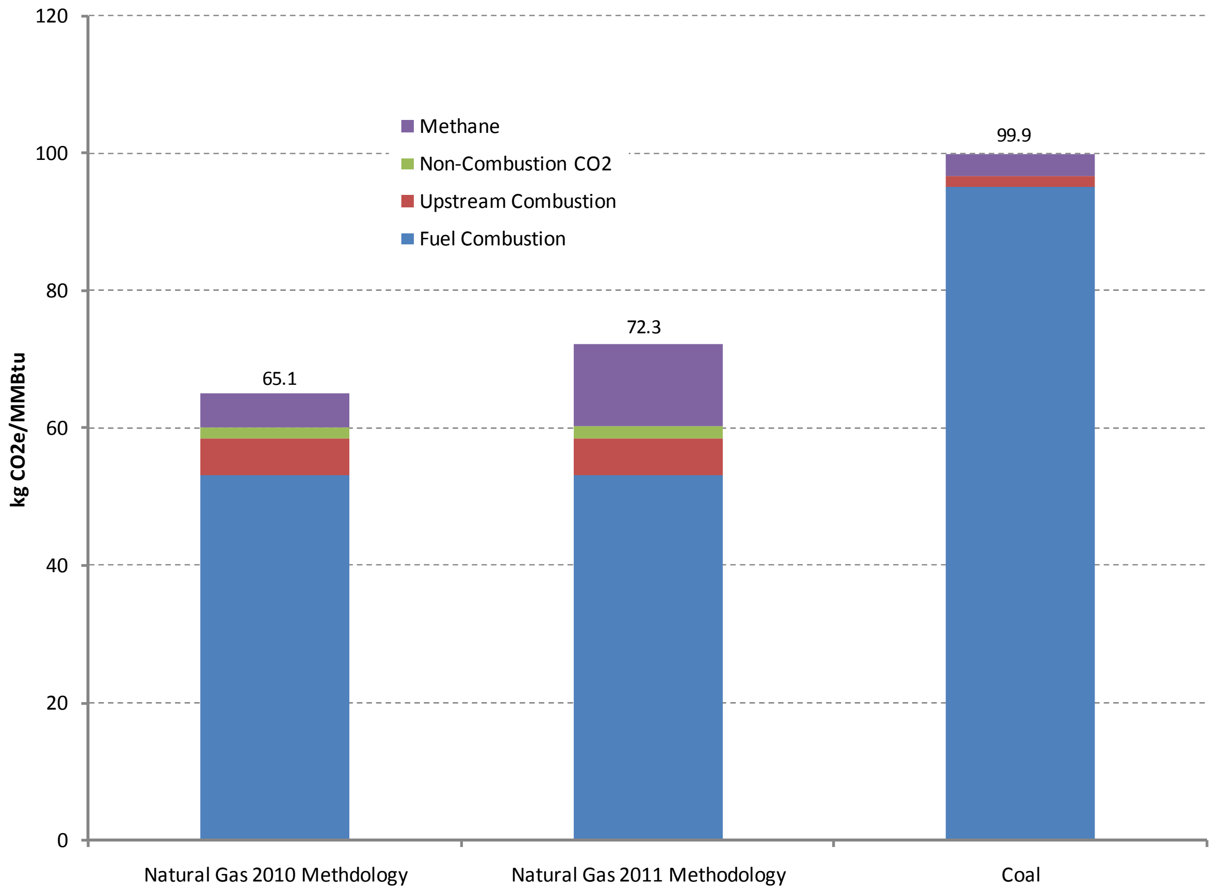
- **Efficiency of new plants:** In its *Annual Energy Outlook 2010*[38], EIA provides a value for a new plant in 2009, and for future plants that accounts for future cost reductions from learning and production efficiencies ("nth" plant). The values used here are the average of the two values for a gas combined-cycle plant (6,998 Btu/kWh, 49 percent efficiency) and a new supercritical coal plant (8,970 Btu/kWh, 38 percent efficiency).

Summary of Results and Sensitivity Analysis for Top=Down Analysis

Exhibit 12 compares the calculated LCA emissions (by GHG) for gas delivered to power plants for (a) natural gas using the EPA 2010 methodology, (b) natural gas using the EPA 2011 methodology, and (c) coal. In all cases, the emissions are dominated by CO_2 from final combustion of the fuel at the power plant. The upstream emissions are larger for gas, and the power plant combustion emissions are higher for coal. The LCA for coal is dominated by the CO_2 from the coal combustion itself. The upstream component is larger for natural gas, and methane is a larger component of the emissions. Using the increased methane emission estimate for gas from the 2011 methodology results in the LCA for natural gas being 11 percent higher than with the 2010 estimate. The gas life-cycle value using the 2011 methodology is 28 percent lower than the coal value.

[37] The power industry uses efficiency and heat rate to express power plant efficiency. Heat rate in Btu/kWh = 3413/efficiency. A lower heat rate signifies a higher efficiency.
[38] *EIA, Assumptions to the Annual Energy Outlook 2010 – Table 8-2,* DOE/EIA-0554(2010), *Energy Information Administration, U.S. Department of Energy.* *http://www.eia.gov/oiaf/aeo/assumption/pdf/electricity_tbls.pdf*

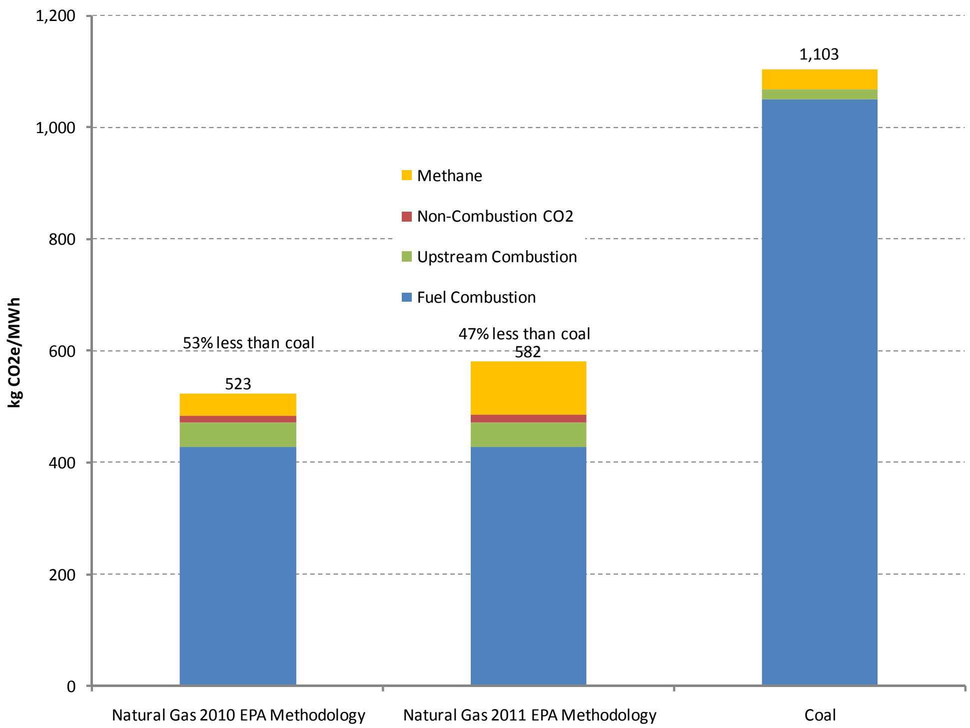
Exhibit 12: Life-Cycle Emissions as Delivered to Power Plants, 2008 (kg CO_2e/MMBtu)



Source: DBCCA Analysis 2011

Exhibit 13 shows the LCA in terms of GHG emissions per megawatt-hour of electricity generated from gas and coal, using the national average power plant efficiencies. The gas value using the 2011 EPA methane emissions estimates is 582 kg CO_2e/MWh—or 11 percent higher than the 523 kg CO_2e/MWh calculated using data for 2010 methodology. The value for coal is 1,103 kg CO_2e/MWh. Because coal plants are on average less efficient than gas plants, the difference between gas and coal is greater than the fuel-only comparison at the burner tip prior to combustion and conversion to electricity. **Natural gas-fired electricity, using the 2011 methodology, has 47 percent lower life-cycle GHG emissions per unit of electricity than coal-fired electricity.**

Exhibit 13: Electric Generating LCA, by Greenhouse Gas, 2008 (kg CO_2e/MWh)



Source: DBCCA Analysis 2011

Conclusions

Our top-down LCA of natural gas and coal-based generation using publicly available data shows that the EPA's recent revision of methane emissions increases the life-cycle GHG emissions for natural gas-fired electricity by about 11 percent from estimates based on the earlier values. Our conclusion is that, on average, natural gas-fired power generation emits significantly fewer GHGs compared to coal-fired power generation. Life-cycle emissions for natural gas generation using new EPA estimates are 47 lower than for coal-based generation when using a GWP of 25. The impact of different GWPs to our LCA can be found in Appendix B.

Nevertheless, methane, despite its shorter lifetime than carbon dioxide, is of concern as a GHG. Compared to coal-fired generation, methane emissions, including a large venting component, comprise a much larger share of natural-gas generation's GHGs. And while measurement of upstream emissions and public disclosure of those emissions still has room for improvement, methane emissions during the production, processing, transport, storage, and distribution of natural gas can be mitigated now at moderately low cost using existing technologies and best practices. Such capture potential presents a commercial and investment opportunity that would further improve the life-cycle GHG footprint of natural gas.

Appendix A
Detailed Methodology and Calculations

Natural Gas

The natural gas LCA addresses emissions from extraction through electricity generation for 2008. The primary data sources are the EPA *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2009* and EIA data on natural gas consumption[39]. Exhibit A-1 shows the basic information on total emissions by industry segment for 2008. The methane emissions are from the EPA Inventory and adjusted from a GWP of 21 to a GWP of 25. The non-combustion CO_2 emissions are from the same source and include CO_2 from combustion of flared gas and the formation CO_2 vented from gas processing plants. The CO_2 from combustion is primarily from the EIA data on gas consumption in the gas industry. The gas consumed in the production segment is the "lease gas" reported by EIA, which is gas consumed in the producing areas. EIA also reports "vented and flared gas," which is assumed here to be all flared but is already included in the EPA category of non-combustion emissions. The "processing" category includes the "plant gas" reported by EIA, and "transmission" includes the pipeline and distribution fuel reported by EIA. The total upstream emissions from these sources are 387.0 $MMTCO_2e$ based on a 100 year GWP of 25.

Detailed data collection and verification, as well as LCA harmonization to common metrics and system boundaries are critical for improving the rigor of LCA analysis. The National Renewable Energy Laboratory's Joint Institute for Strategic Energy Analysis, www.jisea.org, will be conducting such an evaluation in the coming months, which may improve upon the historical data sets used by EPA.

Exhibit A-1: Basic U.S. Upstream Gas Emission Data for 2008 ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	146.3	11.3	47.2	204.8
Processing	18.7	21.4	19.4	59.5
Transmission	51.5	0.1	35.4	87.1
Distribution	35.6			35.6
Total	252.1	32.8	102.1	387.0

There are several additions to this basic information. First, there are some electric driven compressors on the pipeline network. This electricity consumption of 2,936.6 million kWh is from the ORNL *Transportation Data Book*[40]. (That estimate is based on a fixed share of 1.5 percent of the natural gas consumption.) The emission factor for electricity throughout the analysis is 603 kg CO_2/MWh, calculated from EIA data on total generation and CO_2 emissions. This electricity consumption adds 1.8 $MMTCO_2e$ to the pipeline emissions. There is also diesel fuel, gasoline and other petroleum fuel used in gas drilling and production that is not separately reported by EIA. This information is collected by the Economic Census[41]**Error! Bookmark not defined.** but only by NAICS code and only every 10 years (the latest reporting year is 2007). The four relevant NAICS codes are: 211111 (crude petroleum and natural gas extraction); 211112 (natural gas liquid extraction); 213111 (drilling oil and gas wells); and 213112 (support activities for oil and gas operations).

Three of these codes (excepting NGL extraction) combine data for oil and gas operation. The gas portion is calculated based on the gas share of U.S. producing oil and gas wells (55.4 percent) or active drilling rigs (83.2 percent). Also, the Census lists expenditures only by fuel type. The actual consumption is estimated from the expenditures based on average price for each fuel. The consumption is then converted to CO_2 emissions using the emission factors from the EPA GHG Reporting Program. These emissions are then escalated from 2007 to 2008 based on EIA data for production (3.9 percent increase). The calculations are summarized in Exhibit A-2. Total emissions for this segment are 7.2 $MMTCO_2e$.

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[39] *EIA, Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*
[40] *ORNL, Transportation Energy Data Book, Oak Ridge National Laboratory, U.S. Department of Energy, June 2010, http://cta.ornl.gov/data/index.shtml*
[41] *U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census*

Exhibit A-2: Gas Industry Upstream Non-Gas Emissions

Energy Consumption (MMBtu)						
NAICS		Distillate	Gasoline	Other	Residual Oil	Undistributed
211111	Extraction	29,055,998	10,031,608	--	6,539,144	8,502,932
211112	NGL Extraction	288,585	352,861	66,627	--	168,613
213111	Drilling	10,014,334	3,808,638	551,713	3,967,479	5,446,747
213112	Support	20,671,552	13,157,404	893,604	7,166,105	4,389,137

CO_2 Emission Factors		Distillate	Gasoline	Other	Residual Oil	Other
		73.96	70.22	62.98	75.1	62.98

CO_2 Emissions ($MMTCO_2e$)						
211111	Extraction	2.1	0.7	0	0.5	0.5
211112	NGL Extraction	0	0	0	0	0
213111	Drilling	0.7	0.3	0	0.3	0.3
213112	Support	1.5	0.9	0.1	0.5	0.3

Gas Share of Emissions ($MMTCO_2e$)						
21111	Extraction	1.8	0.6	0	0.4	0.4
211112	NGL Extraction	0	0	0	0	0
213111	Drilling	0.4	0.1	0	0.2	0.2
213112	Support	1.3	0.8	0	0.4	0.2

Source: EPA, ORNL, Census Bureau, DBCCA Analysis 2011

Another adjustment is for methane emissions from “associated” gas produced from oil wells. Most oil wells produce gas, much of which is captured and delivered to consumers. The EPA *Inventory of U.S. GHG Emissions* estimates methane emissions from petroleum systems to be approximately 30 $MMTCO_2e$ per year.

Since some domestic natural gas is co-produced with petroleum, one could consider all of these emissions be included in the life-cycle analysis of emissions from the natural gas sector. However, the natural gas produced and the methane emissions are a byproduct of petroleum production. Methane emissions would occur even if no natural gas were captured and delivered for end-use consumption. In fact, the emissions might actually be higher in that case since there would be no economic incentive to capture the gas. One could also therefore maintain that it is not appropriate to count the methane emissions from petroleum production toward gas use, since they are independent of the production of gas and are related to petroleum consumption.

On the other hand, associated gas produced from oil wells is a significant segment of U.S. gross withdrawals of natural gas, and if there are methane emissions associated with that production, it seems appropriate to include them in the life-cycle analysis, even if the production is incidental to oil production. In that case, we have to evaluate how much of the methane emissions to allocate to gas production versus petroleum production.

The EPA inventory separates the methane emissions from petroleum systems at the wellhead oil separator. Methane emitted on the oil side downstream from the separator is allocated to the petroleum side, and methane emitted on the natural gas side is allocated to the natural gas side. The part that must be allocated here is the upstream production emissions, of which the largest components are miscellaneous venting and fugitives and venting from gas-powered pneumatic devices. The approach in this analysis is to simply allocate these emissions based on the energy value of oil versus gas produced from these wells.

According to the EIA, the gross production of natural gas from petroleum wells in 2008 was 5.7 trillion cubic feet (Tcf)[42]. However, much of this gas (3.3 Tcf) was not gathered for sale but was reinjected into the producing formation. Some of the gas is reinjected to push more oil out of the formation. Most of the reinjection (3.0 Tcf) is from Alaska production where there is no pipeline to bring the gas to market. It is reinjected as a means of storage until the time when a pipeline may be built to the lower 48 states. In any case, the associated gas actually produced for potential sale is 2.5 Tcf. On an energy basis, this is 20 percent energy value of the net associated gas plus the 1.8 billion barrels of U.S. oil production in 2008.

Of the methane emission sources in petroleum production, we include pneumatic device venting, combustion and process upsets, miscellaneous venting and fugitives, and wellhead fugitives. Tank venting is not included because it is purely related to oil production. Total methane emissions for these sources in 2008 were 25.6 MMTCO$_2$e, according to the EPA inventory. Taking 20 percent of this total gives 5.0 MMTCO$_2$e of additional methane emissions to allocate to the natural gas LCA, increasing the unadjusted emission baseline by 1.4 percent.

With these additions (electricity, non-gas fuel, and methane from petroleum systems), total upstream gas production emissions are 402.0 MMTCO$_2$e.

The total emissions are then adjusted for imports. The calculations above include emissions for U.S. production, but a net 13 percent of natural gas was imported in 2008. Of this, 11.7 percent was imported by pipeline from Mexico and Canada (mostly the latter). This analysis assumes that production processes are similar throughout North America, so the production emissions are escalated by 11.7 percent to account for the pipeline imports. The remaining 1.3 percent of imports were LNG imports. LNG has a higher LCA than conventional gas due to gasification, liquefaction, and transportation processes. The LCA for LNG is estimated at 176 percent of conventional gas based on the LCA performed by NETL[30] The production emissions for the LNG component are increased by this amount. The adjustment for imports is the largest adjustment, increasing the emissions by about 39 MMTCO$_2$e, or 10 percent.

The other adjustment in this analysis is related to fugitive methane emissions from gas distribution lines at local gas distribution companies (LDCs). Methane emissions from local distribution lines are 35.6 MMTCO$_2$e (at 25 GWP), but many power plants receive gas deliveries directly from interstate pipelines rather than via local distribution lines. Relatively few power plants actually purchase gas from LDCs, but some receive gas deliveries from the LDCs. The EIA-176 survey[43] provides data on deliveries by LDCs to electric generators; however, these reported deliveries total 6.5 Tcf, which is almost equal to total gas consumption for electricity generation. This is because intrastate pipeline deliveries in California, Texas, and Florida are included in the EIA-176 survey. Excluding these three states, 59 percent of gas to electric generators is delivered by LDCs. Based on this, only 59 percent of the distribution company methane emissions are included in the adjusted values. This adjustment decreases the emissions by about 17 MMTCO$_2$e, or 4 percent. Exhibit A-3 shows the adjusted final upstream GHG emissions for natural gas: 423.8 MMTCO$_2$e. Methane emissions account for more than half of the total.

Exhibit A-3: Adjusted Total Upstream GHG Emissions from Natural Gas for 2008, using EPA 2011 Methodology for Methane (MMTCO$_2$e)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	173.7	12.9	62.2	248.7
Processing	21.3	24.4	22.2	67.9
Transmission	51.5	0.1	37.2	88.8
Distribution	18.3	0.0	0.0	18.3
Total	264.9	37.4	121.5	423.8

These total emissions are then normalized to kg CO$_2$e/MMBtu of delivered natural gas based on the EIA data on natural gas delivered to consumers: 21.4 trillion cubic feet (Tcf). The total normalized upstream emissions are 19.2 kg CO$_2$e/MMBtu. (See Exhibit A-4.) The emissions for combustion of the gas at the point of use are 53.07 kg

[42] *EIA, Natural gas navigator. Natural gas gross withdrawals and production. http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm*
[43] *EIA, EIA-176, "Annual Report of Natural and Supplemental Gas Supply and Disposition", Energy Information Administration, U.S. Department of Energy. http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP1&CFID=5251631&CFTOKEN=51c7f7f0104e329d-3FD56B17-237D-DA68-24412047FB2CE3CB*

CO_2e/MMBtu (including N_2O and unburned methane), so the total life-cycle GHG emissions at the point of use are 70.4 kg CO_2e/MMBtu. Of this, the upstream emissions are 24 percent and methane is slightly over half of the upstream component.

Exhibit A-4: Normalized Life-cycle GHG Emissions for Natural Gas for 2008, using 2011 EPA Methodology for Methane (kg CO_2/MMBtu)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	7.9	0.6	2.8	11.3
Processing	1.0	1.1	1.0	3.1
Transmission	2.3	0.0	1.7	4.0
Distribution	0.8	0.0	0.0	0.8
Total Upstream	12.0	1.7	5.5	19.2
Fuel Combustion	0	0	53.1	53.1
Total	12.0	1.7	58.6	72.3

The same methodology is applied using EPA's 2010 estimate of methane emissions, to show the effect of the updated, increased 2011 methane emission estimate. Exhibits A-5 and A-6 show the total and normalized emissions for this case. The normalized upstream emissions with the old data are 12.0 kg CO_2e/MMBtu. Including the end-use gas combustion; total life-cycle emissions including end-use combustion are 65.1 kg CO_2/MMBtu, with the upstream portion accounting for 20 percent. In this case, methane makes up only about 40 percent of the upstream gas GHG footprint.

Exhibit A-5: Adjusted Total Upstream GHG Emissions from Natural Gas, 2008, using 2010 EPA Methodology for Methane (MMTCO_2e)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	25.9	9.7	62.2	97.8
Processing	17.7	24.4	22.2	64.2
Transmission	46.9	0.1	37.2	84.2
Distribution	18.3	0.0	0.0	18.3
Total	108.8	34.2	121.5	264.6

Exhibit A-6: Normalized Life-cycle GHG Emissions for Natural Gas for 2008, using 2010 EPA Methodology for Methane (kg CO_2/MMBtu)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	1.2	0.4	2.8	4.4
Processing	0.8	1.1	1.0	2.9
Transmission	2.1	0.0	1.7	3.8
Distribution	0.8	0.0	0.0	0.8
Upstream Total	4.9	1.6	5.5	12.0
Fuel Combustion	0	0	53.1	53.1
Total	4.9	1.6	58.6	65.1

Coal LCA

The upstream energy consumption for coal production is calculated using the 2007 Economic Census[44] data on fuel and electricity consumption in the same way as the non-gas fuel for gas production. In this case, there is a separate NAICS code for coal production, so no adjustments are necessary. The same CO_2 emission factors and the emission factor for electricity use are used as for the data on gas production. (See Exhibit A-7.) The values are adjusted from 2007 to 2008 based on the production in each year—a 2.2 percent increase. The total CO_2 emissions from energy consumption for coal production are 14.0 $MMTCO_2e$. Methane emissions from coal mines of 67.1 $MMTCO_2e$ (79.9 at 25 GWP) are taken from the EPA GHG inventory. Methane from abandoned coal mines is not included.

Exhibit A-7: Upstream GHG Calculation for Coal

	Coal	Distillate	Natural Gas	Gasoline	Residual Oil	Other	Electricity (MWh)
MMBtu	3,607,020	52,597,178	2,487,920	4,846,529	25,739,212	2,039,820	11,444,477
kg CO2/MMBtu	94.38	73.96	53.02	70.22	75.10	62.98	603.01
MMTCO2e	0.34	3.89	0.13	0.34	1.93	0.13	6.90

The estimate of transportation emissions is based on the Commodity Flow Summary[45] developed by the U.S. Department of Transportation and Census Bureau, which provides information on ton-miles of coal transported by different modes. Rail is the primary mode of transportation, with rail-only accounting for 91 percent of the ton-miles and rail and other modes (truck and barge) accounting for the remainder. This analysis applies a ton-mile fuel consumption factor[46, 47, 48] to calculate fuel consumption and converts the fuel consumption to CO_2 using the same EPA emission factors used for other sectors. (See Exhibit A-8.) For mixed mode, rail or barge are assumed to account for 75 percent of the ton-miles and truck for 50 percent. Most coal is delivered via dedicated equipment—e.g., a coal unit train travels only to and from the mine to the power plant. Thus, the fuel consumed in returning empty to the mine must be included. This analysis assumes 100-percent empty return as part of the energy consumption, with the empty fuel consumption being one-third of the loaded consumption based on the weight of the empty vehicle. The total consumption calculated is 23.9 $MMTCO_2$.

Exhibit A-8: GHG Calculation for Coal Transportation

Mode	Ton-Miles (million)	Fuel Consumption (ton-mi/gal)	GHG Emissions (MMTCO2)	Round-Trip Emissions (MMTCO2)
Truck	14,002	110.00	1.28	1.67
Rail	773,290	480.00	16.26	21.13
Water	6,548	730.00	0.09	0.12
Truck and rail	785	388.00	0.02	0.03
Truck and water	7,257	575.00	0.13	0.17
Rail and water	26,994	605.00	0.45	0.59
Other multiple modes	4,353	480.00	0.09	0.12
Other and unknown modes	2,567	480.00	0.05	0.07
Total	835,796	-	18.38	23.89

In the case of coal, the U.S. is a net exporter of about 4 percent of its production, so the total production emissions are adjusted downward by this amount to calculate the emissions attributable to coal consumed in the U.S. Exhibit A-9 shows the final adjusted upstream emissions: 117.8 $MMTCO_2e$.

[44] *U.S. Department of Commerce, Census of Mining 2007, Census Bureau, U.S. Department of Census*
[45] *U.S. Department of Transportation, Research and Innovative Technology Administration, Bureau of Transportation Statistics and U.S. Census Bureau, 2007 Commodity Flow Survey.*
[46] *Federal Railroad Administration, "Comparative Evaluation of Rail and Truck Fuel Efficiency on Competitive Corridors", November 19, 2009.*
[47] *Army Corps of Engineers, "Waterborne Commerce Statistics Center", http://www.ndc.iwr.usace.army.mil//data/data1.htm*
[48] *American Railroad Association*

Exhibit A-9: Adjusted Total Upstream GHG Emissions from Coal, 2008 ($MMTCO_2e$)

	Methane	Non-Combustion CO_2	CO_2 and N_2O from Combustion	**Total**
Production	79.9	0.0	14.0	93.9
Transportation	0.0	0.0	23.9	23.9
Total	79.9	0.0	37.9	117.8

These values are then normalized by the total 2008 consumption of coal in the U.S. of 1,147 million tons of coal, assuming an average heating value of 10,250 Btu/lb.[49] This yields a normalized upstream emission factor of 4.3 kg CO_2/MMBtu consumed. (See Exhibit A-10.) The value is about 25 percent of the upstream emissions from natural gas. The emission factor for combustion of coal is 95.1 kg CO_2e/MMBtu, bringing the total end use life-cycle emissions to 99.9 kg CO_2/MMBtu. In this case, although methane is still 63 percent of the upstream emissions, the upstream component is only 4 percent of the total, with the CO_2 emissions from the coal itself being the dominant factor.

Exhibit A-10: Normalized Upstream GHG Emissions for Coal for 2008 (kg CO_2/MMBtu)

	Methane	CO_2 and N_2O from Combustion	**Total**
Production	3.3	0.6	3.9
Transportation	0.0	1.0	1.0
Total Upstream	3.3	1.5	4.8
Coal Combustion	0.0	95.1	95.1
End Use Total	3.3	96.6	99.9

Electricity Generation
The efficiency[50] of the electric generator is one of the most significant variables in estimating the GHG emissions per MWh of electricity. This analysis looks at two values:

- **National average efficiency values** based on EIA data[51, 52, 53, 54] for total gas or coal consumption for generation and total generation by each fuel. (See Exhibit A-11.)

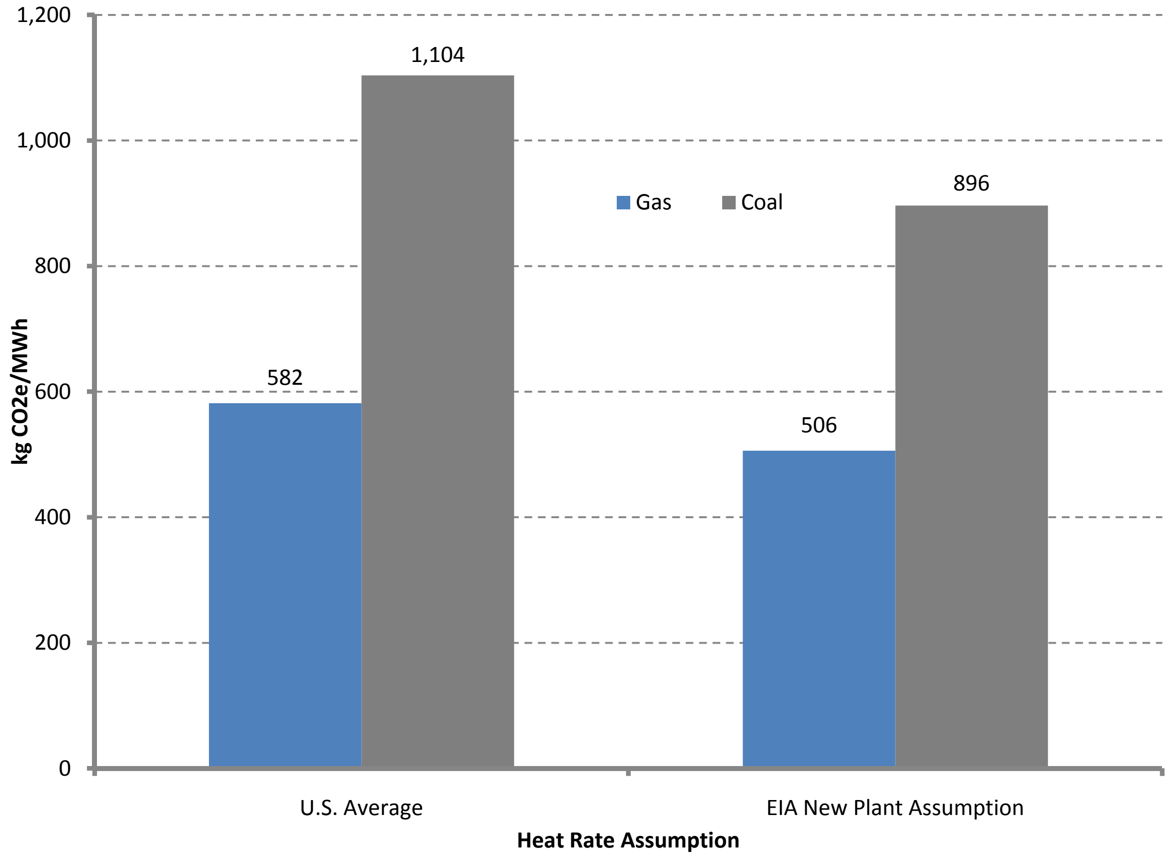
- **Efficiency[55] for new power plants** assumed by the EIA in its *Annual Energy Outlook 2010*[38]. EIA provides a value for a new plant in 2009 and for subsequent plants ("nth plant") of each type for which the cost may be lower due to learning and production improvement. The values used here are the average of the values for a gas combined-cycle plant (6,998 Btu/kWh, 49 percent efficiency) and a new supercritical coal plant (8,970 Btu/kWh, 38 percent efficiency). (See Exhibit A-12.)

Exhibit A-11: Calculation of Average Power Plant Efficiencies

	Energy Consumption (Quads)	Generation (Billion kWh)	Heat Rate (Btu / kWh)	Efficiency
Gas	7	883.00	8,044.00	0.42
Coal	22	1,986.00	11,044.00	0.31

[49] *EIA, Annual Coal Data, Energy Information Administration, U.S. Department of Energy, http://www.eia.gov/totalenergy/data/annual/pdf/sec7_5.pdf*
[50] *The power industry uses efficiency and heat rate to express power plant efficiency. Heat rate is Btu/kWh = 3413/efficiency. A lower heat rate signifies a higher efficiency.*
[51] *EIA, Electric Power Monthly, Energy Information Administration, U.S. Department of Energy, http://www.eia.doe.gov/cneaf/electricity/epm/table2_4_a.html*
[52] *EIA, Electric Power Monthly, Energy Information Administration, U.S. Department of Energy, http://www.eia.doe.gov/aer/txt/ptb0802a.html*
[53] *EIA, Annual Energy Review, Energy Information Administration, U.S. Department of Energy, http://www.eia.doe.gov/cneaf/electricity/epm/table2_1_a.html*
[54] *EIA, Quarterly Coal Report, U.S. Department of Energy, http://www.eia.gov/cneaf/coal/quarterly/html/t32p01p1.pdf*

Exhibit A-12: Effect of Power Plant Heat Rate on Life-Cycle Emissions



Source: DBCCA analysis, 2011.

Appendix B
Effect of Global Warming Potential (GWP)

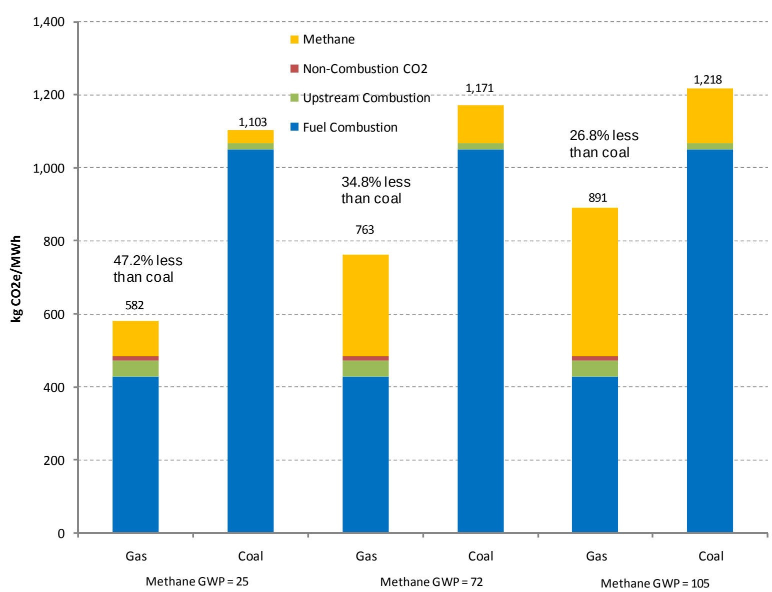
Methane is a potent GHG and its effect varies depending on the lifetime over which it is evaluated. The IPCC uses a 100 year lifetime for its analysis and a 100 year GWP of 25 for methane. Others believe that short-lived GHGs should be evaluated on a 20 year lifetime.

In its recently completed study on natural gas, MIT explains the reasons that a 100 GWP is commonly used:

> *"Because the various GHGs have different lives in the atmosphere (e.g., on the scale of a decade for methane, but centuries for CO_2), the calculation of GWPs depends on the integration period. Early studies calculated this index for 20-, 100- and 500-year integration periods. The IPCC decided to use the 100-year measure, and it is a procedure followed by the U.S. and other countries over several decades. An outlier in this domain is the Cornell study which recommends the application of the 20-year value in inter-fuel comparison. A 20-year GWP would emphasize the near-term impact of methane but ignore serious longer-term risks of climate change from GHGs that will remain in the atmosphere for hundreds to thousands of years, and the 500-year value would miss important effects over the current century. Methane is a more powerful GHG than CO_2, and its combination of potency and short life yields the 100-year GWP used in this study."*[56]

In addition, scientific work continues on the appropriate GWPs for different GHGs. Although the IPCC 20-year GWP for methane is 72, new work by Shindell et al[57] proposes a 20-year GWP of 105 for methane. Exhibit B-1 above shows the effect of different methane GWPs on the LCA using the EPA 2011 methodology. Since methane is a much larger component of the LCA for natural gas, the GWP has a much larger effect on gas than coal. Going from the 100 year GWP to the 20-year GWP of 72 increases life-cycle emissions for natural gas by 31 percent and for coal by only 6 percent. At the GWP of 72, the power plant emissions for natural gas are 35 percent lower than those for coal. At the 105 GWP, the emissions for the gas-fired plant are 27 percent lower than those for coal.

Exhibit B-1: Effect of Methane GWP on Life-Cycle Emissions



Source: DBCCA Analysis 2011

[56] *The Future of Natural Gas, Moniz, Ernest J.; Jacoby, Henry D.; Meggs, Anthony J.M. (Study co-chairs), MIT Energy Initiative, 2011.*
[57] *Shindell DT, Faluvegi G, Koch DM, Schmidt GA, Unger N, Bauer SE (2009) Improved attribution of climate forcing to emissions. Science 326:716–718*

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LETTER

Methane and the greenhouse-gas footprint of natural gas from shale formations

A letter

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Abstract We evaluate the greenhouse gas footprint of natural gas obtained by high-volume hydraulic fracturing from shale formations, focusing on methane emissions. Natural gas is composed largely of methane, and 3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the life-time of a well. These methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas. The higher emissions from shale gas occur at the time wells are hydraulically fractured—as methane escapes from flow-back return fluids—and during drill out following the fracturing. Methane is a powerful greenhouse gas, with a global warming potential that is far greater than that of carbon dioxide, particularly over the time horizon of the first few decades following emission. Methane contributes substantially to the greenhouse gas footprint of shale gas on shorter time scales, dominating it on a 20-year time horizon. The footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years.

Keywords Methane · Greenhouse gases · Global warming · Natural gas · Shale gas · Unconventional gas · Fugitive emissions · Lifecycle analysis · LCA · Bridge fuel · Transitional fuel · Global warming potential · GWP

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Many view natural gas as a transitional fuel, allowing continued dependence on fossil fuels yet reducing greenhouse gas (GHG) emissions compared to oil or coal over coming decades (Pacala and Socolow 2004). Development of "unconventional" gas dispersed in shale is part of this vision, as the potential resource may be large, and in many regions conventional reserves are becoming depleted (Wood et al. 2011). Domestic production in the U.S. was predominantly from conventional reservoirs through the 1990s, but by 2009 U.S. unconventional production exceeded that of conventional gas. The Department of Energy predicts that by 2035 total domestic production will grow by 20%, with unconventional gas providing 75% of the total (EIA 2010a). The greatest growth is predicted for shale gas, increasing from 16% of total production in 2009 to an expected 45% in 2035.

Although natural gas is promoted as a bridge fuel over the coming few decades, in part because of its presumed benefit for global warming compared to other fossil fuels, very little is known about the GHG footprint of unconventional gas. Here, we define the GHG footprint as the total GHG emissions from developing and using the gas, expressed as equivalents of carbon dioxide, per unit of energy obtained during combustion. The GHG footprint of shale gas has received little study or scrutiny, although many have voiced concern. The National Research Council (2009) noted emissions from shale-gas extraction may be greater than from conventional gas. The Council of Scientific Society Presidents (2010) wrote to President Obama, warning that some potential energy bridges such as shale gas have received insufficient analysis and may aggravate rather than mitigate global warming. And in late 2010, the U.S. Environmental Protection Agency issued a report concluding that fugitive emissions of methane from unconventional gas may be far greater than for conventional gas (EPA 2010).

Fugitive emissions of methane are of particular concern. Methane is the major component of natural gas and a powerful greenhouse gas. As such, small leakages are important. Recent modeling indicates methane has an even greater global warming potential than previously believed, when the indirect effects of methane on atmospheric aerosols are considered (Shindell et al. 2009). The global methane budget is poorly constrained, with multiple sources and sinks all having large uncertainties. The radiocarbon content of atmospheric methane suggests fossil fuels may be a far larger source of atmospheric methane than generally thought (Lassey et al. 2007).

The GHG footprint of shale gas consists of the direct emissions of CO_2 from end-use consumption, indirect emissions of CO_2 from fossil fuels used to extract, develop, and transport the gas, and methane fugitive emissions and venting. Despite the high level of industrial activity involved in developing shale gas, the indirect emissions of CO_2 are relatively small compared to those from the direct combustion of the fuel: 1 to 1.5 g C MJ^{-1} (Santoro et al. 2011) vs 15 g C MJ^{-1} for direct emissions (Hayhoe et al. 2002). Indirect emissions from shale gas are estimated to be only 0.04 to 0.45 g C MJ^{-1} greater than those for conventional gas (Wood et al. 2011). Thus, for both conventional and shale gas, the GHG footprint is dominated by the direct CO_2 emissions and fugitive methane emissions. Here we present estimates for methane emissions as contributors to the GHG footprint of shale gas compared to conventional gas.

Our analysis uses the most recently available data, relying particularly on a technical background document on GHG emissions from the oil and gas industry (EPA 2010) and materials discussed in that report, and a report on natural gas losses on federal lands from the General Accountability Office (GAO 2010). The

EPA (2010) report is the first update on emission factors by the agency since 1996 (Harrison et al. 1996). The earlier report served as the basis for the national GHG inventory for the past decade. However, that study was not based on random sampling or a comprehensive assessment of actual industry practices, but rather only analyzed facilities of companies that voluntarily participated (Kirchgessner et al. 1997). The new EPA (2010) report notes that the 1996 "study was conducted at a time when methane emissions were not a significant concern in the discussion about GHG emissions" and that emission factors from the 1996 report "are outdated and potentially understated for some emissions sources." Indeed, emission factors presented in EPA (2010) are much higher, by orders of magnitude for some sources.

1 Fugitive methane emissions during well completion

Shale gas is extracted by high-volume hydraulic fracturing. Large volumes of water are forced under pressure into the shale to fracture and re-fracture the rock to boost gas flow. A significant amount of this water returns to the surface as flow-back within the first few days to weeks after injection and is accompanied by large quantities of methane (EPA 2010). The amount of methane is far more than could be dissolved in the flow-back fluids, reflecting a mixture of fracture-return fluids and methane gas. We have compiled data from 2 shale gas formations and 3 tight-sand gas formations in the U.S. Between 0.6% and 3.2% of the life-time production of gas from wells is emitted as methane during the flow-back period (Table 1). We include tight-sand formations since flow-back emissions and the patterns of gas production over time are similar to those for shale (EPA 2010). Note that the rate of methane emitted during flow-back (column B in Table 1) correlates well to the initial production rate for the well following completion (column C in Table 1). Although the data are limited, the variation across the basins seems reasonable: the highest methane emissions during flow-back were in the Haynesville, where initial pressures and initial production were very high, and the lowest emissions were in the Uinta, where the flow-back period was the shortest and initial production following well completion was low. However, we note that the data used in Table 1 are not well documented, with many values based on PowerPoint slides from EPA-sponsored workshops. For this paper, we therefore choose to represent gas losses from flow-back fluids as the mean value from Table 1: 1.6%.

More methane is emitted during "drill-out," the stage in developing unconventional gas in which the plugs set to separate fracturing stages are drilled out to release gas for production. EPA (2007) estimates drill-out emissions at 142×10^3 to 425×10^3 m^3 per well. Using the mean drill-out emissions estimate of 280×10^3 m^3 (EPA 2007) and the mean life-time gas production for the 5 formations in Table 1 (85×10^6 m^3), we estimate that 0.33% of the total life-time production of wells is emitted as methane during the drill-out stage. If we instead use the average life-time production for a larger set of data on 12 formations (Wood et al. 2011), 45×10^6 m^3, we estimate a percentage emission of 0.62%. More effort is needed to determine drill-out emissions on individual formation. Meanwhile, in this paper we use the conservative estimate of 0.33% for drill-out emissions.

Combining losses associated with flow-back fluids (1.6%) and drill out (0.33%), we estimate that 1.9% of the total production of gas from an unconventional shale-gas

Table 1 Methane emissions during the flow-back period following hydraulic fracturing, initial gas production rates following well completion, life-time gas production of wells, and the methane emitted during flow-back expressed as a percentage of the life-time production for five unconventional wells in the United States

	(A) Methane emitted during flow-back (10^3 m^3)[a]	(B) Methane emitted per day during flow-back (10^3 m^3 day^{-1})[b]	(C) Initial gas production at well completion (10^3 m^3 day^{-1})[c]	(D) Life-time production of well (10^6 m^3)[d]	(E) Methane emitted during flow-back as % of life-time production[e]
Haynesville (Louisiana, shale)	6,800	680	640	210	3.2
Barnett (Texas, shale)	370	41	37	35	1.1
Piceance (Colorado, tight sand)	710	79	57	55	1.3
Uinta (Utah, tight sand)	255	51	42	40	0.6
Den-Jules (Colorado, tight sand)	140	12	11	?	?

Flow-back is the return of hydraulic fracturing fluids to the surface immediately after fracturing and before well completion. For these wells, the flow-back period ranged from 5 to 12 days

[a]Haynesville: average from Eckhardt et al. (2009); Piceance: EPA (2007); Barnett: EPA (2004); Uinta: Samuels (2010); Denver-Julesburg: Bracken (2008)

[b]Calculated by dividing the total methane emitted during flow-back (column A) by the duration of flow-back. Flow-back durations were 9 days for Barnett (EPA 2004), 8 days for Piceance (EPA 2007), 5 days for Uinta (Samuels 2010), and 12 days for Denver-Julesburg (Bracken 2008); median value of 10 days for flow-back was assumed for Haynesville

[c]Haynesville: http://shale.typepad.com/haynesvilleshale/2009/07/chesapeake-energy-haynesville-shale-decline-curve.html1/7/2011 and http://oilshalegas.com/haynesvilleshalestocks.html; Barnett: http://oilshalegas.com/barnettshale.html; Piceance: Kruuskraa (2004) and Henke (2010); Uinta: http://www.epmag.com/archives/newsComments/6242.htm; Denver-Julesburg: http://www.businesswire.com/news/home/20100924005169/en/Synergy-Resources-Corporation-Reports-Initial-Production-Rates

[d]Based on averages for these basins. Haynesville: http://shale.typepad.com/haynesvilleshale/decline-curve/); Barnett: http://www.aapg.org/explorer/2002/07jul/barnett_shale.cfm and Wood et al. (2011); Piceance: Kruuskraa (2004); Uinta: http://www.epmag.com/archives/newsComments/6242.htm

[e]Calculated by dividing column (A) by column (D)

Table 2 Fugitive methane emissions associated with development of natural gas from conventional wells and from shale formations (expressed as the percentage of methane produced over the lifecycle of a well)

	Conventional gas	Shale gas
Emissions during well completion	0.01%	1.9%
Routine venting and equipment leaks at well site	0.3 to 1.9%	0.3 to 1.9%
Emissions during liquid unloading	0 to 0.26%	0 to 0.26%
Emissions during gas processing	0 to 0.19%	0 to 0.19%
Emissions during transport, storage, and distribution	1.4 to 3.6%	1.4 to 3.6%
Total emissions	1.7 to 6.0%	3.6 to 7.9%

See text for derivation of estimates and supporting information

well is emitted as methane during well completion (Table 2). Again, this estimate is uncertain but conservative.

Emissions are far lower for conventional natural gas wells during completion, since conventional wells have no flow-back and no drill out. An average of 1.04×10^3 m^3 of methane is released per well completed for conventional gas (EPA 2010), corresponding to 1.32×10^3 m^3 natural gas (assuming 78.8% methane content of the gas). In 2007, 19,819 conventional wells were completed in the US (EPA 2010), so we estimate a total national emission of 26×10^6 m^3 natural gas. The total national production of onshore conventional gas in 2007 was 384×10^9 m^3 (EIA 2010b). Therefore, we estimate the average fugitive emissions at well completion for conventional gas as 0.01% of the life-time production of a well (Table 2), three orders of magnitude less than for shale gas.

2 Routine venting and equipment leaks

After completion, some fugitive emissions continue at the well site over its lifetime. A typical well has 55 to 150 connections to equipment such as heaters, meters, dehydrators, compressors, and vapor-recovery apparatus. Many of these potentially leak, and many pressure relief valves are designed to purposefully vent gas. Emissions from pneumatic pumps and dehydrators are a major part of the leakage (GAO 2010). Once a well is completed and connected to a pipeline, the same technologies are used for both conventional and shale gas; we assume that these post-completion fugitive emissions are the same for shale and conventional gas. GAO (2010) concluded that 0.3% to 1.9% of the life-time production of a well is lost due to routine venting and equipment leaks (Table 2). Previous studies have estimated routine well-site fugitive emissions as approximately 0.5% or less (Hayhoe et al. 2002; Armendariz 2009) and 0.95% (Shires et al. 2009). Note that none of these estimates include accidents or emergency vents. Data on emissions during emergencies are not available and have never, as far as we can determine, been used in any estimate of emissions from natural gas production. Thus, our estimate of 0.3% to 1.9% leakage is conservative. As we discuss below, the 0.3% reflects use of best available technology.

Additional venting occurs during "liquid unloading." Conventional wells frequently require multiple liquid-unloading events as they mature to mitigate water intrusion as reservoir pressure drops. Though not as common, some unconventional wells may also require unloading. Empirical data from 4 gas basins indicate that 0.02

to 0.26% of total life-time production of a well is vented as methane during liquid unloading (GAO 2010). Since not all wells require unloading, we set the range at 0 to 0.26% (Table 2).

3 Processing losses

Some natural gas, whether conventional or from shale, is of sufficient quality to be "pipeline ready" without further processing. Other gas contains sufficient amounts of heavy hydrocarbons and impurities such as sulfur gases to require removal through processing before the gas is piped. Note that the quality of gas can vary even within a formation. For example, gas from the Marcellus shale in northeastern Pennsylvania needs little or no processing, while gas from southwestern Pennsylvania must be processed (NYDEC 2009). Some methane is emitted during this processing. The default EPA facility-level fugitive emission factor for gas processing indicates a loss of 0.19% of production (Shires et al. 2009). We therefore give a range of 0% (i.e. no processing, for wells that produce "pipeline ready" gas) to 0.19% of gas produced as our estimate of processing losses (Table 2). Actual measurements of processing plant emissions in Canada showed fourfold greater leakage than standard emission factors of the sort used by Shires et al. (2009) would indicate (Chambers 2004), so again, our estimates are very conservative.

4 Transport, storage, and distribution losses

Further fugitive emissions occur during transport, storage, and distribution of natural gas. Direct measurements of leakage from transmission are limited, but two studies give similar leakage rates in both the U.S. (as part of the 1996 EPA emission factor study; mean value of 0.53%; Harrison et al. 1996; Kirchgessner et al. 1997) and in Russia (0.7% mean estimate, with a range of 0.4% to 1.6%; Lelieveld et al. 2005). Direct estimates of distribution losses are even more limited, but the 1996 EPA study estimates losses at 0.35% of production (Harrison et al. 1996; Kirchgessner et al. 1997). Lelieveld et al. (2005) used the 1996 emission factors for natural gas storage and distribution together with their transmission estimates to suggest an overall average loss rate of 1.4% (range of 1.0% to 2.5%). We use this 1.4% leakage as the likely lower limit (Table 2). As noted above, the EPA 1996 emission estimates are based on limited data, and Revkin and Krauss (2009) reported "government scientists and industry officials caution that the real figure is almost certainly higher." Furthermore, the IPCC (2007) cautions that these "bottom-up" approaches for methane inventories often underestimate fluxes.

Another way to estimate pipeline leakage is to examine "lost and unaccounted for gas," e.g. the difference between the measured volume of gas at the wellhead and that actually purchased and used by consumers. At the global scale, this method has estimated pipeline leakage at 2.5% to 10% (Crutzen 1987; Cicerone and Oremland 1988; Hayhoe et al. 2002), although the higher value reflects poorly maintained pipelines in Russia during the Soviet collapse, and leakages in Russia are now far less (Lelieveld et al. 2005; Reshetnikov et al. 2000). Kirchgessner et al. (1997) argue against this approach, stating it is "subject to numerous errors including gas theft, variations in temperature and pressure, billing cycle differences, and meter inaccuracies." With the exception of theft, however, errors should be randomly distributed and should not bias the leakage estimate high or low. Few recent data on lost and unaccounted gas are publicly available, but statewide data for Texas averaged 2.3% in 2000 and 4.9% in 2007 (Percival 2010). In 2007, the State of Texas passed new legislation to regulate lost and unaccounted for gas; the legislation originally proposed a 5% hard cap which was dropped in the face of industry opposition (Liu 2008; Percival 2010). We take the mean of the 2000 and 2007 Texas data for missing and unaccounted gas (3.6%) as the upper limit of downstream losses (Table 2), assuming that the higher value for 2007 and lower value for 2000 may potentially reflect random variation in billing cycle differences. We believe this is a conservative upper limit, particularly given the industry resistance to a 5% hard cap.

Our conservative estimate of 1.4% to 3.6% leakage of gas during transmission, storage, and distribution is remarkably similar to the 2.5% "best estimate" used by Hayhoe et al. (2002). They considered the possible range as 0.2% and 10%.

5 Contribution of methane emissions to the GHG footprints of shale gas and conventional gas

Summing all estimated losses, we calculate that during the life cycle of an average shale-gas well, 3.6 to 7.9% of the total production of the well is emitted to the atmosphere as methane (Table 2). This is at least 30% more and perhaps more than twice as great as the life-cycle methane emissions we estimate for conventional gas, 1.7% to 6%. Methane is a far more potent GHG than is CO_2, but methane also has a tenfold shorter residence time in the atmosphere, so its effect on global warming attenuates more rapidly (IPCC 2007). Consequently, to compare the global warming potential of methane and CO_2 requires a specific time horizon. We follow Lelieveld et al. (2005) and present analyses for both 20-year and 100-year time horizons. Though the 100-year horizon is commonly used, we agree with Nisbet et al. (2000) that the 20-year horizon is critical, given the need to reduce global warming in coming decades (IPCC 2007). We use recently modeled values for the global warming potential of methane compared to CO_2: 105 and 33 on a mass-to-mass basis for 20 and 100 years, respectively, with an uncertainty of plus or minus 23% (Shindell et al. 2009). These are somewhat higher than those presented in the 4th assessment report of the IPCC (2007), but better account for the interaction of methane with aerosols. Note that carbon-trading markets use a lower global-warming potential yet of only 21 on the 100-year horizon, but this is based on the 2nd IPCC (1995) assessment, which is clearly out of date on this topic. See Electronic Supplemental Materials for the methodology for calculating the effect of methane on GHG in terms of CO_2 equivalents.

Methane dominates the GHG footprint for shale gas on the 20-year time horizon, contributing 1.4- to 3-times more than does direct CO_2 emission (Fig. 1a). At this time scale, the GHG footprint for shale gas is 22% to 43% greater than that for conventional gas. When viewed at a time 100 years after the emissions, methane emissions still contribute significantly to the GHG footprints, but the effect is diminished by the relatively short residence time of methane in the atmosphere. On this time frame, the GHG footprint for shale gas is 14% to 19% greater than that for conventional gas (Fig. 1b).

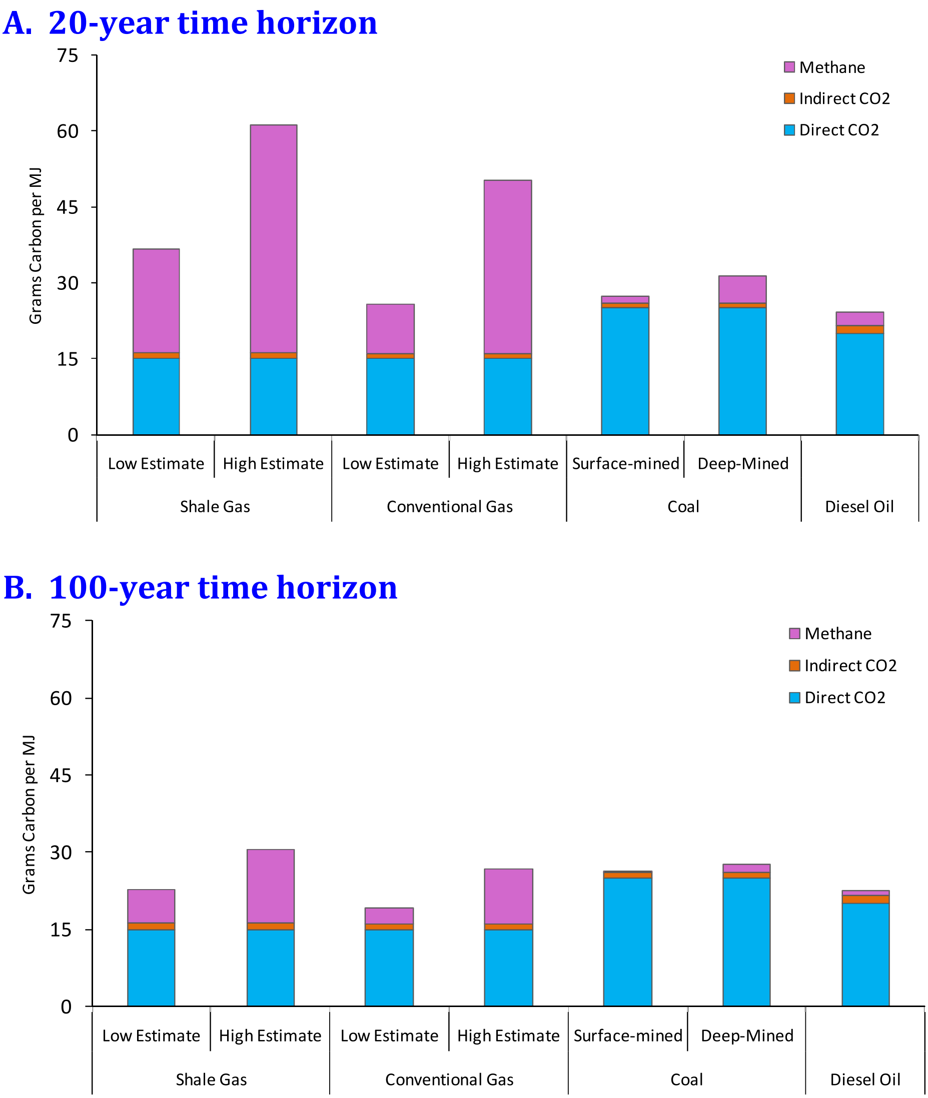

Fig. 1 Comparison of greenhouse gas emissions from shale gas with low and high estimates of fugitive methane emissions, conventional natural gas with low and high estimates of fugitive methane emissions, surface-mined coal, deep-mined coal, and diesel oil. **a** is for a 20-year time horizon, and **b** is for a 100-year time horizon. Estimates include direct emissions of CO_2 during combustion (*blue bars*), indirect emissions of CO_2 necessary to develop and use the energy source (*red bars*), and fugitive emissions of methane, converted to equivalent value of CO_2 as described in the text (*pink bars*). Emissions are normalized to the quantity of energy released at the time of combustion. The conversion of methane to CO_2 equivalents is based on global warming potentials from Shindell et al. (2009) that include both direct and indirect influences of methane on aerosols. Mean values from Shindell et al. (2009) are used here. Shindell et al. (2009) present an uncertainty in these mean values of plus or minus 23%, which is not included in this figure

6 Shale gas versus other fossil fuels

Considering the 20-year horizon, the GHG footprint for shale gas is at least 20% greater than and perhaps more than twice as great as that for coal when expressed per quantity of energy available during combustion (Fig. 1a; see Electronic Supplemental Materials for derivation of the estimates for diesel oil and coal). Over the 100-year frame, the GHG footprint is comparable to that for coal: the low-end shale-gas emissions are 18% lower than deep-mined coal, and the high-end shale-gas emissions are 15% greater than surface-mined coal emissions (Fig. 1b). For the 20 year horizon, the GHG footprint of shale gas is at least 50% greater than for oil, and perhaps 2.5-times greater. At the 100-year time scale, the footprint for shale gas is similar to or 35% greater than for oil.

We know of no other estimates for the GHG footprint of shale gas in the peer-reviewed literature. However, we can compare our estimates for conventional gas with three previous peer-reviewed studies on the GHG emissions of conventional natural gas and coal: Hayhoe et al. (2002), Lelieveld et al. (2005), and Jamarillo et al. (2007). All concluded that GHG emissions for conventional gas are less than for coal, when considering the contribution of methane over 100 years. In contrast, our analysis indicates that conventional gas has little or no advantage over coal even over the 100-year time period (Fig. 1b). Our estimates for conventional-gas methane emissions are in the range of those in Hayhoe et al. (2002) but are higher than those in Lelieveld et al. (2005) and Jamarillo et al. (2007) who used 1996 EPA emission factors now known to be too low (EPA 2010). To evaluate the effect of methane, all three of these studies also used global warming potentials now believed to be too low (Shindell et al. 2009). Still, Hayhoe et al. (2002) concluded that under many of the scenarios evaluated, a switch from coal to conventional natural gas could aggravate global warming on time scales of up to several decades. Even with the lower global warming potential value, Lelieveld et al. (2005) concluded that natural gas has a greater GHG footprint than oil if methane emissions exceeded 3.1% and worse than coal if the emissions exceeded 5.6% on the 20-year time scale. They used a methane global warming potential value for methane from IPCC (1995) that is only 57% of the new value from Shindell et al. (2009), suggesting that in fact methane emissions of only 2% to 3% make the GHG footprint of conventional gas worse than oil and coal. Our estimates for fugitive shale-gas emissions are 3.6 to 7.9%.

Our analysis does not consider the efficiency of final use. If fuels are used to generate electricity, natural gas gains some advantage over coal because of greater efficiencies of generation (see Electronic Supplemental Materials). However, this does not greatly affect our overall conclusion: the GHG footprint of shale gas approaches or exceeds coal even when used to generate electricity (Table in Electronic Supplemental Materials). Further, shale-gas is promoted for other uses, including as a heating and transportation fuel, where there is little evidence that efficiencies are superior to diesel oil.

7 Can methane emissions be reduced?

The EPA estimates that 'green' technologies can reduce gas-industry methane emissions by 40% (GAO 2010). For instance, liquid-unloading emissions can be greatly reduced with plunger lifts (EPA 2006; GAO 2010); industry reports a 99% venting reduction in the San Juan basin with the use of smart-automated plunger lifts (GAO 2010). Use of flash-tank separators or vapor recovery units can reduce dehydrator emissions by 90% (Fernandez et al. 2005). Note, however, that our lower range of estimates for 3 out of the 5 sources as shown in Table 2 already reflect the use of best technology: 0.3% lower-end estimate for routine venting and leaks at well sites (GAO 2010), 0% lower-end estimate for emissions during liquid unloading, and 0% during processing.

Methane emissions during the flow-back period in theory can be reduced by up to 90% through Reduced Emission Completions technologies, or REC (EPA 2010). However, REC technologies require that pipelines to the well are in place prior to completion, which is not always possible in emerging development areas. In any event, these technologies are currently not in wide use (EPA 2010).

If emissions during transmission, storage, and distribution are at the high end of our estimate (3.6%; Table 2), these could probably be reduced through use of better storage tanks and compressors and through improved monitoring for leaks. Industry has shown little interest in making the investments needed to reduce these emission sources, however (Percival 2010).

Better regulation can help push industry towards reduced emissions. In reconciling a wide range of emissions, the GAO (2010) noted that lower emissions in the Piceance basin in Colorado relative to the Uinta basin in Utah are largely due to a higher use of low-bleed pneumatics in the former due to stricter state regulations.

8 Conclusions and implications

The GHG footprint of shale gas is significantly larger than that from conventional gas, due to methane emissions with flow-back fluids and from drill out of wells during well completion. Routine production and downstream methane emissions are also large, but are the same for conventional and shale gas. Our estimates for these routine and downstream methane emission sources are within the range of those reported by most other peer-reviewed publications inventories (Hayhoe et al. 2002; Lelieveld et al. 2005). Despite this broad agreement, the uncertainty in the magnitude of fugitive emissions is large. Given the importance of methane in global warming, these emissions deserve far greater study than has occurred in the past. We urge both more direct measurements and refined accounting to better quantify lost and unaccounted for gas.

The large GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over coming decades, if the goal is to reduce global warming. We do not intend that our study be used to justify the continued use of either oil or coal, but rather to demonstrate that substituting shale gas for these other fossil fuels may not have the desired effect of mitigating climate warming.

Finally, we note that carbon-trading markets at present under-value the greenhouse warming consequences of methane, by focusing on a 100-year time horizon and by using out-of-date global warming potentials for methane. This should be corrected, and the full GHG footprint of unconventional gas should be used in planning for alternative energy futures that adequately consider global climate change.

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Life cycle greenhouse gas emissions of Marcellus shale gas

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Abstract
This study estimates the life cycle greenhouse gas (GHG) emissions from the production of Marcellus shale natural gas and compares its emissions with national average US natural gas emissions produced in the year 2008, prior to any significant Marcellus shale development. We estimate that the development and completion of a typical Marcellus shale well results in roughly 5500 t of carbon dioxide equivalent emissions or about 1.8 g CO_2e/MJ of gas produced, assuming conservative estimates of the production lifetime of a typical well. This represents an 11% increase in GHG emissions relative to average domestic gas (excluding combustion) and a 3% increase relative to the life cycle emissions when combustion is included. The life cycle GHG emissions of Marcellus shale natural gas are estimated to be 63–75 g CO_2e/MJ of gas produced with an average of 68 g CO_2e/MJ of gas produced. Marcellus shale natural gas GHG emissions are comparable to those of imported liquefied natural gas. Natural gas from the Marcellus shale has generally lower life cycle GHG emissions than coal for production of electricity in the absence of any effective carbon capture and storage processes, by 20–50% depending upon plant efficiencies and natural gas emissions variability. There is significant uncertainty in our Marcellus shale GHG emission estimates due to eventual production volumes and variability in flaring, construction and transportation.

Keywords: life cycle assessment, greenhouse gases, Marcellus shale, natural gas

S Online supplementary data available from stacks.iop.org/ERL/6/034014/mmedia

1. Introduction

Marcellus shale is a rapidly developing new source of US domestic natural gas. The Appalachian Basin Marcellus shale extends from southern New York through the western portion of Pennsylvania and into the eastern half of Ohio and northern West Virginia (Kargbo *et al* 2010). The estimated basin area is between 140 000 and 250 000 km^2 (Kargbo *et al* 2010), and has a depth ranging from 1200 to 2600 m (US DOE 2009). The shale seam's net thickness ranges from 15 to 60 m (US DOE 2009) and is generally thicker from west to east (Hill *et al* 2004). Figure 1 shows the location of the Marcellus and other shale gas formations in the continental United States.

Shale gas has become an important component of the current US natural gas production mix. In 2009, shale gas was 16% of the 21 trillion cubic feet (Tcf) or 600 million cubic meters (Mm^3) total dry gas produced (US EIA 2011a, 2011b). In 2035, the EIA expects the share to increase to 47% (12 Tcf or 340 Mm^3) of total gas production. The prospect of rapid shale gas development has resulted in interest in expanding

Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Figure 1. Shale gas plays and basins in the 48 states (source: US Energy Information Administration 2011a, available at http://www.eia.gov/oil_gas/rpd/shale_gas.jpg).

natural gas use including increased natural gas fired electricity generation, use as an alternative transportation fuel, and even exporting as liquefied natural gas. To date most shale gas activity has been in the Barnett shale in Texas. However, the immense potential of the Marcellus shale has stimulated increased attention. The shale play has an estimated gas-in-place of 1500 Tcf or 42 000 Mm^3, of which 262–500 Tcf or 7400–14 000 Mm^3 are thought to be recoverable (Hill *et al* 2004, US DOE 2009).

Advancements in horizontal drilling and hydraulic fracturing, demonstrated successfully in the Barnett shale and first applied in the Marcellus shale in 2004, have enabled the recovery of economical levels of Marcellus shale gas. After vertical drilling reaches the depth of the shale, the shale formation is penetrated horizontally with lateral lengths extending thousands of feet to ensure maximum contact with the gas-bearing seam. Hydraulic fracturing is then used to increase permeability that in turn increases the gas flow.

In this study, life cycle greenhouse gas (GHG) emissions associated with the Marcellus shale gas production are estimated. The difference between GHG emissions of natural gas production from unconventional Marcellus gas wells and average domestic wells is considered to help determine the environmental impacts of the development of shale gas resources. The results of this analysis are compared with life cycle GHG emissions of average domestic natural gas pre-Marcellus and imported liquefied natural gas. In addition domestic coal and Marcellus shale for electricity generation are compared. Other environmental issues may also be of concern in the Marcellus shale development, including disruption of natural habitats, the use of water and creation of wastewater as well as the impacts of truck transport in rural areas. However these environmental issues are outside the scope of our analysis and are not addressed in this paper.

In estimating GHG emissions, we include GHG emissions of carbon dioxide, methane and nitrous oxide. We converted the GHG emissions to carbon dioxide equivalents according to the global warming potential (GWP) factors reported by IPCC. We use the 100-year GWP factor, in which methane has a global warming potential (GWP) 25 times higher than carbon dioxide (IPCC 2007).

2. Marcellus shale gas analysis boundaries and functional unit

The boundary of our analysis and the major process steps included in our estimates are shown in figure 2. Final life cycle emission estimates are reported in grams of carbon dioxide equivalent emissions per megajoule of natural gas (g CO_2e/MJ) produced. Each of the individual processes in the natural gas life cycle has an associated upstream supply chain and is included in this study to provide a full assessment of GHG emissions associated with Marcellus shale gas. The sources of GHG emissions considered in the LCA include: emissions from the production and transportation of material involved in the well development activities (such as trucking water); emissions from fuel consumption for powering the drilling and fracturing equipment; methane leaks and fuel combustion emissions associated with gas production, processing, transmission, distribution, and natural gas combustion.

The life cycle of Marcellus shale natural gas begins with a ‘preproduction phase’ that includes the well site investigation, preparation of the well pad including grading and construction of the well pad and access roads, drilling, hydraulic fracturing, and well completion (Soeder and Kappel 2009). After this preproduction phase is completed, the well becomes operational and starts producing natural gas. This natural gas can require additional processing to remove water, CO_2 and/or

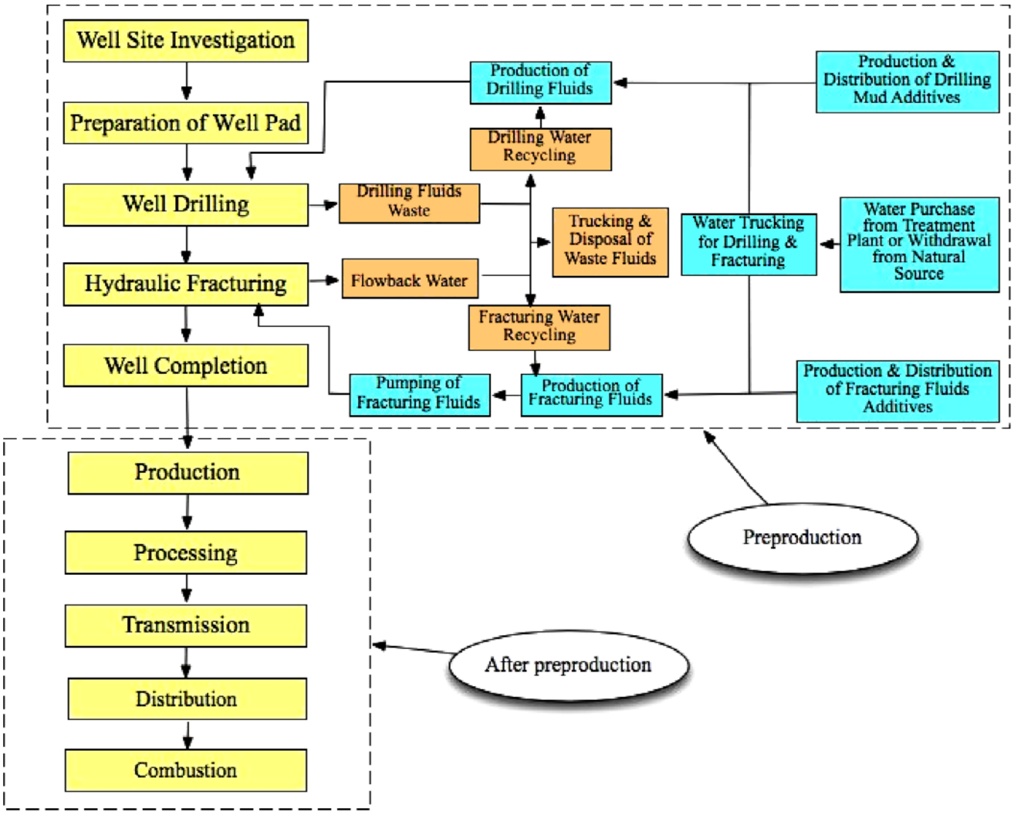

Figure 2. Analysis boundaries and gas production processes.

natural gas liquids before it enters the natural gas transmission and distribution system, which delivers it to final end users. For this work we assume that the GHG emissions for production, transmission, distribution and combustion of Marcellus shale natural gas are similar to average domestic gas sources as estimated by Jaramillo *et al* (2007) and further developed and updated by Venkatesh *et al* (2011).

Finally, natural gas has many current and potential uses including electricity generation, chemical feedstock, and as a transportation fuel. Modeling these uses allows comparisons of different primary energy sources. Here we model its use for power generation since it is the largest single use of natural gas in the US (US EIA 2011a, 2011b).

As previously mentioned, this study integrates GHG emissions from the life cycle of water associated with Marcellus shale gas production. Large amounts of water are consumed in the drilling and hydraulic fracturing processes (preproduction phase). Hydraulic fracturing uses fluid pressure to fracture the surrounding shale. The fracturing fluid consists of water mixed with a number of additives necessary to successfully fracture the shale seam. The source of the water varies and can be surface or ground water, purchased from a local public water supplier, or reused fracturing water. In this study we assume 45% of the water is reused on site and the original sources are surface water (50%) and purchased from a local water treatment plant (50%). Regardless of the water source used to produce the hydraulic fracturing fluid, trucks transport the water for impoundment at the well pad. In addition, flowback water (hydraulic fracturing fluid that returns to the surface) and produced water must be trucked to the final disposal site. This water is assumed to be disposed of via deep well injection. A detailed description of the method and data sources used to estimate the GHG emissions associated with all these stages is presented in section 3.

Marcellus shale gas production is in its infancy. Thus, industry practice is evolving and even single well longevity is unknown. Assumptions related to production rates and ultimate recovery have considerable uncertainty. Below, we include a sensitivity analysis for a wide range of inputs parameters.

This study does not consider any GHG emissions outside of the Marcellus shale gas preproduction and production processes. Natural processes or development actions such as hydraulic fracturing might lead to emissions of the shale gas external to a well, particularly in the case of poorly installed well casings (Osborn *et al* 2011). Any such external leaks are not included in this study.

3. Methods for calculating life cycle greenhouse gas emissions

Our study used a hybrid combination of process activity emission estimates and economic input–output life cycle assessment estimates to estimate the preproduction GHG emission estimates (Hendrickson *et al* 2006, CMU GDI 2010). Emissions from production, processing and transport were adapted from the literature. We include emissions estimates based on different data sources and reasonable

Table 1. Greenhouse gas estimation approaches and data sources.

Process	Estimation approaches	Data sources
Preparation of Well Pad:		
Vegetation clearing	Estimated area cleared multiplied by vegetative carbon storage to obtain carbon loss due to land use change	NY DEC (2009), Tilman *et al* (2006)
Well pad construction	Detailed cost estimate and EIO-LCA model	RSMeans (2005), CMU GDI (2010)
Well drilling:		
Drilling energy consumption	(1) Energy required and emission factor, and (2) cost estimate and EIO-LCA model	Harper (2008), Sheehan *et al* (2000), CMU GDI (2010)
Drilling mud production	(1) Cost estimate and EIO-LCA and (2) emission factors multiplied by quantity.	Shaker (2005), PRé Consultants (2007), CMU GDI (2010)
Drilling water consumption	Trucking emissions plus water treatment emissions multiplied by quantity	Wang and Santini (2009), URS Corporation (2010), PA DEP (2010), Stokes and Horvath (2006)
Hydraulic fracturing:		
Pumping	Pumping energy multiplied by emission factor	URS Corporation (2010), Kargbo *et al* (2010), Currie and Stelle (2010), Sheehan *et al* (2000)
Additives production	Additive quantities cost and EIO-LCA model	URS Corporation (2010), CMU GDI (2010)
Water consumption	Trucking emissions	Wang and Santini (2009), URS Corporation (2010), Stokes and Horvath (2006), PA DEP (2010)
Well completion:	If flaring, gas flow emission factor multiplied by flaring time	NY DEC (2009), PA DEP (2010)
Wastewater disposal:		
Deep well injection	Deep well injection costs and EIO-LCA model	US ACE (2006), CMU GDI (2010)
Production, processing, transmission and storage, and combustion	Assumed comparable to national average	Venkatesh *et al* (2011)

ranges of process parameters. Table 1 summarizes estimation approaches used in this study, while calculation details appear in the supplementary information (available at stacks.iop.org/ERL/6/034014/mmedia).

In section 3.1, we report point estimates of GHG emissions for a base case. In section 5, we report range estimates and consider the sensitivity of point estimates to particular assumptions. Table 2 summarizes important parameter assumptions and possible ranges. Uniform or triangular distributions are assigned to these parameters based on whether we had two (uniform) or three (triangular) data points. When more data was available, parameters of probability distributions that best fit the data were estimated. A Monte Carlo analysis was performed using these distributions, to estimate the emissions from the various activities considered in our life cycle model.

3.1. Emissions from Marcellus shale gas preproduction

Horizontal wells are drilled on a multi-well pad to achieve higher cost-effectiveness. It is reported that a Marcellus well pad might have as few as one well per pad and as many as 16, but more typically 6–8 (ICF International 2009, NY DEC 2009, Currie and Stelle 2010). As a base case scenario, we chose to analyze the typical pad with six wells, each producing 2.7 Bcf (3.0×10^9 MJ), representing an average of 0.3 MMcf per day of gas for 25 years. Other production estimates are higher. EQT (2011), for example, provides a production estimate of 7.3 Bcf (8.1×10^9 MJ) and Range Resources at 4.4 Bcf (4.9×10^9 MJ) (Ventura 2009). Within the LCA framework the impacts are distributed across the total volume of gas produced during the lifetime of the well. Thus, the choice of using the low end ultimate recovery as the base case should be considered conservative. With Marcellus shale gas production currently in its infancy, the average production characteristics have significant uncertainty, so we perform an

Table 2. Parameter assumptions and ranges. (Note: sources for base case and range values are in table 1 and discussed in the supplementary material (available at stacks.iop.org/ERL/6/034014/mmedia).)

Parameter	Base case	Range
Area of access road (acres)	1.43	0.1–2.75
Wells per pad (number)	6	1–16
Area of well pad (acres)	5	2–6
Vertical drilling depth (ft)	8500	7000–10 000
Horizontal drilling length (ft)	4000	2000–6000
Fracturing water (MMgal/well)	4	2–6
Flowback fraction (%)	37.5	35–40
Recycling fraction (%)	45	30–60
Trucking distance between well site and water source (miles)	5	0–10
Trucking distance between well site and deep well injection facility (miles)	80	3–280
Well completion time with collection system in place (h)	18	12–24
Well completion time without collection system in place (days)	9.5	4–15
Fraction of flaring (%)	76	51–100
Initial 30 day gas flow rate (MMscf/day)	4.1	0.7–10
Average well production rate (MMscf/day)	0.3	0.3–10
Well lifetime (years)	25	5–25

extensive sensitivity analysis over a range of flow rates and well lifetimes, as discussed below.

The EIO-LCA (CMU GDI 2010) model was used to estimate GHG emissions from the construction of the access road and the multi-well pad. These costs were estimated using the utility price cost estimation method (RSMeans 2005). The size of an average Marcellus well pad is reported as being between 2 and 6 acres and typically between 4 and 5 acres (16 000 and 20 000 m^2) during drilling and fracturing phase (NY DEC 2009, Columbia University 2009). The costs of constructing this pad are estimated to be \$3.0–\$3.3 million per well pad in 2002 dollars (see the supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for detail). Using these costs as input, GHG emissions associated with well pad construction are estimated with the EIO-LCA (CMU GDI 2010) model.

Greenhouse gas emissions associated with drilling operations were calculated by two methods; (1) using the drilling energy intensity (table 1) and the life cycle diesel engine emissions factor of 635 g CO_2e per hp–hr output (Sheehan *et al* 2000), and (2) using drilling cost data and the EIO-LCA model (CMU GDI 2010). The EIA estimated the average drilling cost for natural gas wells in 2002 to be \$176 per foot (including the cost for drilling and equipping the wells and for surface producing facilities) (US EIA 2008). Emissions associated with the production of the drilling mud components were based on data from the SimaPro life cycle tool and the EIO-LCA economic model (PRé Consultants 2007, CMU GDI 2010).

Hydraulic fracturing associated GHG emissions result from the operation of the diesel compressor used to move and compress the fracturing fluid to high pressure, the emissions associated with the production of the hydraulic fracturing fluid, and from fugitive methane emissions as flowback water is captured. The last category of emissions is discussed separately below. Energy and emissions associated with the hydraulic fracturing process were modeled by using vendor specific diesel data along with the emission factor described above. The emissions of hydraulic fracturing fluid production are estimated with EIO-LCA model, based on the price of additives and fracturing fluid composition (see supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for detail).

There may be significant GHG emissions as a result of flaring and venting activities that occur during well casing and gathering equipment installation. The natural gas associated with the hydraulic fracturing flowback water is flared and vented. Flaring is used for testing the well gas flow prior to the construction of the gas gathering system which transport the gas to the sales line. Well completion emissions depend on the flaring/venting time, gas flow rate during well completion, the ratio of flaring to venting, and flaring efficiency. Uncertainty/variability analysis was conducted to investigate the effect of flaring/venting time, gas flow rate during fracturing water flowback, and flaring per cent on the well completion emissions. For those well completions with the collection facilities in place, gas is flared for between 12 and 24 h, due to necessary flowback operations. In wells where the appropriate gas gathering system as a tie to the gas sales line is not available for the gas during fracturing water flowback, the flaring or venting can occur for between 4 and 15 days as shown in table 2 (NY DEC 2009). In our model, we assumed the gas release rate during well completion equals the initial 30 day gas production rate for the base case and considered a scenario with both venting and flaring (see supplementary information available at stacks.iop.org/ERL/6/034014/mmedia for details).

3.2. Emissions from Marcellus shale gas production to combustion

GHG emissions for production, processing, transmission, distribution and combustion of Marcellus shale natural gas are assumed to be similar to the US average domestic gas system that have been estimated previously (Jaramillo *et al* 2007). Jaramillo *et al* (2007) estimates were updated to include the uncertainty and variability in life cycle estimates and recalculated with recent and/or more detailed information by Venkatesh *et al* (2011). The GHG emissions from these life cycle stages consist of vented methane (gas release during operation), fugitive methane (unintentional leaks) and CO_2 emissions from the processing plants and from fuel consumption. Methane leakage rates throughout the natural gas system (excluding the preproduction processes previously discussed) are a major concern and our analysis has an implied fugitive emissions rate of 2%, consistent with the EPA natural gas industry study (US EPA 1996, 2010).

Venkatesh *et al* (2011) estimated the mean emission factors used in this study: 9.7 g CO_2e/MJ of natural gas in production; 4.3 g CO_2e MJ for processing; 1.4 g CO_2e/MJ for transmission and storage; 0.8 g CO_2e/MJ for distribution; and 50 g CO_2e/MJ for combustion.

3.3. Emissions associated with the life cycle of water used for drilling and hydraulic fracturing

Water resource management is a critical component of the production of Marcellus shale natural gas. Chesapeake Energy (2010) indicates that 100 000 gallons of water are used for drilling mud preparation. Two to six million gallons of water per well are required for the hydraulic fracturing process (Staaf and Masur 2009). About 85% of the drilling mud is reused (URS Corporation 2010). The flowback and recycling rates are used to estimate the total volume of water required. About 60–65% of this hydrofracturing fluid is recovered (URS Corporation 2010). For the flowback water, a recycle rate from 30 to 60% can be achieved (Agbaji *et al* 2009). The rest of the flowback water is temporarily stored in the impoundment and transported off site for disposal. Base case assumptions for these parameters are shown in table 2.

Emissions associated with drilling water use and hydraulic fracturing water use result from water taken from surface water resources or a local public water system; truck transport to the well pad, and then from the pad to disposal via deep well injection. It is assumed that no GHG emissions are related

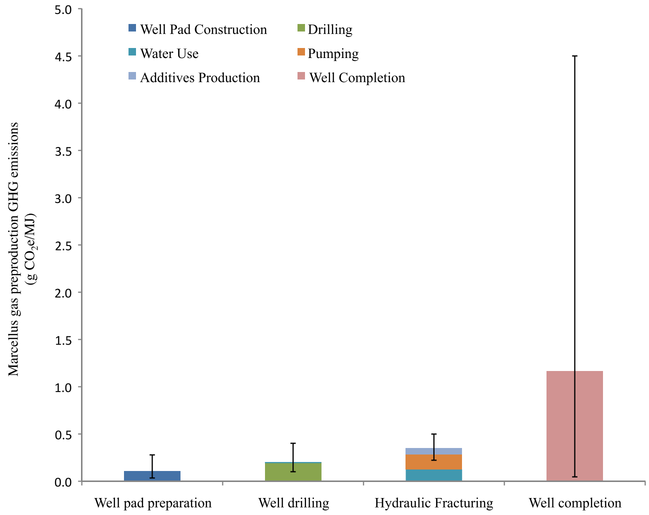

Figure 3. GHG emissions from different stages of Marcellus shale gas preproduction.

with producing water if it comes from surface water resources. For the water purchased from a local public water system, the emission factor for water treatment is used, which is estimated to be 3.4 g CO_2e/gallon of water generated according to Stokes and Horvath (2006). The energy intensity for transportation of liquids via truck is assumed to be 1028 Btu/ton mile for both forward and back-haul trips, as given in the GREET model (Wang and Santini 2009). In this study we assume that separate round trips are needed to transport the freshwater to the pad and to remove wastewater to the disposal site. This is to say that trucks bring in the freshwater from the source and return to the source empty; trucks also collect the wastewater from the well site and return to the well site empty. The life cycle emission factor (wells to wheels) for diesel as a transportation fuel is 93 g CO_2e/MJ (Wang and Santini 2009).

To estimate transport emissions associated with water taken from surface streams and water purchased from the local public water system, we used spatial analysis (ArcGIS) to estimate the distance from the surface water source to the well pad using well operational data and geographical information from Pennsylvania Department of Environmental Protection (2010). We depicted the overall distribution pattern of Marcellus wells under drilling and production in PA and NY in June 2010 by GIS. The distance from the well site to the surface water source is assumed to be 5 miles or 8 km in the base case of the model and the same transportation distance is also assumed for the water purchased from local public water system. We assumed an equal probability for sourcing water between surface water and the local public water system.

The trucking distance between well site and deep well injection facility was also estimated by GIS (PA DEP 2010). The average value of 80 miles or 130 km as determined by GIS was used in the base case.

4. Results for the base case

A total of 5500 t CO_2e is emitted during 'preproduction' per well. This is equivalent to 1.8 g CO_2e/MJ of natural gas produced over the lifetime of the well. Figure 3 depicts the GHG emissions by preproduction stage and by source. As can be seen, the completion stage has the largest GHG emissions, which result from flaring and/or venting. The error bars represent the limits of the 90% confidence interval of the emissions from each stage based on the uncertainty analysis.

A recent EPA report addressing emissions from the natural gas industry reported that 177 t of CH_4 is released during the completion of an unconventional gas well (US EPA 2010). This estimate is consistent with the analysis here and falls within the range estimated by our study, 26–1000 t of CH_4 released per completion and a mean value of 400 t of CH_4 released per completion. In our model, this methane released during the well completion is either flared with a combustion efficiency of 98% or vented without recovery.

Adding the preproduction emissions estimate to the downstream emission estimated by Venkatesh *et al* (2011) results in an overall GHG emissions factor of 68 g CO_2e/MJ of gas produced (figure 4). The life cycle emissions are dominated by combustion that accounts for 74% of the total emissions.

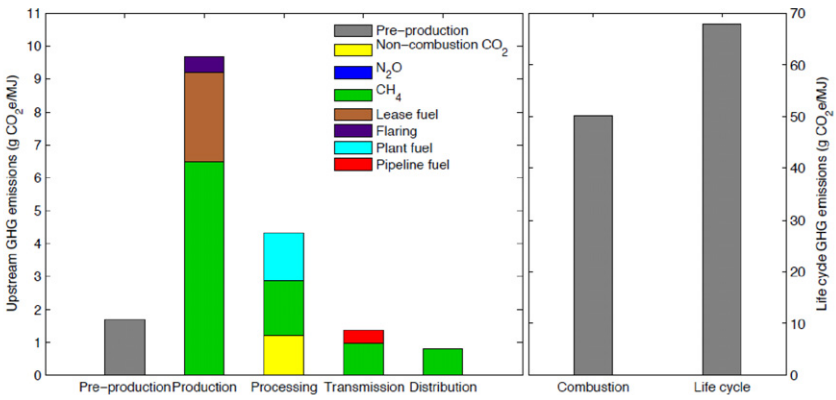

Figure 4. GHG emissions through the life cycle of Marcellus shale gas. (Preproduction through distribution emissions are on left scale; combustion and total life cycle emissions are on right scale. No carbon capture is included after combustion.)

Table 3. Uncertainty analysis on Marcellus gas preproduction.

Life cycle stage	Mean ($g\ CO_2e/MJ$)	Standard deviation ($g\ CO_2e/MJ$)	COV	90% CI-L (%)	90% CI-U (%)
Well pad preparation	0.13	0.1	0.72	58	131
Drilling	0.21	0.1	0.50	51	95
Hydraulic fracturing	0.35	0.1	0.24	37	42
Completion	1.15	1.8	1.53	96	287
Total	1.84	1.8	0.96	67	179

Table 4. Sensitivity of emissions from wells with different production rates and lifetimes. (Source: author calculations.)

Average gas flow (MMscf/day)	Lifetime (years)	Emissions from preproduction ($g\ CO_2e/MJ$)	Preproduction % contribution to life cycle emissions of Marcellus shale gas (%)	Total life cycle emissions ($g\ CO_2e/MJ$)
10	25	0.1	0.1	65.3
10	10	0.1	0.2	65.3
10	5	0.3	0.4	65.5
3	25	0.2	0.3	65.4
3	10	0.5	0.7	65.7
3	5	0.9	1.4	66.1
1	25	0.6	0.8	65.8
1	10	1.4	2.1	66.6
1	5	2.8	4.1	68.0
0.3	25	1.8	2.7	67.0
0.3	10	5	6.6	69.8
0.3	5	9.2	12.4	74.4

5. Sensitivity and uncertainty

Our results are subject to considerable uncertainty, particularly for the production rates and well lifetime. Table 3 summarizes the uncertainty analysis on the emission estimates for preproduction based on the distribution of parameters used.

Table 4 addresses model sensitivity to different estimates of ultimate gas recovery from wells, investigating the impact of different production rates and lifetimes. At high production rates and long well lifetimes the preproduction GHG emissions are normalized over higher volumes of natural gas than when using low flow rates and short well lifetimes. Comparing the case of 10 MMscf/day with a 25-year well lifetime to 0.3 MMscf/day with a 5-year well lifetime, table 4 shows that the emissions go from 0.1 to 9.2 g CO_2e/MJ. The overall life cycle emissions change from 65 to 74 g CO_2e/MJ. However, the preproduction emissions are less than 15% of the total life cycle emissions in all cases.

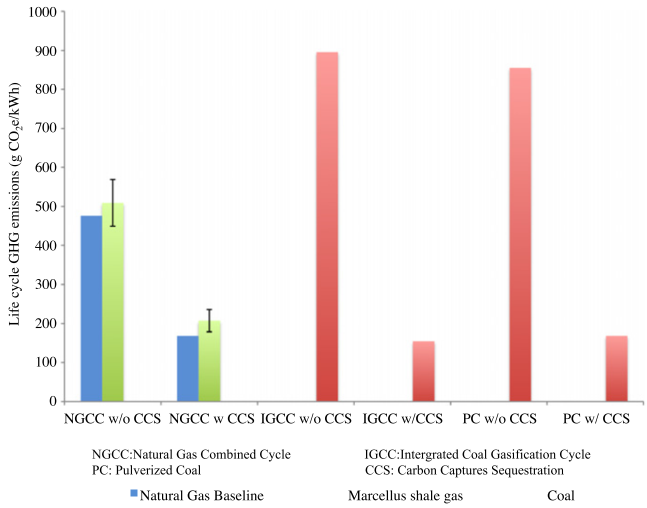

Figure 5. Comparison of life cycle GHG emissions from current domestic natural gas, Marcellus shale gas and coal for use in electricity production.

6. Comparison with coal for power generation

Marcellus shale gas emissions can be compared to alternative energy sources and processes when using a common metric such as electricity generated. Currently coal power plants are used to generate base load. Natural gas power plants, especially inefficient ones, are used to provide regulation services to balance supply and demand at times when base load power plants are insufficient or there is high-frequency variability in load or from renewable resources. Natural gas combined cycle (NGCC) plants could be used to generate base load thus competing directly with coal to provide this service. For this reason our comparison includes the emissions associated with using Marcellus shale gas in a NGCC power plant (efficiency of 50%) and the emissions from using coal in pulverized coal (PC) plants (efficiency of 39%) and integrated gasification combined cycle (IGCC) plants (efficiency of 38%). The results of these comparisons can be seen in figure 5. For this comparison point values are used for the life cycle GHG emissions of coal-based electricity. The error bars found in figure 5 represent the low and high emissions values for Marcellus shale gas, based on the assumptions of well production rate and well lifetime. The high-emission scenario assumes a 5-year well with 0.3 MMscf/day production rate while the low-emission scenario, assumes a 25-year well with 10 MMscf/day production rate. Also shown in figure 5 are the life cycle emissions of electricity generated in power plants with carbon capture and sequestration (CCS) capabilities (efficiency of 43% for NGCC with CCS; efficiency of 30% for PC with CCS; efficiency of 33% for ICGG with CCS).

In general, natural gas provides lower greenhouse emission for all cases studied whether the gas is derived from Marcellus shale or the average 2008 domestic natural gas system. When advanced technologies are used with CSS then the emissions are similar and coal provides slightly less emissions. This implies that the upstream emissions for natural gas life cycle are higher than the upstream emissions from coal, once efficiencies of power generation are taken into account (Jaramillo *et al* 2007).

The comparison of natural gas and coal for electricity allows us to investigate the impact of three additional model uncertainty components including the choice of leakage rate, GWP values, and re-refracking of a Marcellus gas well. This study assumes a 2% production phase leakage rate based on the volume of gas produced (US EPA 2010, Venkatesh *et al* 2011). Assuming the average efficiency of 43% for natural gas fired electricity generation and 32% for coal fired plants the fugitive emissions rate would need to be 14% (resulting in a life cycle emission factor for Marcellus gas of 125 g CO_2e/MJ) before the overall life cycle emissions including those of electricity generation would be greater than coal. This is an exorbitantly high leakage rate and to put it into perspective, using 2009 dry natural gas production estimates and the average wellhead price, we calculate that the economic losses a would total around $11 billion. If we convert our data to the 20-year GWP the break-even point is reduced to 7% because of the higher impacts attributed to methane. Finally, we modeled a single hydraulic fracturing event occurring during well preproduction (figure 3). Above we calculated that the break-even emission factor that would make coal and natural electricity generation the same is 125 g CO_2e/MJ of natural gas. With the current emissions estimate for Marcellus gas of 68 g CO_2e/MJ, and a hydraulic fracturing event (and its associated flaring and venting emissions) contributing 1.5 g CO_2e/MJ to this estimate, more than 25 fracturing events would need to occur in a single well before the decision between coal and natural gas would change.

7. Comparison with liquefied natural gas as a future source

In 2005 EIA suggested that domestic natural gas production and Canadian imports would decline as natural gas consumption increased. EIA predicted that liquefied natural gas (LNG) imports would grow to offset the deficits in North American production (US EIA 2011a, 2011b). As a result of the development of unconventional natural gas reserves, EIA has changed their projections. The Annual Energy Outlook 2011 reference case (US EIA 2011a, 2011b) predicts that increases in shale gas production, including Marcellus, will more than offset the decline in conventional natural gas and decreasing imports from Canada and will allow for increases in natural gas consumption. Since shale gas is projected to be the largest component of the unconventional sources of future natural gas production, it seem appropriate to compare its emissions to those of the gas that would be used if shale gas were not produced. Venkatesh *et al* (2011) estimated the life cycle GHG from LNG imported to the US to have a mean of 70 g CO_2e/MJ, These results are based on emissions due to production and liquefaction in the countries of origin, shipping the gas to the US by ocean tanker, regasification in the US and its transmission, distribution and subsequent combustion. On average, the emissions of Marcellus shale gas were about 3% lower than LNG. As with the overall Marcellus gas results, there is considerable uncertainty to the comparisons. However, we conclude that as these unconventional sources of natural gas supplant LNG imports, overall emissions will not rise.

8. Conclusion

The GHG emission estimates shown here for Marcellus gas are similar to current domestic gas. Other shale gas plays could generate different results considering regional environmental variability and reservoir heterogeneity. Green completion and capturing the gas for market that would otherwise be flared or vented, could reduce the emissions associated with completion and thus would significantly reduce the largest source of emissions specific to Marcellus gas preproduction. These preproduction emissions, however, are not substantial contributors to the life cycle estimates, which are dominated by the combustion emissions of the gas. For comparison purposes, Marcellus shale gas adds only 3% more emissions to the average conventional gas, which is likely within the uncertainty bounds of the study. Marcellus shale gas has lower GHG emissions relative to coal when used to generate electricity.

Acknowledgments

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NATIONAL ENERGY TECHNOLOGY LABORATORY

Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States

Timothy J. Skone, P.E.

Office of Strategic Energy Analysis and Planning

May 12, 2011

Presented at: Cornell University Lecture Series

U.S. DEPARTMENT OF ENERGY

Overview

1. Who is NETL?
2. What is the role of natural gas in the United States?
3. Who uses natural gas in the U.S.?
4. Where does natural gas come from?
5. What is the life cycle GHG footprint of domestic natural gas extraction and delivery to large end-users?
6. How does natural gas power generation compare to coal-fired power generation on a life cycle GHG basis?
7. What are the opportunities for reducing GHG emissions?

Question #1:

Who is NETL?

National Energy Technology Laboratory

MISSION
Advancing energy options to fuel our economy, strengthen our security, and improve our environment

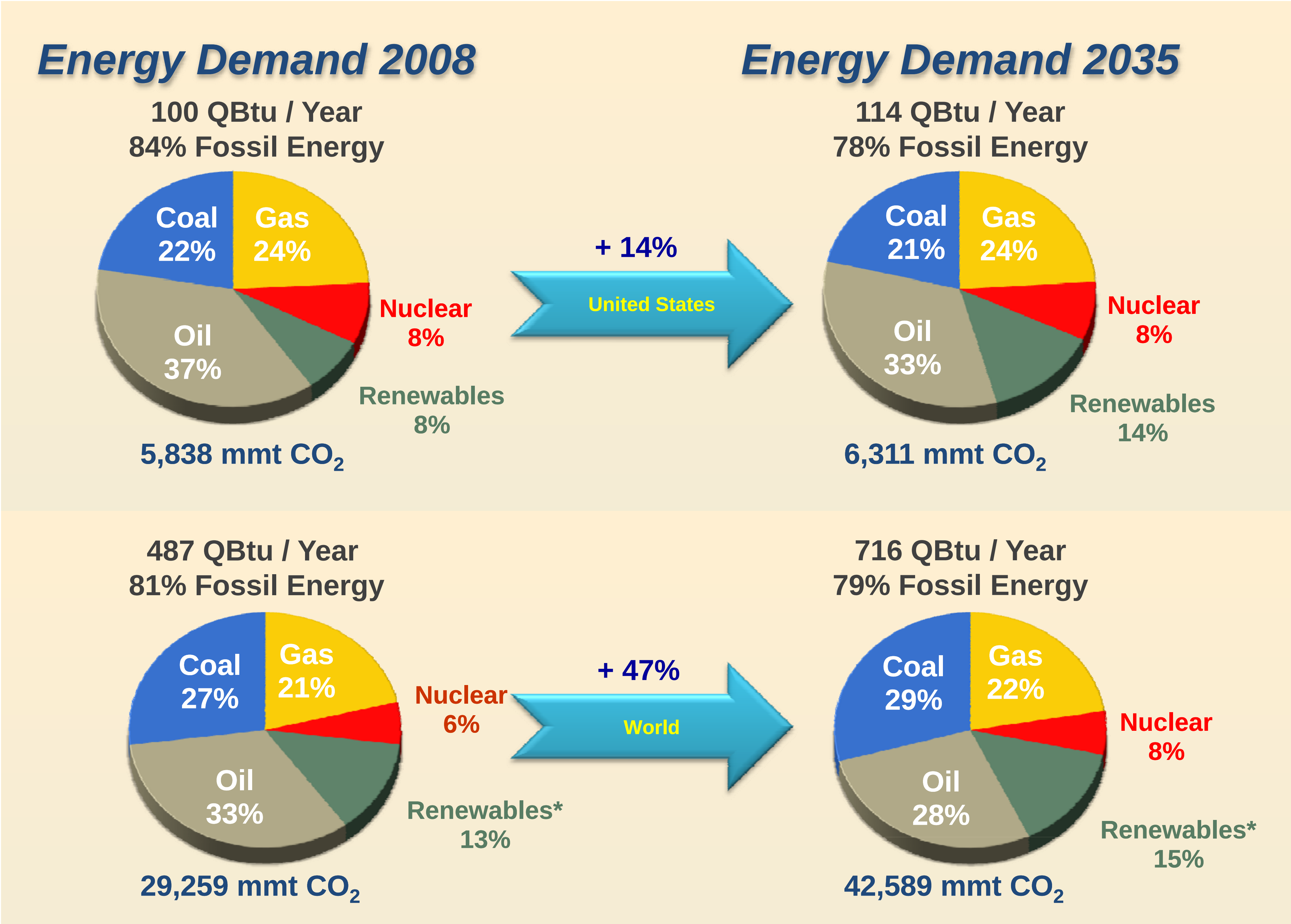
Oregon

Pennsylvania

West Virginia

Question #2:

What is the role of natural gas in the United States?



Sources: U.S. data from EIA, Annual Energy Outlook 2011; World data from IEA, World Energy Outlook 2010, Current Policies Scenario

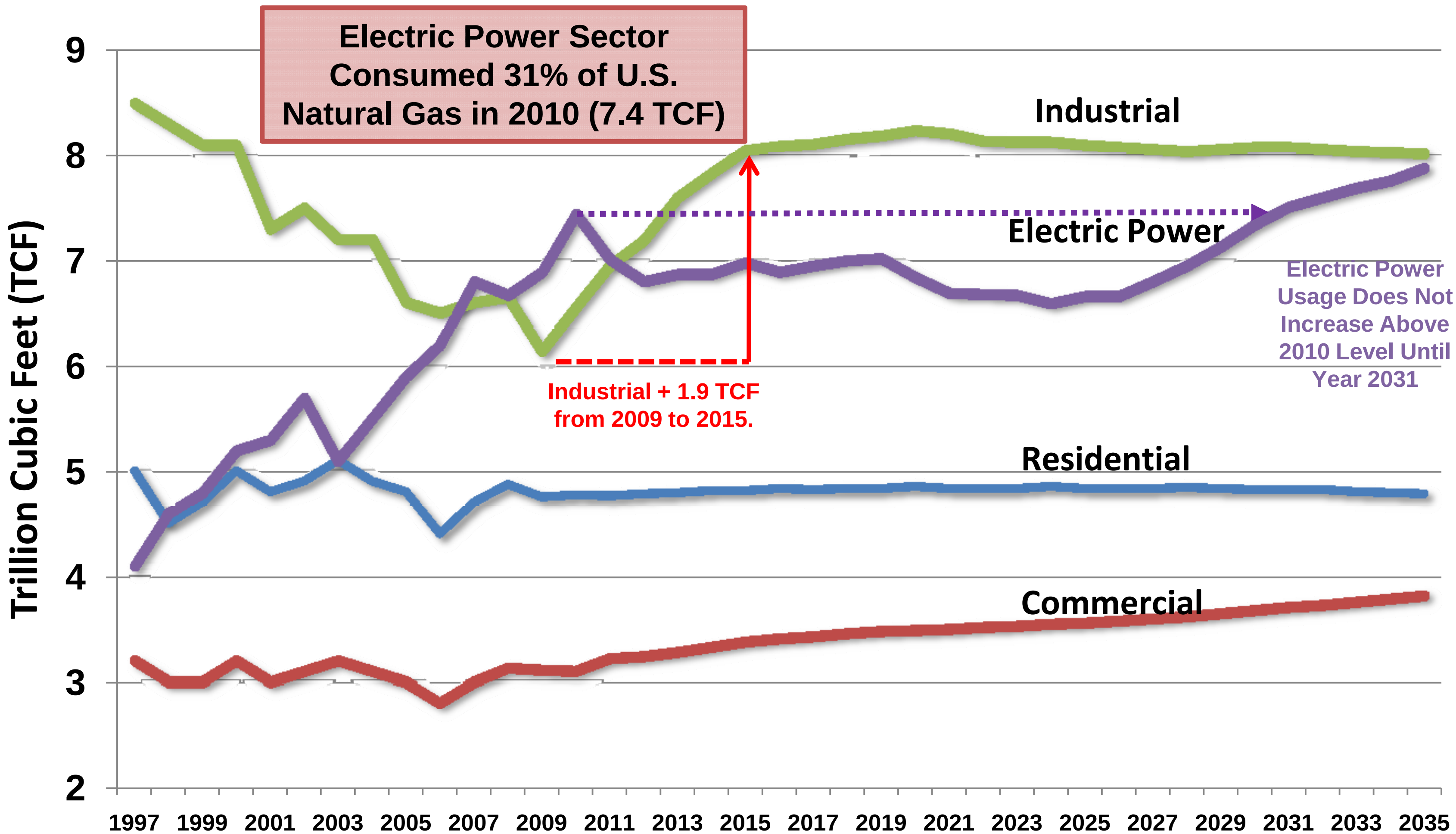
* Primarily traditional biomass, wood, and waste.

Question #3:

Who uses natural gas in the United States?

Domestic Natural Gas Consumption

Sectoral Trends and Projections: 2010 Total Consumption = 23.8 TCF



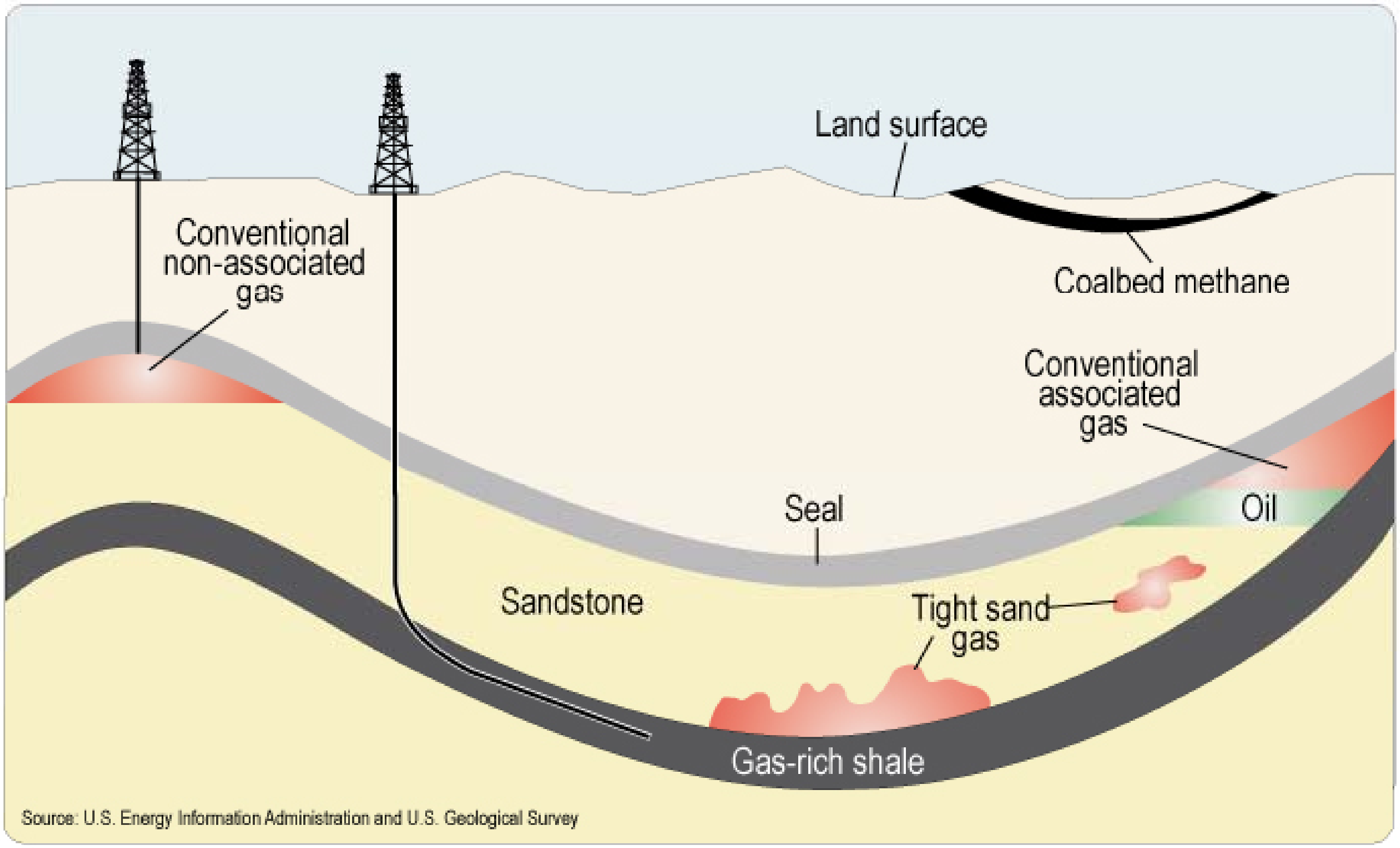
+1.9 TCF Resurgence in Industrial Use of Natural Gas by 2015 Exceeds the Net Incremental Supply; No Increase in Natural Gas Use for Electric Power Sector Until 2031

Source: EIA Annual Energy Review 2009 and Annual Energy Outlook 2011

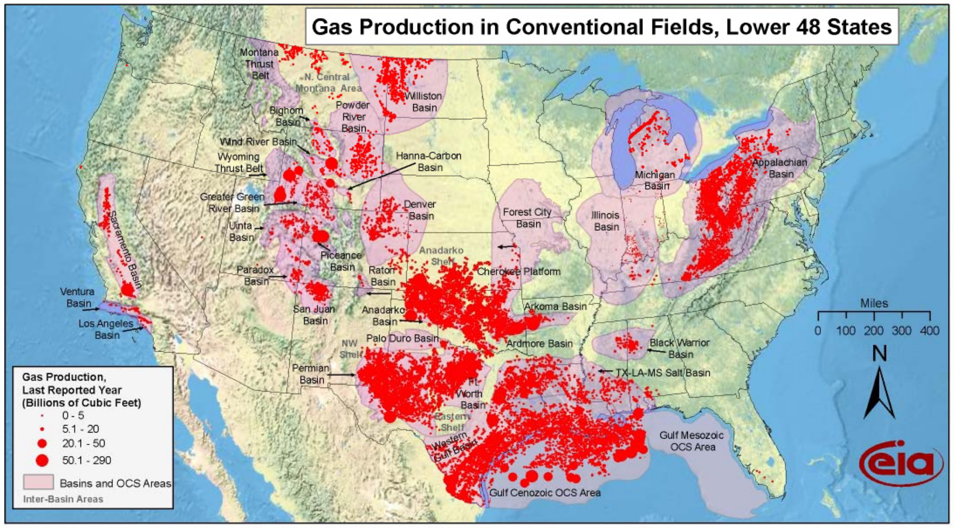
<u>Question #4:</u>

Where does natural gas come from?

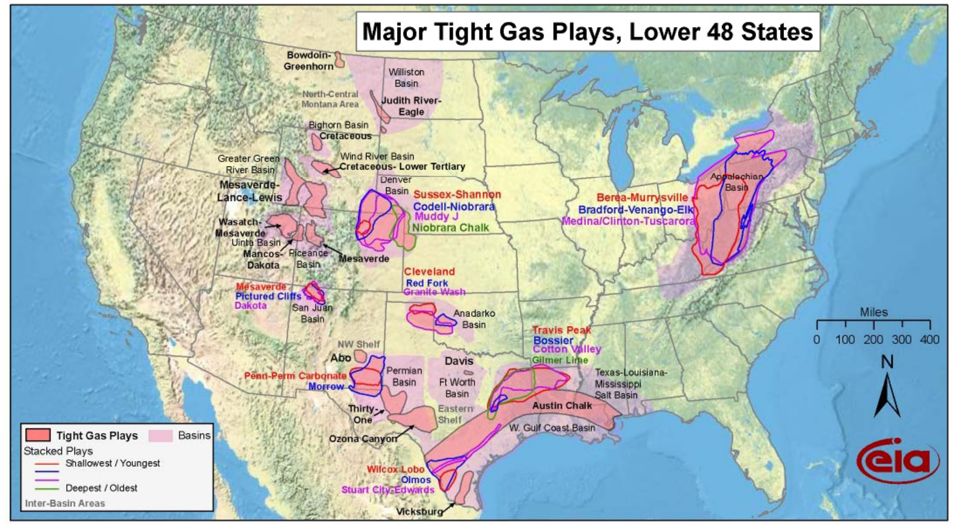
Schematic Geology of Onshore Natural Gas Resources



Source: EIA, Today in Energy, February 14, 2011; Modified USGS Figure from Fact Sheet 0113-01; www.eia.doe.gov/todayinenergy/detail.cfm?id=110 Last Accessed May 5, 2011.



Source: Energy Information Administration based on data from HPDI, IN Geological Survey, USGS
Updated: April 8, 2009



Source: Energy Information Administration based on data from various published studies
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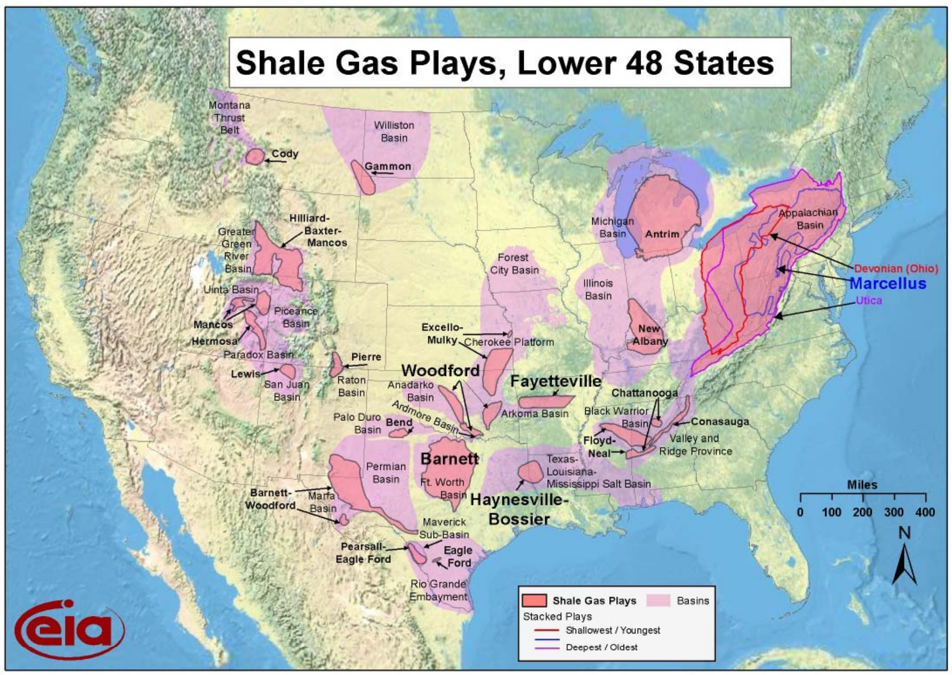
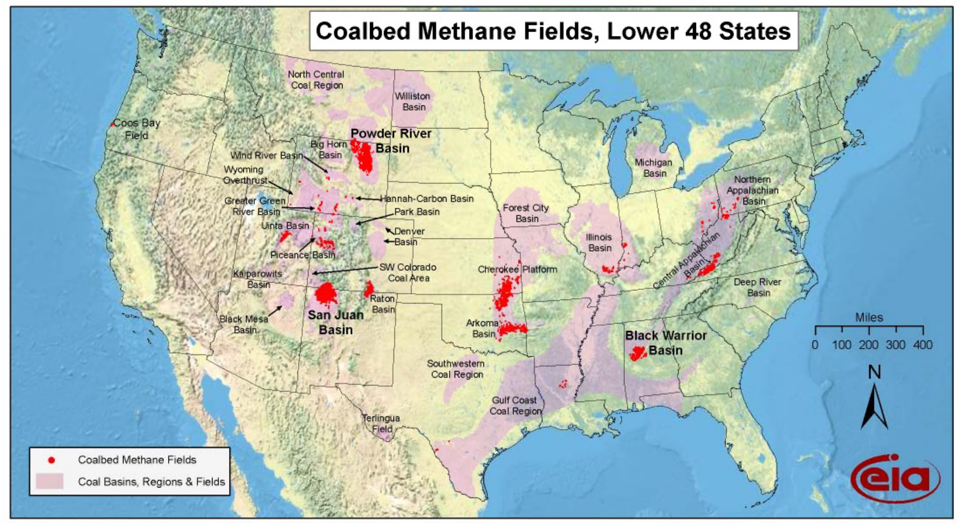


Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010



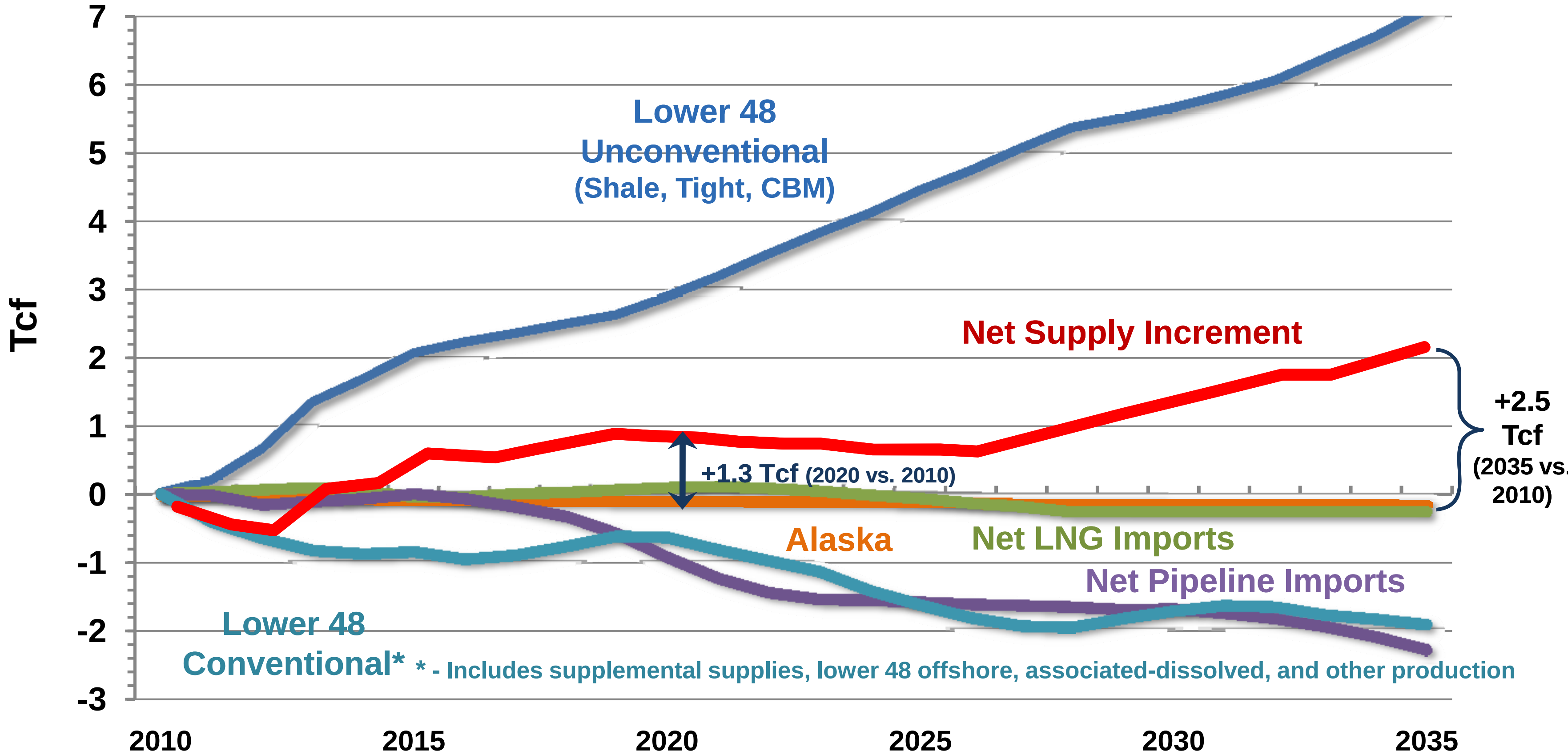
Source: Energy Information Administration based on data from USGS and various published studies
Updated: April 8, 2009

EIA Natural Gas Maps

Source: EIA, Natural Gas Maps, http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm Last Accessed May 5, 2011.

Sources of Incremental Natural Gas Supply

(Indexed to 2010)



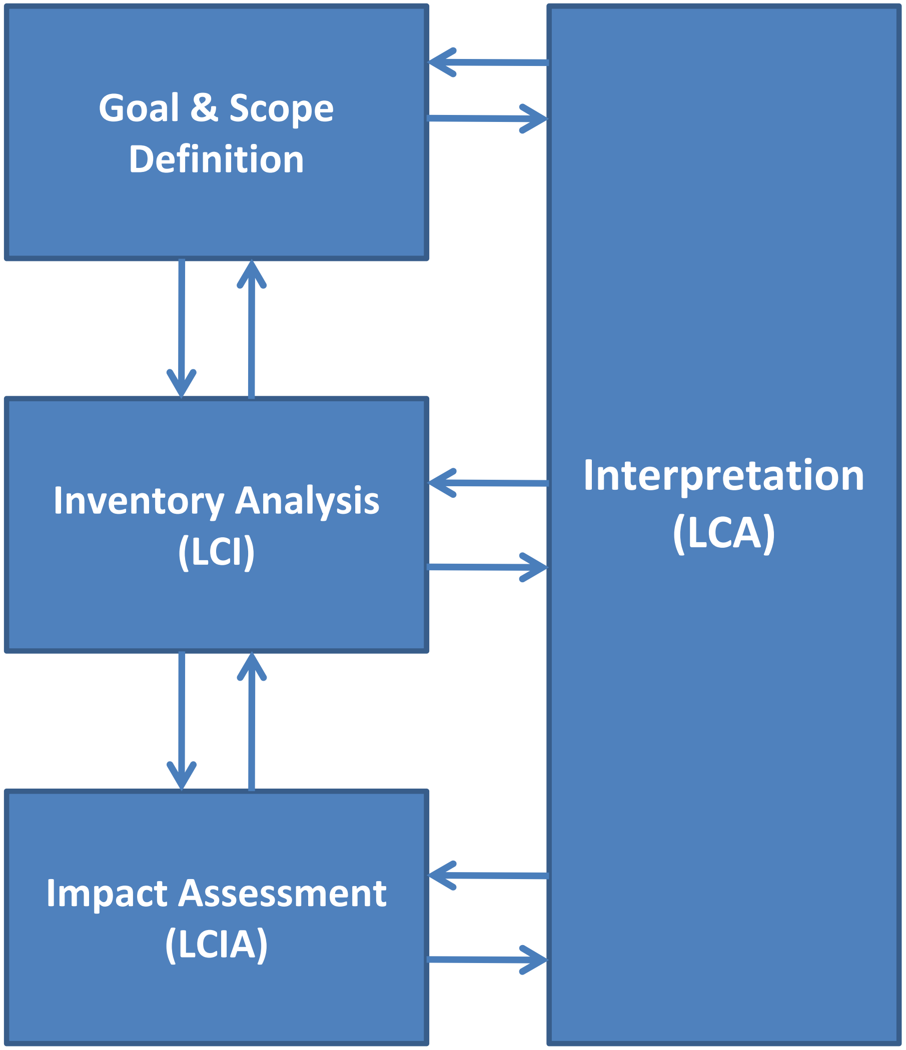
Unconventional Production Growth Offset by Declines in Conventional Production and Net Pipeline Imports; 1.3 Tcf Increment by 2020 Does Not Support Significant Coal Generation Displacement

Source: EIA, Annual Energy Outlook 2011

Question #5:

What is the life cycle GHG footprint of domestic natural gas extraction and delivery to large end-users?

Overview: Life Cycle Assessment Approach



Source: ISO 14040:2006, Figure 1 – Stages of an LCA (reproduced)

<u>The Type of LCA Conducted Depends on Answers to these Questions:</u>

1. What Do You Want to Know?

2. How Will You Use the Results?

<u>International Organization for Standardization (ISO) for LCA</u>

- ISO 14040:2006 Environmental Management – Life Cycle Assessment – Principles and Framework
- ISO 14044 Environmental Management – Life Cycle Assessment – Requirements and Guidelines
- ISO/TR 14047:2003 Environmental Management – Life Cycle Impact Assessment – Examples of Applications of ISO 14042
- ISO/TS 14048:2002 Environmental Management – Life Cycle Assessment – Data Documentation Format

Overview: Life Cycle Assessment Approach

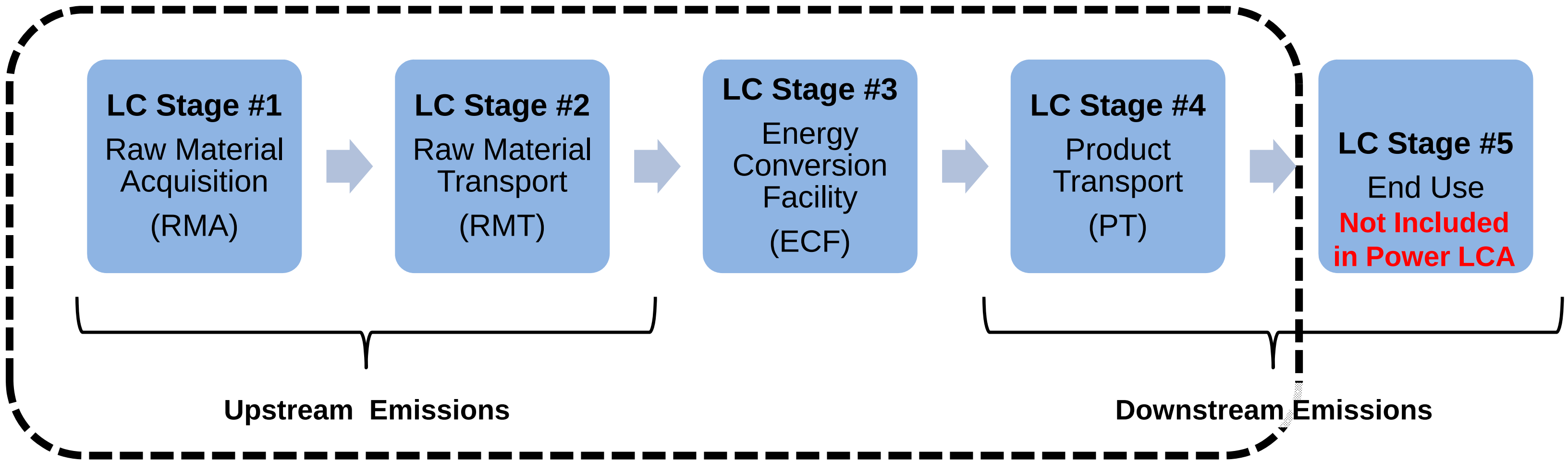
The Type of LCA Conducted Depends on Answers to these Questions :

1. **What Do You Want to Know?**
   - ❑ **The GHG footprint of natural gas, lower 48 domestic average, extraction, processing, and delivery to a large end-user (e.g., power plant)**
   - ❑ **The comparison of natural gas used in a baseload power generation plant to baseload coal-fired power generation on a lbs CO_2e/MWh basis**

2. **How Will You Use the Results?**
   - ❑ **Inform research and development activities to reduce the GHG footprint of both energy feedstock extraction and power production in existing and future operations**

NETL Life Cycle Analysis Approach

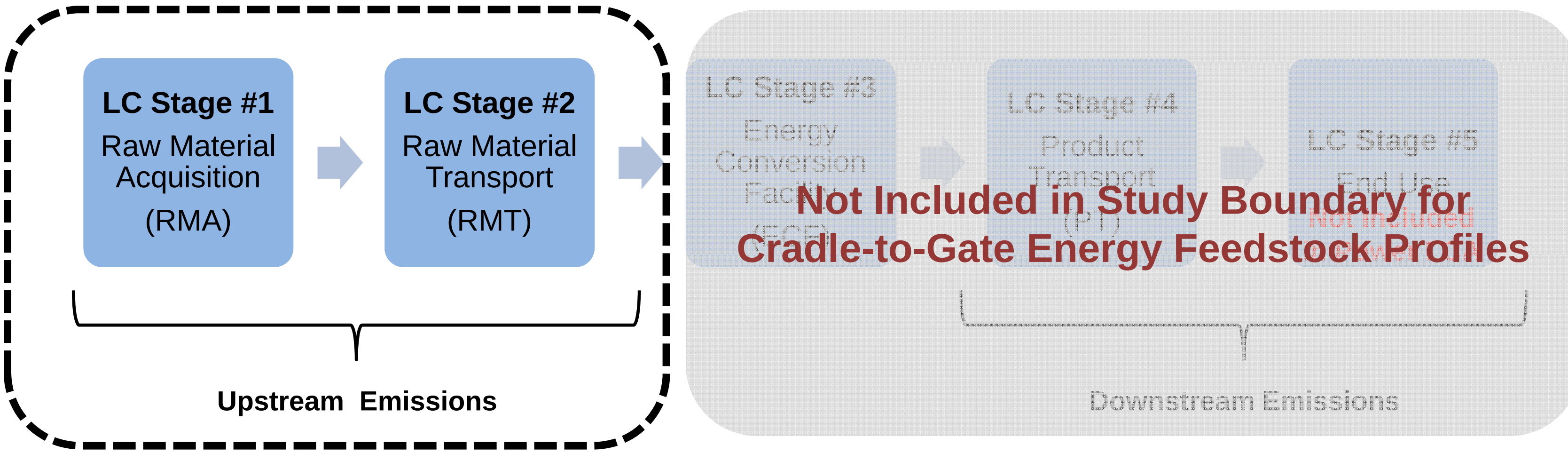
- **Compilation and evaluation of the inputs, outputs, and the potential environmental impacts of a product or service throughout its life cycle, from raw material acquisition to the final disposal**



- **The ability to compare different technologies depends on the functional unit (denominator); for power LCA studies:**
  - 1 MWh of electricity delivered to the end user

NETL Life Cycle Analysis Approach for Natural Gas Extraction and Delivery Study

- **The study boundary for “domestic natural gas extraction and delivery to large end-users” is represented by Life Cycle (LC) Stages #1 and #2 only.**



- **Functional unit (denominator) for energy feedstock profiles is:**
  - 1 MMBtu of feedstock delivered to end user
    (MMBtu = million British thermal units)

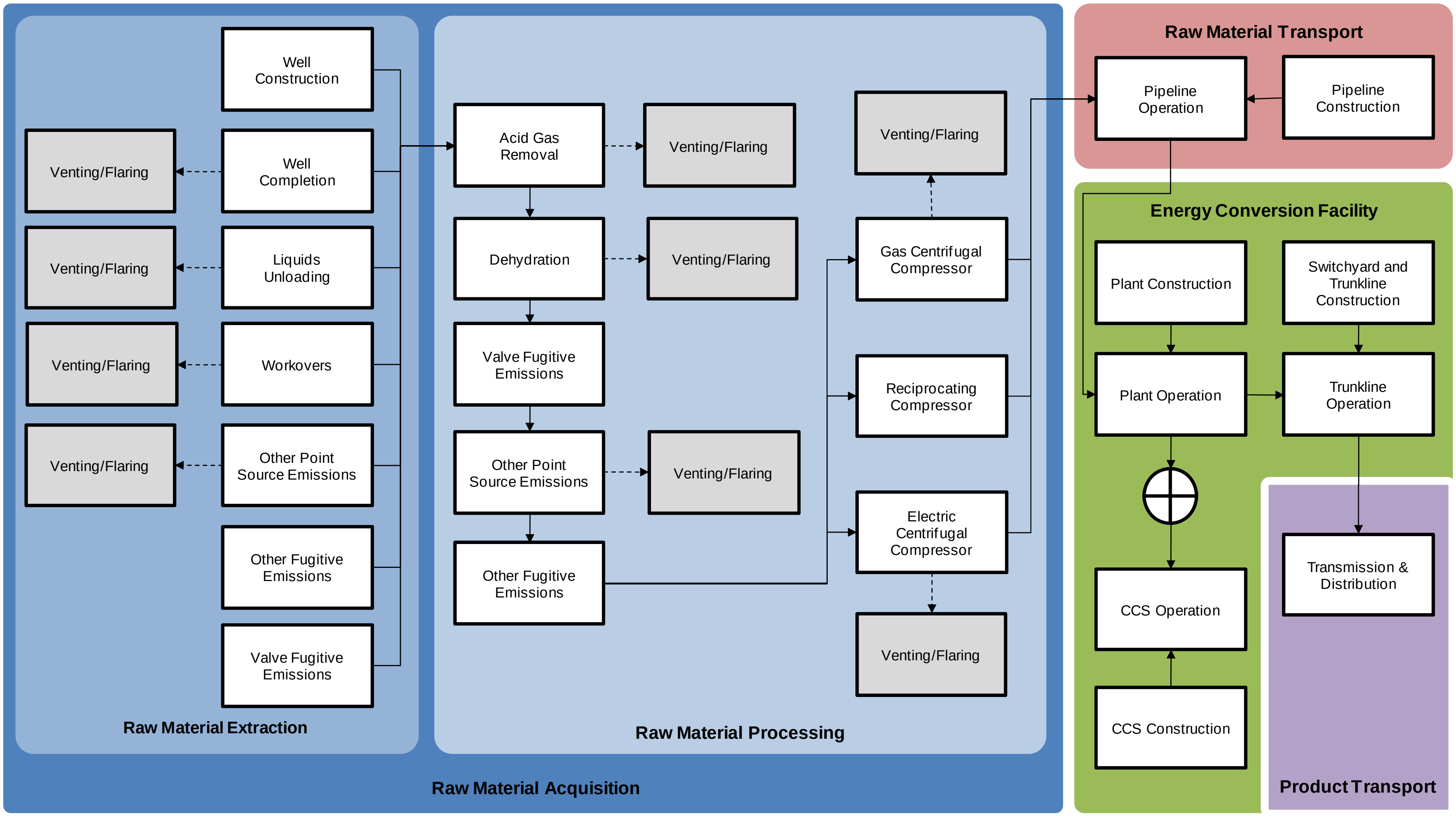
NETL Life Cycle Study Metrics

- **Greenhouse Gases**
  - CO_2, CH_4, N_2O, SF_6
- **Criteria Air Pollutants**
  - NO_X, SO_X, CO, PM10, Pb
- **Air Emissions Species of Interest**
  - Hg, NH_3, radionuclides
- **Solid Waste**
- **Raw Materials**
  - Energy Return on Investment
- **Water Use**
  - Withdrawn water, consumption, water returned to source
  - Water Quality
- **Land Use**
  - Acres transformed, greenhouse gases

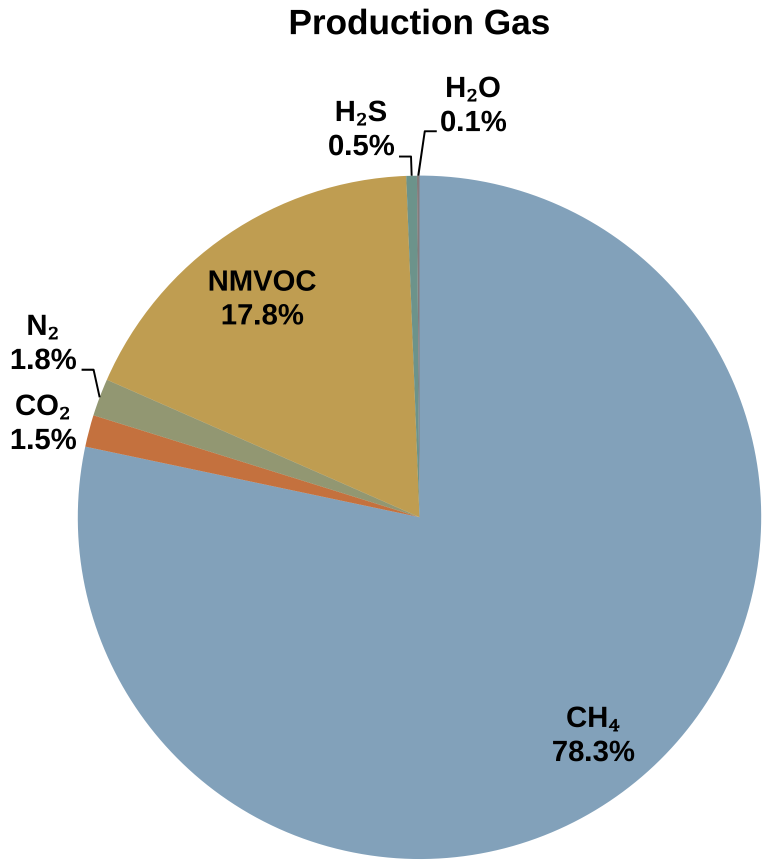
Converted to Global Warming Potential using IPCC 2007 100-year CO_2 equivalents

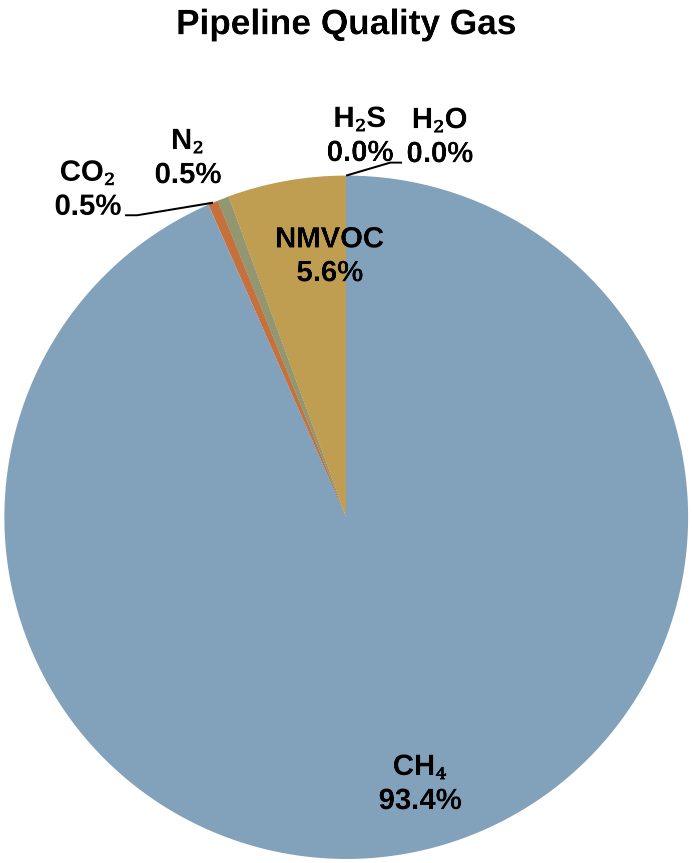
CO_2 = 1
CH_4 = 25
N_2O = 298
SF_6 = 22,800

NETL Life Cycle Model for Natural Gas



Natural Gas Composition by Mass





Carbon content (75%) and energy content (1,027 btu/cf) of pipeline quality gas is very similar to raw production gas (within 99% of both values)

Natural Gas Extraction Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Source							
Contribution to 2009 Natural Gas Mix	Percent	23%	7%	13%	32%	16%	9%
Estimated Ultimate Recovery (EUR), Production Gas	BCF/well	8.6	4.4	67.7	1.2	3.0	0.2
Production Rate (30-yr average)	MCF/day	782	399	6,179	110	274	20
Natural Gas Extraction Well							
Flaring Rate at Extraction Well Location	Percent	51%	51%	51%	15%	15%	51%
Well Completion, Production Gas (prior to flaring)	MCF/completion	47	47	47	4,657	11,643	63
Well Workover, Production Gas (prior to flaring)	MCF/workover	3.1	3.1	3.1	4,657	11,643	63
Well Workover, Number per Well Lifetime	Workovers/well	1.1	1.1	1.1	3.5	3.5	3.5
Liquids Unloading, Production Gas (prior to flaring)	MCF/episode	23.5	n/a	23.5	n/a	n/a	n/a
Liquids Unloading, Number per Well Lifetime	Episodes/well	930	n/a	930	n/a	n/a	n/a
Pneumatic Device Emissions, Fugitive	lb CH_4/MCF	0.05	0.05	0.01	0.05	0.05	0.05
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/MCF	0.003	0.003	0.002	0.003	0.003	0.003
Other Sources of Emissions, Fugitive	lb CH_4/MCF	0.043	0.043	0.010	0.043	0.043	0.043

Natural Gas Processing Plant Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Acid Gas Removal (AGR) and CO_2 Removal Unit							
Flaring Rate for AGR and CO_2 Removal Unit	Percent	100%					
Methane Absorbed into Amine Solution	lb CH_4/MCF	0.04					
Carbon Dioxide Absorbed into Amine Solution	lb CO_2/MCF	0.56					
Hydrogen Sulfide Absorbed into Amine Solution	lb H_2S/MCF	0.21					
NMVOC Absorbed into Amine Solution	lb NMVOC/MCF	6.59					
Glycol Dehydrator Unit							
Flaring Rate for Dehydrator Unit	Percent	100%					
Water Removed by Dehydrator Unit	lb H_2O/MCF	0.045					
Methane Emission Rate for Glycol Pump & Flash Separator	lb CH_4/MCF	0.0003					
Pneumatic Devices & Other Sources of Emissions							
Flaring Rate for Other Sources of Emissions	Percent	100%					
Pneumatic Device Emissions, Fugitive	lb CH_4/MCF	0.05					
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/MCF	0.02					
Other Sources of Emissions, Fugitive	lb CH_4/MCF	0.03					

Natural Gas Processing Plant Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Compression at Gas Plant							
Compressor, Gas-powered Combustion, Reciprocating	Percent	100%	100%		100%	75%	100%
Compressor, Gas-powered Turbine, Centrifugal	Percent			100%			
Compressor, Electrical, Centrifugal	Percent					25%	

Natural Gas Transmission Modeling Properties

Property	Units	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Natural Gas Emissions on Transmission Infrastructure							
Pipeline Transport Distance (national average)	Miles	450					
Transmission Pipeline Infrastructure, Fugitive	lb CH_4/MCF-Mile	0.0003					
Transmission Pipeline Infrastructure, Fugitive (per 450 miles)	lb CH_4/MCF	0.15					
Natural Gas Compression on Transmission Infrastructure							
Distance Between Compressor Stations	Miles	75					
Compression, Gas-powered Reciprocating	Percent	29%					
Compression, Gas-powered Centrifugal	Percent	64%					
Compression, Electrical Centrifugal	Percent	7%					

Uncertainty Analysis Modeling Parameters

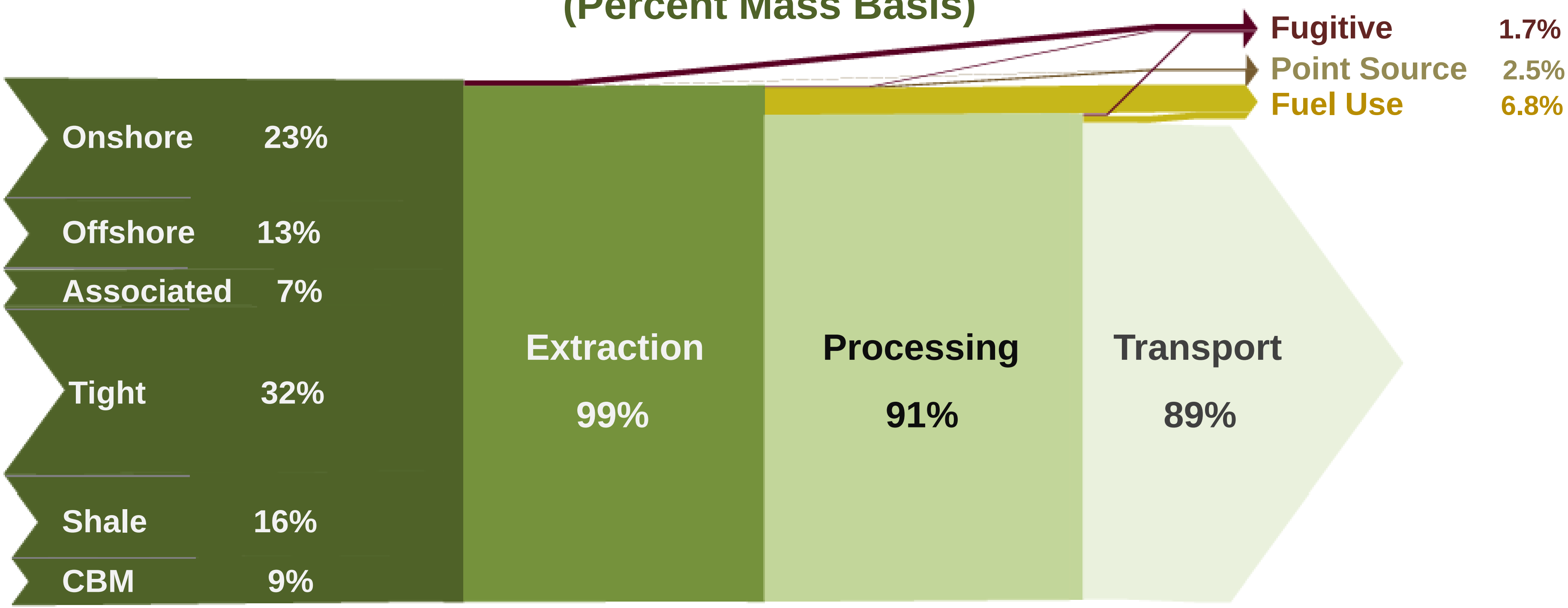
Parameter	Units	Scenario	Onshore Conventional Well	Onshore Associated Well	Offshore Conventional Well	Tight Sands - Vertical Well	Barnett Shale - Horizontal Well	Coal Bed Methane (CBM) Well
Production Rate	MCF/day	Low	403 (-49%)	254 (-36%)	3,140 (-49%)	77 (-30%)	192 (-30%)	14 (-30%)
		Nominal	**782**	**399**	**6,179**	**110**	**274**	**20**
		High	1,545 (+97%)	783 (+96%)	12,284 (+99%)	142 (+30%)	356 (+30%)	26 (+30%)
Flaring Rate at Well	%	Low	41% (-20%)	41% (-20%)	41% (-20%)	12% (-20%)	12% (-20%)	41% (-20%)
		Nominal	**51%**	**51%**	**51%**	**15%**	**15%**	**51%**
		High	61% (+20%)	61% (+20%)	61% (+20%)	18% (+20%)	18% (+20%)	61% (+20%)
Pipeline Distance	miles	Low	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)	360 (-20%)
		Nominal	**450**	**450**	**450**	**450**	**450**	**450**
		High	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)	540 (+20%)

Error bars reported are based on setting each of the three parameters above to the values that generate the lowest and highest result.

Note: “Production Rate” and “Flaring Rate at Well” have an inverse relationship on the effect of the study result. For example to generate the lower bound on the uncertainty range both “Production Rate” and “Flaring Rate Well” were set to “High” and “Pipeline Distance” was set to “Low”.

Accounting for Natural Gas from Extraction thru Delivery to a Large End-User

(Percent Mass Basis)

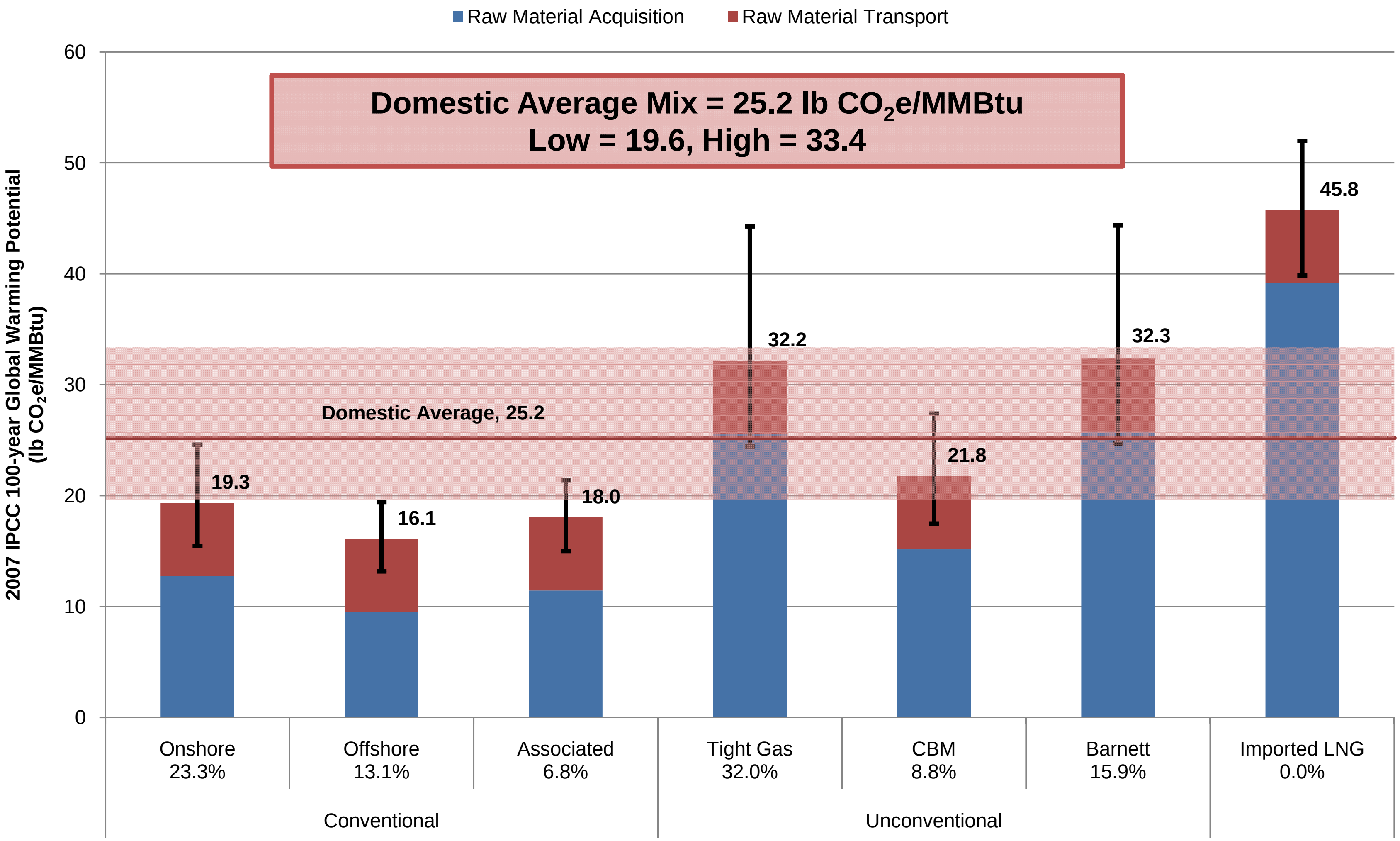


Natural Gas Resource Table	Raw Material Acquisition		Raw Material Transport	Cradle-to-Gate Total:
	Extraction	Processing		
Extracted from Ground	100%	N/A	N/A	100%
Fugitive Losses	1.1%	0.2%	0.4%	1.7%
Point Source Losses (Vented or Flared)	0.1%	2.4%	0.0%	2.5%
Fuel Use	0.0%	5.3%	1.6%	6.8%
Delivered to End User	N/A	N/A	89.0%	89.0%

11% of Natural Gas Extracted from the Earth is Consumed for Fuel Use, Flared, or Emitted to the Atmosphere (point source or fugitive)

Of this, 62% is Used to Power Equipment

Life Cycle GHG Results for Average Natural Gas Extraction and Delivery to a Large End-User

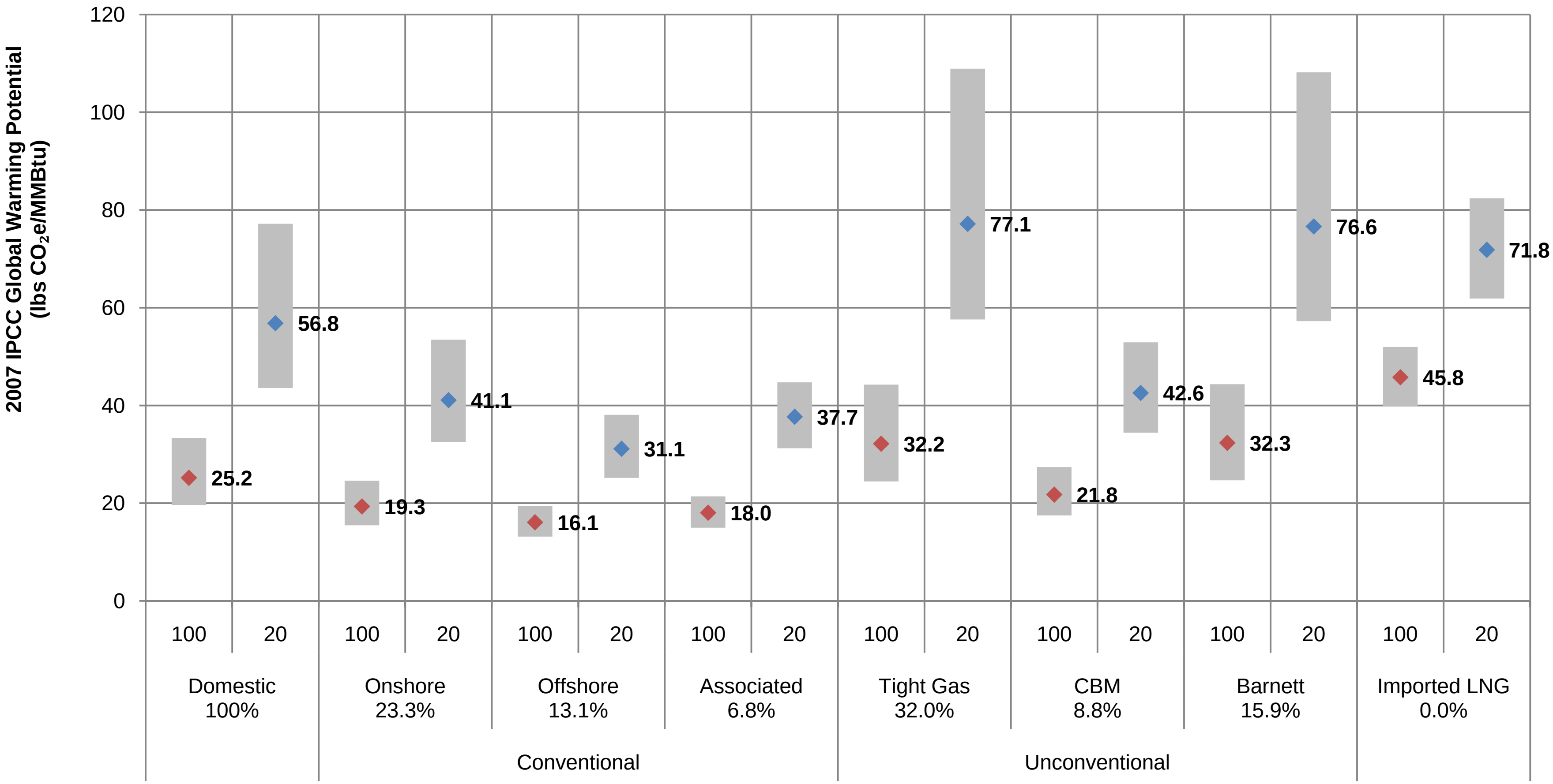


Life Cycle GHG Results for Average Natural Gas Extraction and Delivery to a Large End-User

Comparison of 2007 IPCC GWP Time Horizons:

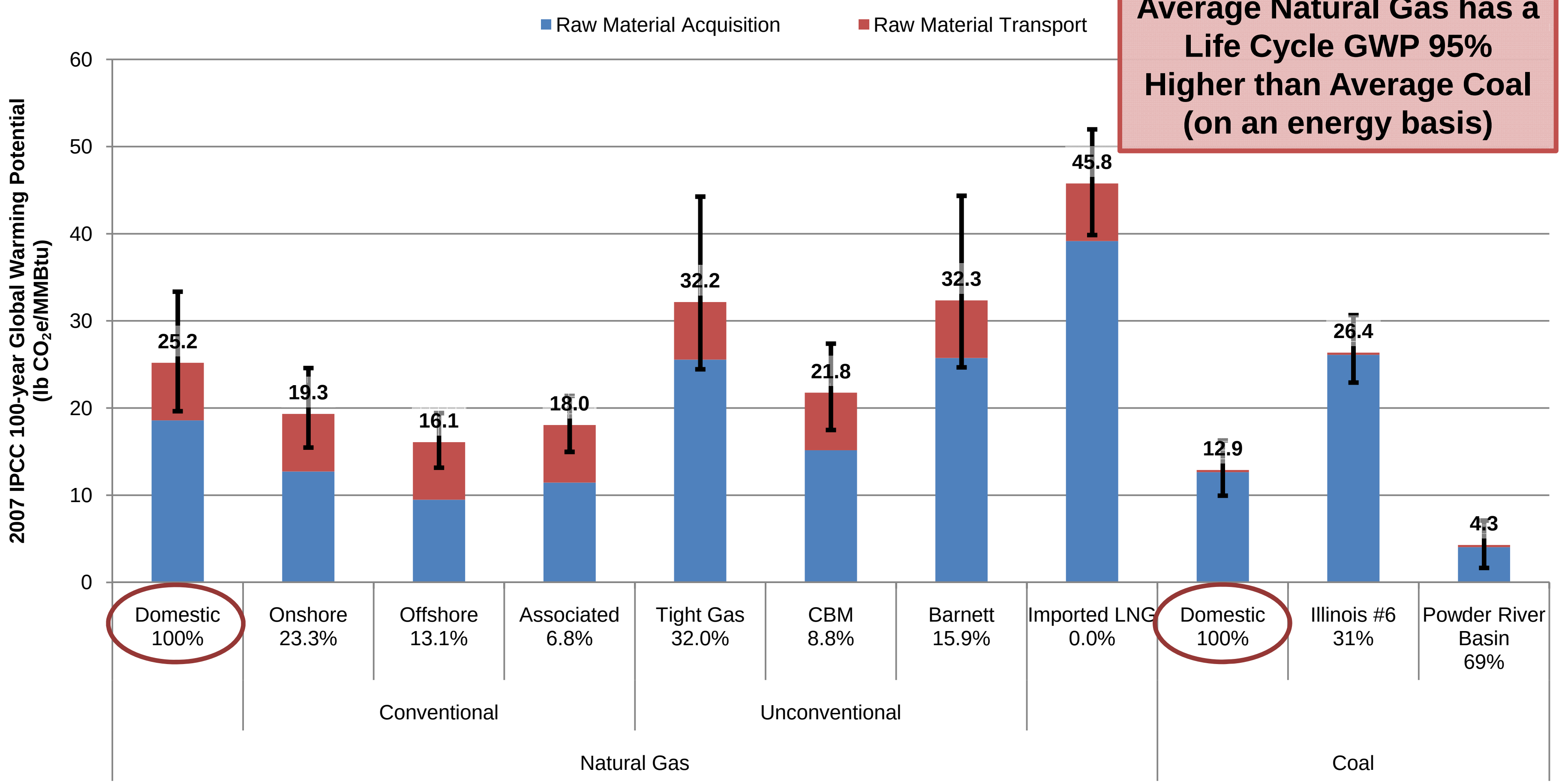
100-year Time Horizon: CO_2 = 1, CH_4 = 25, N_2O = 298

20-year Time Horizon: CO_2 = 1, CH_4 = 72, N_2O = 289



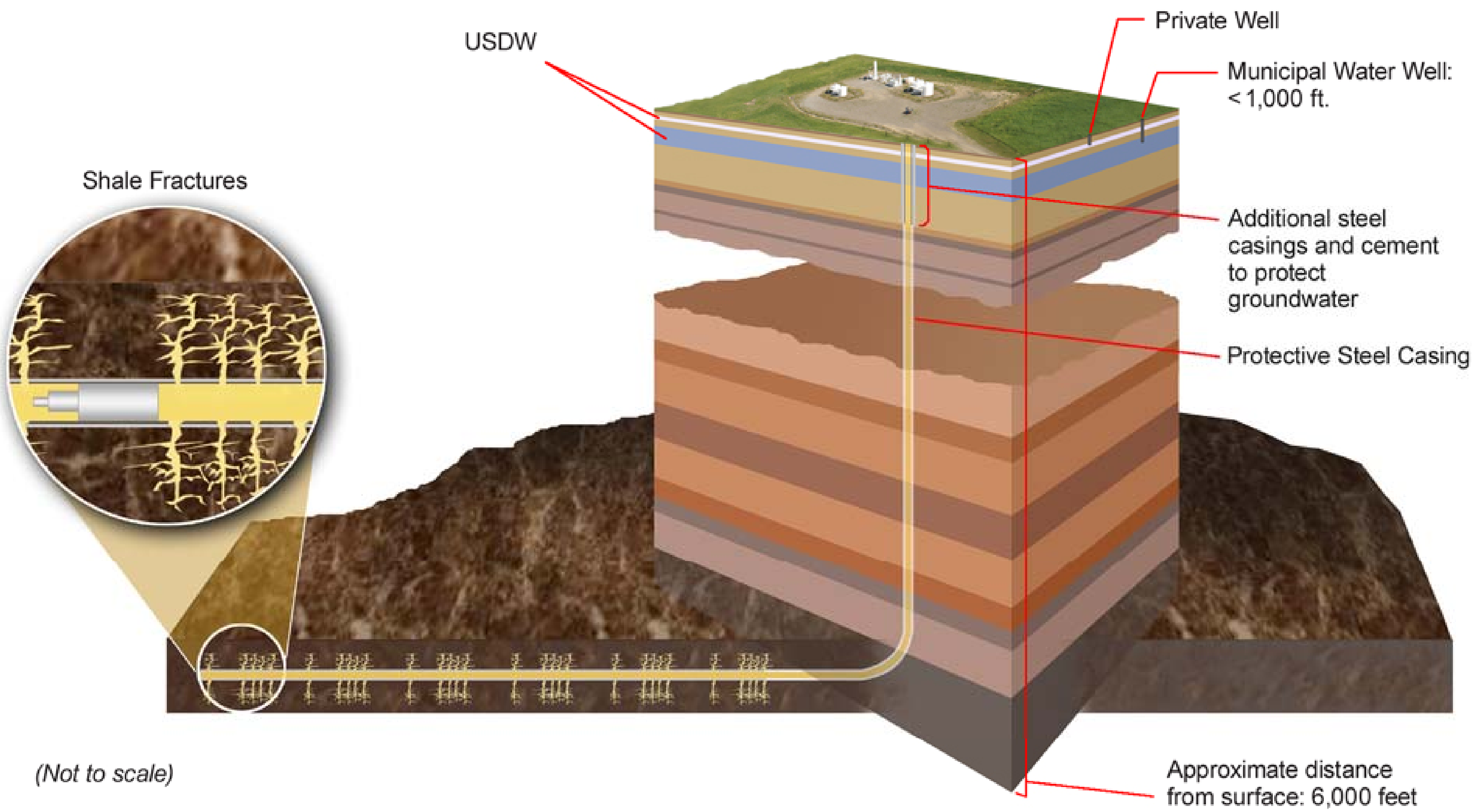
Life Cycle GHG Results for “Average” Natural Gas Extraction and Delivery to a Large End-User

Comparison of Natural Gas and Coal Energy Feedstock GHG Profiles



Average Natural Gas has a Life Cycle GWP 95% Higher than Average Coal (on an energy basis)

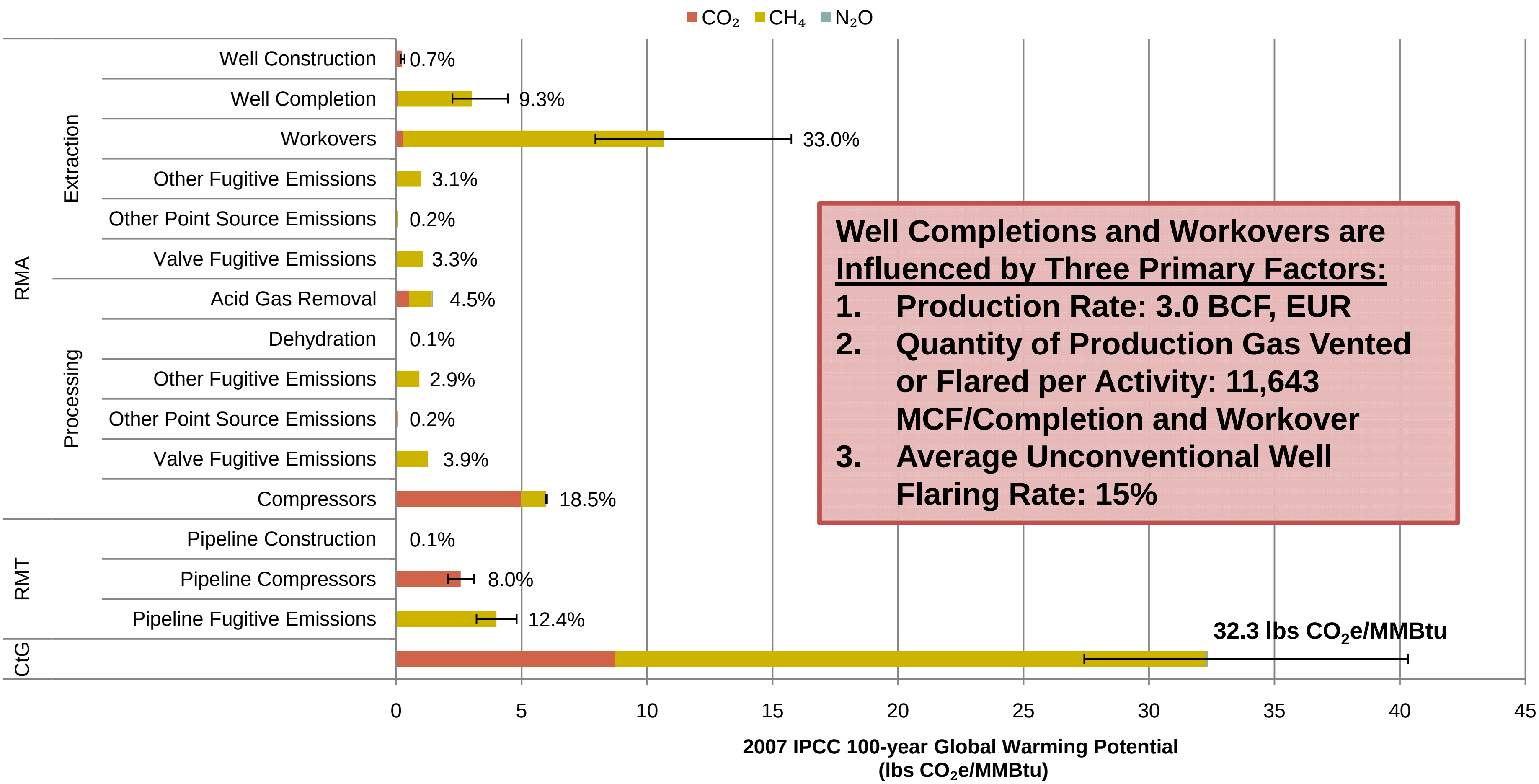
A Deeper Look at Unconventional Natural Gas Extraction via Horizontal Well, Hydraulic Fracturing (*the Barnett Shale Model*)



Source: NETL, *Shale Gas: Applying Technology to Solve America's Energy Challenge*, January 2011

NETL Upstream Natural Gas Profile:
Barnett Shale: Horizontal Well, Hydraulic Fracturing

GWP Result: IPCC 2007, 100-yr (lb CO_2e/MMBtu)

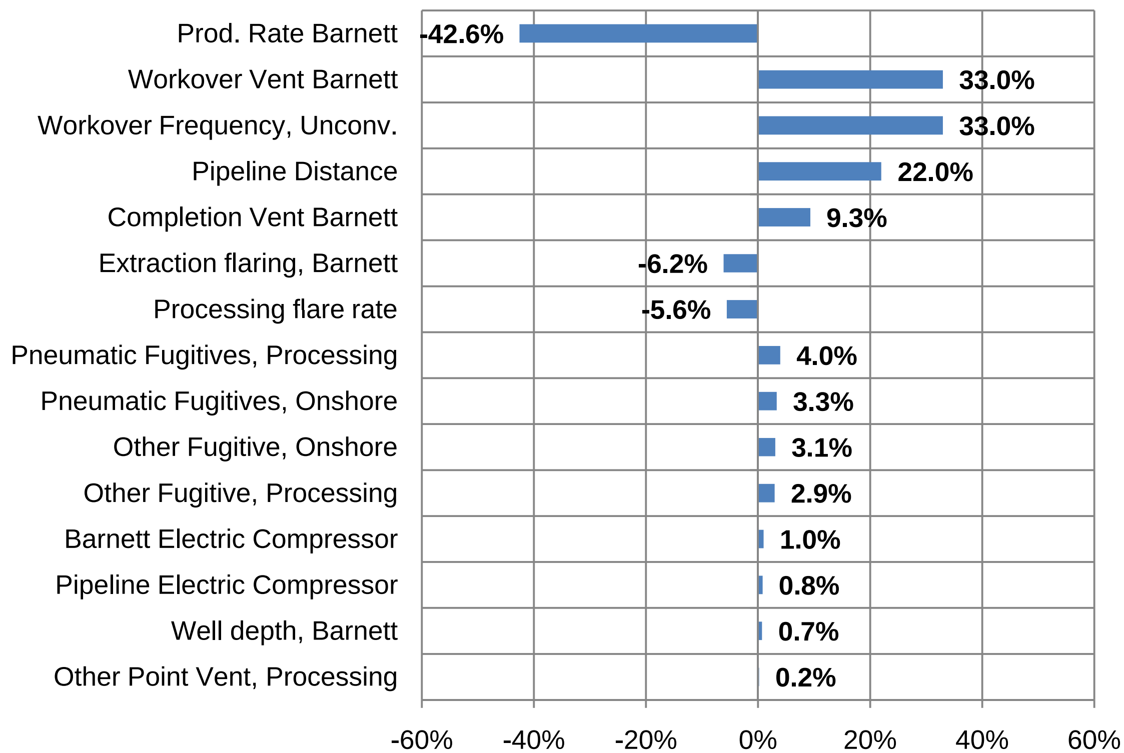


Well Completions and Workovers are
<u>Influenced by Three Primary Factors:</u>

1. **Production Rate: 3.0 BCF, EUR**
2. **Quantity of Production Gas Vented or Flared per Activity: 11,643 MCF/Completion and Workover**
3. **Average Unconventional Well Flaring Rate: 15%**

NETL Upstream Natural Gas Profile:
Barnett Shale: Horizontal Well, Hydraulic Fracturing

Sensitivity Analysis



Default Value	Units
11,508	lb/day
489,023	lb/episode
0.118	episodes/yr
450	miles
489,023	lb/episode
15.0	%
100	%
0.001480	lb fugitives/lb processed gas
0.001210	lb fugitives/lb extracted gas
0.001119	lb fugitives/lb extracted gas
0.001089	lb fugitives/lb processed gas
25	%
7	%
13,000	feet
0.0003940	lb fugitives/lb processed gas

"0%" = 32.3 lb CO_2e/MMBtu Delivered; IPCC 2007, 100-yr Time Horizon

Example: A 1% increase in production rate from 11,508 lb/day to 11,623 lb/day results in a 0.426% decrease in cradle-to-gate GWP, from 32.3 to 32.2 lbs CO_2e/MMBtu

Question #6:

How does natural gas power generation compare to coal-fired power generation on a life cycle GHG basis?

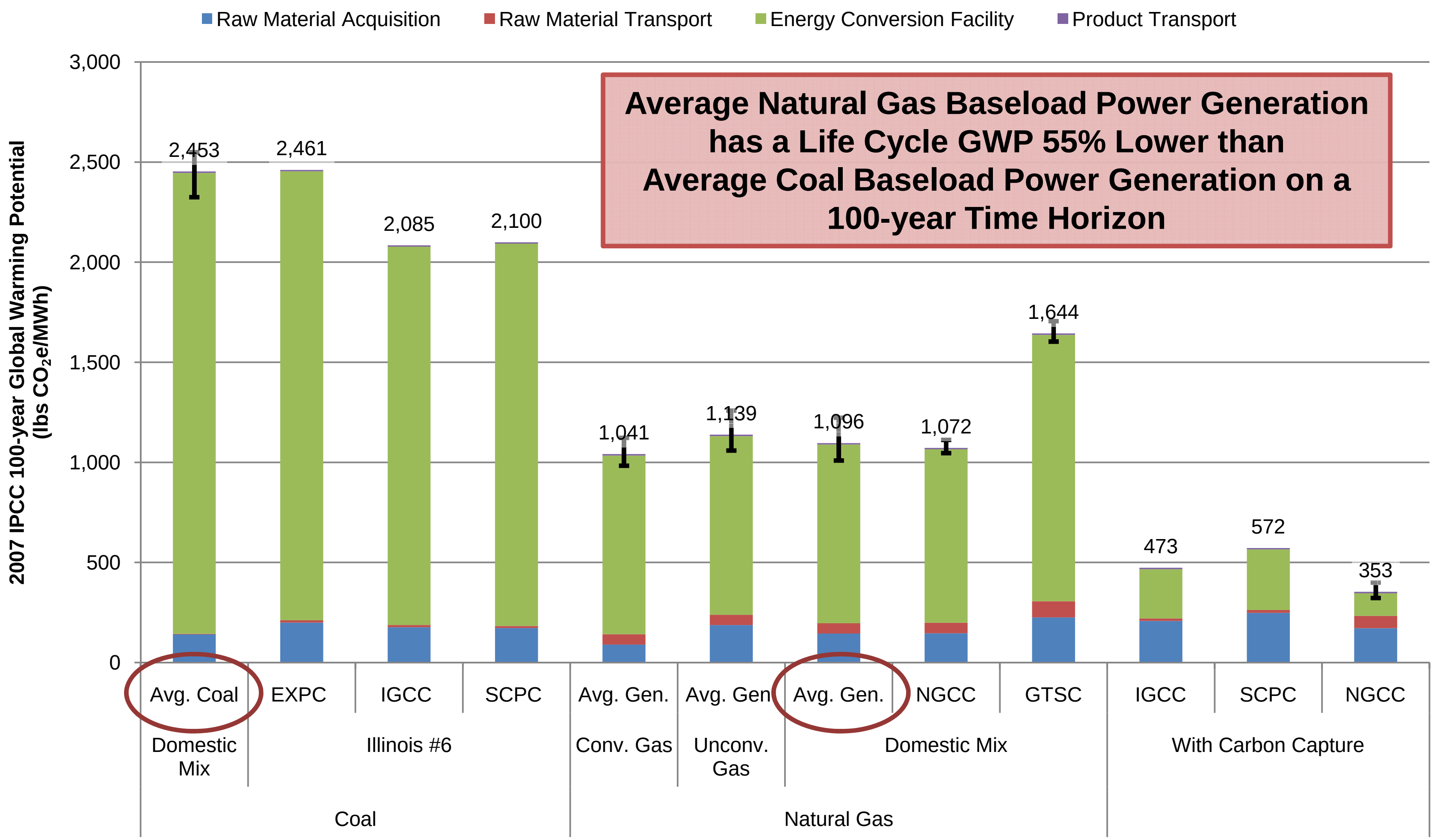
Power Technology Modeling Properties

Plant Type	Plant Type Abbreviation	Fuel Type	Capacity (MW)	Capacity Factor	Net Plant HHV Efficiency
2009 Average Coal Fired Power Plant[a]	Avg. Coal	Domestic Average	Not Calculated	Not Calculated	33.0%
Existing Pulverized Coal Plant	EXPC	Illinois No. 6	434	85%	35.0%
Integrated Gasification Combined Cycle Plant	IGCC	Illinois No. 6	622	80%	39.0%
Super Critical Pulverized Coal Plant	SCPC	Illinois No. 6	550	85%	36.8%
2009 Average Baseload (> 40 MW) Natural Gas Plant[a]	Avg. Gen.	Domestic Average	Not Calculated	Not Calculated	47.1%
Natural Gas Combined Cycle Plant	NGCC	Domestic Average	555	85%	50.2%
Gas Turbine Simple Cycle	GTSC	Domestic Average	360	85%	32.6%
Integrated Gasification Combined Cycle Plant with 90% Carbon Capture	IGCC/CCS	Illinois No. 6	543	80%	32.6%
Super Critical Pulverized Coal Plant with 90% Carbon Capture	SCPC/CCS	Illinois No. 6	550	85%	26.2%
Natural Gas Combined Cycle Plant with 90% Carbon Capture	NGCC/CCS	Domestic Average	474	85%	42.8%

[a] **Net plant higher heating value (HHV) efficiency reported is based on the weighted mean of the 2007 fleet as reported by U.S. EPA, eGrid (2010).**

Comparison of Power Generation Technology Life Cycle GHG Footprints

Raw Material Acquisition thru Delivery to End Customer (lb CO_2e/MWh)



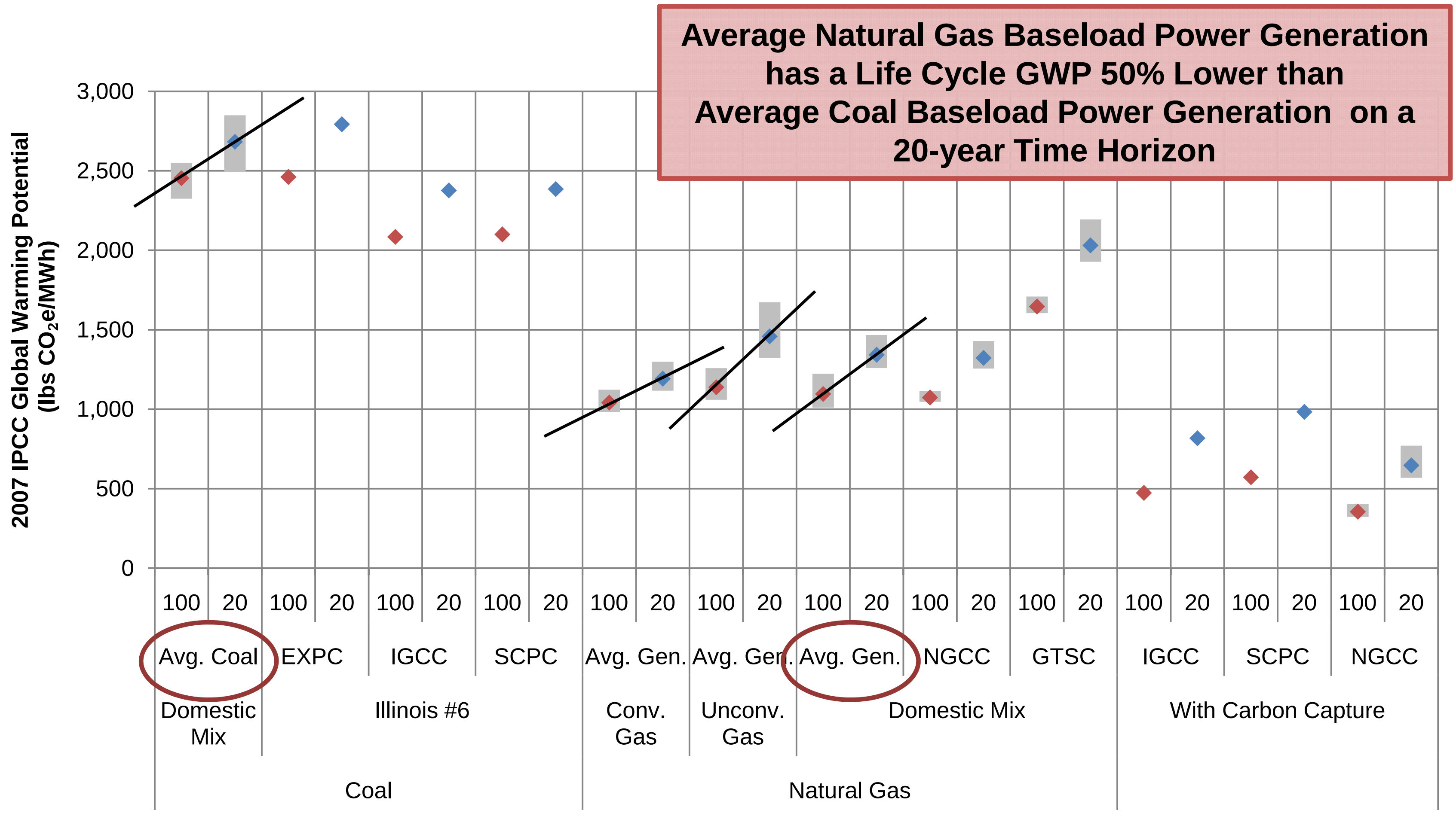
Note: EXPC, IGCC, SCPC, and NGCC (combustion) results, with and without CCS, are based on scenario specific modeling parameters; not industry average data.

Comparison of Power Generation Technology Life Cycle GHG Footprints (lbs CO_2e/MWh)

Comparison of 2007 IPCC GWP Time Horizons:

100-year Time Horizon: $CO_2 = 1$, $CH_4 = 25$, $N_2O = 298$

20-year Time Horizon: $CO_2 = 1$, $CH_4 = 72$, $N_2O = 289$



Note: EXPC, IGCC, SCPC, and NGCC (combustion) results, with and without CCS, are based on scenario specific modeling parameters; not industry average data.

Study Data Limitations

- **Data Uncertainty**
  - Episodic emission factors
  - Formation-specific production rates
  - Flaring rates (extraction and processing)
  - Natural gas pipeline transport distance

- **Data Availability**
  - Formation-specific gas compositions (including CH_4, H_2S, NMVOC, and water)
  - Effectiveness of green completions and workovers
  - Fugitive emissions from around wellheads (between the well casing and the ground)
  - GHG emissions from the production of fracing fluid
  - Direct and indirect GHG emissions from land use from access roads and well pads
  - Gas exploration
  - Treatment of fracing fluid
  - Split between venting and fugitive emissions from pipeline transport

Question #7:

What are the opportunities for reducing GHG emissions?

Technology Opportunities

- **Opportunities for Reducing the GHG Footprint of Natural Gas Extraction and Delivery**
  - Reduce emissions from unconventional gas well completions and workovers
    - Better data is needed to properly characterize this opportunity based on basin type, drilling method, and production rate
  - Improve compressor fuel efficiency
  - Reduce pipeline fugitive emissions thru technology and best management practices (collaborative initiatives)

- **Opportunities for Reducing the GHG Footprint of Natural Gas and Coal-fired Power Generation**
  - Capture the CO_2 at the power plant and sequester it in a saline aquifer or oil bearing reservoir (CO_2-EOR)
  - Improve existing power plant efficiency
  - Invest in advanced power research, development, and demonstration

All Opportunities Need to Be Evaluated on a Sustainable Energy Basis: Environmental Performance, Economic Performance, and Social Performance (e.g., energy reliability and security)

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Recent NETL Life Cycle Assessment Reports

Available at http://www.netl.doe.gov/energy-analyses/:

- Life Cycle Analysis: Existing Pulverized Coal (EXPC) Power Plant
- Life Cycle Analysis: Integrated Gasification Combined Cycle (IGCC) Power Plant
- Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant
- Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant
- Life Cycle Analysis: Power Studies Compilation Report

Analysis complete, report in draft form:

- Life Cycle GHG Analysis of Natural Gas Extraction and Delivery
- Life Cycle Assessment of Wind Power with GTSC Backup
- Life Cycle Assessment of Nuclear Power

Other related Life Cycle Analysis publications available on NETL web-site:

- Life Cycle Analysis: Power Studies Compilation Report (Pres., LCA X Conference)
- An Assessment of Gate-to-Gate Environmental Life Cycle Performance of Water-Alternating-Gas CO_2-Enhanced Oil Recovery in the Permian Basin (Report)
- A Comparative Assessment of CO_2 Sequestration through Enhanced Oil Recovery and Saline Aquifer Sequestration (Presentation, LCA X Conference)

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NETL

Life Cycle Greenhouse Gas Inventory of Natural Gas Extraction, Delivery and Electricity Production

October 24, 2011

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U.S. DEPARTMENT OF ENERGY

Disclaimer

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Final Report

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Acronyms and Abbreviations

AGR	Acid gas removal
API	American Petroleum Institute
bbl	Barrel
Bcf	Billion cubic feet
BOE	Barrel of oil equivalent
Btu	British thermal unit
CBM	Coal bed methane
CCS	Carbon capture and sequestration
cf	Cubic feet
CH_4	Methane
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
DOE	Department of Energy
eGRID	Emissions & Generation Resource Integrated Database
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
EUR	Estimated ultimate recovery
EXPC	Existing pulverized coal
g	Gram
gal	Gallon
Gg	Gigagram
GHG	Greenhouse gas
GTSC	Gas turbine simple cycle
GWP	Global warming potential
H_2S	Hydrogen sulfide
hp-hr	Horsepower-hour
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
km	Kilometer
kWh	Kilowatt-hour
lb, lbs	Pound, pounds
LCA	Life cycle assessment, analysis
LNG	Liquefied natural gas
m	Meter
m^3	Meters cubed
Mbbl	Thousand barrels
Mcf	Thousand cubic feet
MJ	Megajoule
MMbbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
MW	Megawatt
MWh	Megawatt-hour
N_2O	Nitrous oxide
NETL	National Energy Technology Laboratory
NG	Natural gas
NGCC	Natural gas combined cycle
NMVOC	Non-methane volatile organic compound
NREL	National Renewable Energy Laboratory
PRB	Powder River Basin
psig	Pounds per square inch gauge
PT	Product transport
RMA	Raw material acquisition
RMT	Raw material transport
SCPC	Super critical pulverized coal
T&D	Transmission and distribution
Tcf	Trillion cubic feet
ton	Short ton (2,000 lb)
tonne	Metric ton (1,000 kg)
UP	Unit process

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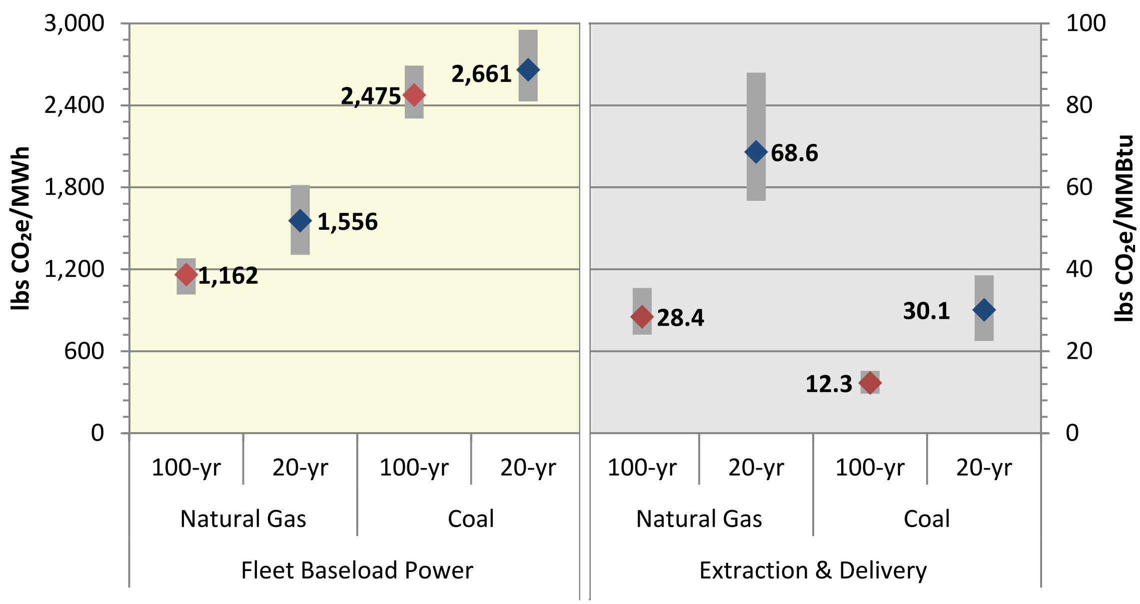
Executive Summary

Natural gas-fired baseload power production has life cycle greenhouse gas emissions 42 to 53 percent lower than those for coal-fired baseload electricity, after accounting for a wide range of variability and compared across different assumptions of climate impact timing. The lower emissions for natural gas are primarily due to differences in the current fleets' average efficiency – 53 percent for natural gas versus 35 percent for coal, and a higher carbon content per unit of energy for coal than natural gas. Even using unconventional natural gas, from tight sands, shale and coal beds, and compared with a 20-year global warming potential (GWP), natural gas-fired electricity has 39 percent lower greenhouse gas emissions than coal per delivered megawatt-hour (MWh) using current technology.

In a life cycle analysis (LCA), comparisons must be based on providing an equivalent service or function, which in this study is the delivery of 1 MWh of electricity to an end user. This life cycle greenhouse gas inventory also developed upstream (from extraction to delivery to a power plant) emissions for delivered energy feedstocks, including six different domestic sources of natural gas, of which three are unconventional gas, and two types of coal, and then combines them both into domestic mixes. These are important characterizations for the LCA community, and can be used as inputs into a variety of processes. However, these upstream, or cradle-to-gate, results are not appropriate to compare when making energy policy decisions, since the two uncombusted fuels do not provide an equivalent function. These results highlight the importance of specifying an end-use basis—not necessarily power production—when comparing different fuels.

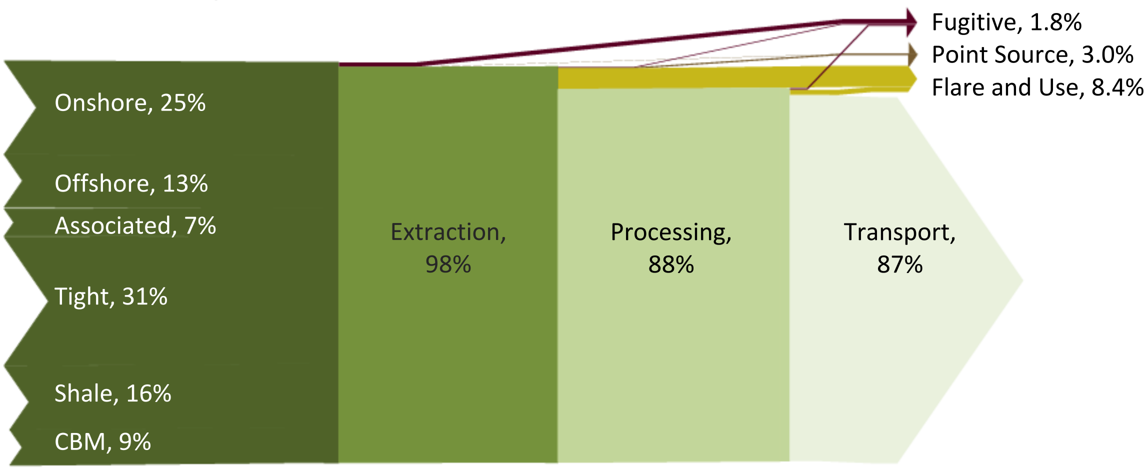
Figure ES-1: Natural Gas and Coal GHG Emissions Comparison



Despite the conclusion that natural gas has lower greenhouse gases than coal on a delivered power basis, the extraction and delivery of the gas has a large climate impact —32 percent of U.S. methane emissions and 3 percent of U.S. greenhouse gases (EPA, 2011b). As **Figure ES-2** shows, there are significant emissions and use of natural gas—13 percent at the city or plant gate—even without considering final distribution to small end-users. The vast majority of the reduction in extracted natural gas —64 percent cradle-to-gate—are not emitted to the atmosphere, but can be attributed to the use of the natural gas as fuel for extraction and transport processes such as compressor operations. Increasing compressor efficiency would lower both the rate of use and the CO_2 emissions associated with the combustion of the gas for energy. Note that this figure accounts for the total mass of natural gas extracted from the earth, including water, acid gases, and other non-methane content.

But, with methane making up 75 to 95 percent of the natural gas flow, there are many opportunities for reducing the climate impact associated with direct venting to the atmosphere. A further 24 percent of the natural gas losses can be characterized as point source, and have the potential to be flared—essentially a conversion of GWP-potent methane to carbon dioxide.

Figure ES-2: Cradle-to-Gate Reduction in Delivered Natural Gas for 2009



The conclusions drawn from this analysis are robust to a wide array of assumptions. However, as with any inventory, they are dependent on the underlying data, and there are many opportunities to enhance the information currently being collected. This analysis shows that the results are both sensitive to and impacted by the uncertainty of a few key parameters: use and emission of natural gas along the pipeline transmission network; the rate of natural gas emitted during unconventional gas extraction processes such as well completion and workovers; and the lifetime production of wells, which determine the denominator over which lifetime emissions are placed.

Table ES-1: Average and Marginal Upstream Greenhouse Gas Emissions (lbs CO_2e/MMBtu)

Source		Average	Marginal	Percent Change
Conventional	Onshore	34.2	20.1	-41.2%
	Offshore	14.3	14.1	-1.4%
	Associated	18.5	18.4	-0.8%
Unconventional	Tight	32.4	32.4	0.0%
	Shale	32.5	32.5	0.0%
	Coal Bed Methane	19.1	19.3	1.4%
Liquefied Natural Gas		42.8	42.5	-0.6%

This analysis inventoried both average and marginal production rates for each natural gas type, with results shown in **Table ES-1**. The average represents natural gas produced from all wells, including older and low productivity stripper wells. The marginal production rate represents natural gas from newer, higher productivity wells. The largest difference was for onshore conventional natural gas, which had a 41 percent reduction in upstream greenhouse gas emissions from 20.1 to 34.2 lbs CO_2e/MMBtu when going from marginal to average production rates. This change has little impact on emissions from power production.

This inventory and analysis are for greenhouse gases only, and there are many other factors that must be considered when comparing energy options. A full inventory of conventional and toxic air emissions, water use and quality, and land use is currently under development, and will allow comparison of these fuels across multiple environmental categories. Further, all options need to be evaluated on a sustainable energy basis, considering full environmental performance, as well as economic and social performance, such as the ability to maintain energy reliability and security. There are many opportunities for decreasing the greenhouse gas emissions from natural gas and coal extraction, delivery and power production, including reducing fugitive methane emissions at wells and mines, and implementing advanced combustion technologies and carbon capture and storage.

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1 Introduction

Natural gas is seen as a cleaner burning and flexible alternative to other fossil fuels, and is used in residential, commercial, industrial, and transportation applications in addition to an expanding role in power production. However, the primary component of natural gas by mass is methane, which is also a powerful greenhouse gas—8 to 72 times as potent as carbon dioxide (Forster et al., 2007). Losses of this methane to the atmosphere during the extraction, transmission, and delivery of natural gas to end users made up 32 percent of U.S. 2009 total methane emissions, and 3 percent of all greenhouse gases (EPA, 2011b). The rate of loss, and the associated emissions, varies with the source of natural gas—both the geographic location of the formation, as well as the technology used to extract the gas.

This report expands upon previous life cycle assessments (LCA) performed by the National Energy Technology Laboratory (NETL) of natural gas power generation technologies by describing in detail the greenhouse gas emissions due to extracting, processing and transporting various sources of natural gas to large end users, and the combustion of that natural gas to produce electricity. Emissions inventories are created for the 2009 average natural gas production, but also for natural gas produced from the next highly-productive well for each source of natural gas. This context allows analysis of what the emissions are, and also what they could be in the future.

This analysis also includes an expanded system which compares the life cycle greenhouse gases (GHGs) from baseload natural gas-fired power plants with the GHGs generated by coal-fired plants, including extraction and transportation of the respective fuels. This comparison provides perspective on the scale of fuel extraction and delivery emissions relative to subsequent emissions from power generation and electricity transmission.

Beyond presenting the inventory, the goal of this report is to provide a clear presentation of NETL's natural gas model, including documentation of key assumptions, data sources, and model sensitivities. Further, areas of large uncertainty in the inventory are highlighted, along with areas for potential improvement for both data collection and greenhouse gas reductions.

This greenhouse gas inventory and analysis are part of a larger comprehensive life cycle assessment being performed on the same natural gas system. That assessment effort includes new sources of shale gas and expands the inventory beyond greenhouse gases to include criteria and hazardous air pollutants, water use and quality, direct and indirect land use and greenhouse gases from land use change.

2 Inventory Method, Assumptions, and Data

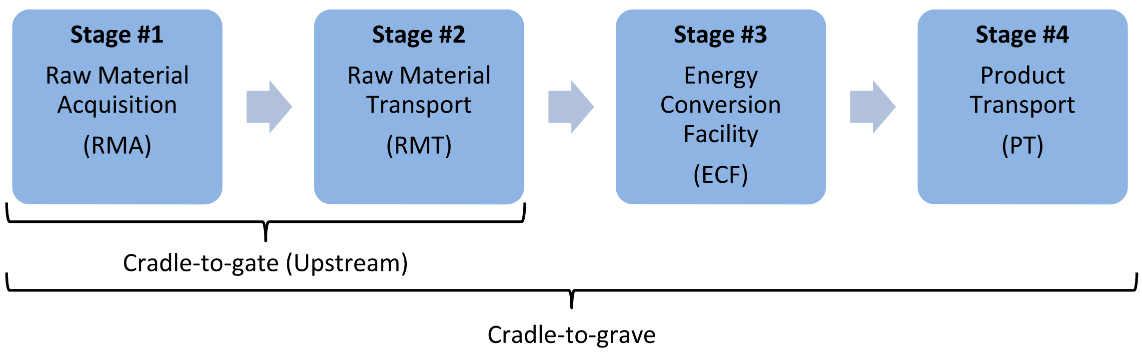
This ISO 14040-compliant inventory and analysis applies the LCA framework to determine the greenhouse gas burdens of natural gas extraction, transport and use in the U.S. The boundaries, basis of comparison, model structure, and data used by this analysis are discussed below. Further detail is available in the Appendix to this document.

2.1 Boundaries

The first piece of this analysis is a cradle-to-gate greenhouse gas inventory that focuses on raw material acquisition and transport; as such, it is also referred to as an upstream inventory, upstream being a relative term (relative, in this case, to the power plant). As shown in **Figure 2-1**, and in more detail in **Figure 2-2**, the boundary of Stage #1 includes all construction and operation activities necessary to extract fuel from the earth, and ends when fuel is extracted, prepared, and ready for final transport to the power plant. Stage #2 includes all construction and operation activities necessary to move fuel from the extraction and processing point to the power plant, and ends at the power plant gate. The boundary of the upstream inventory of natural gas does not include the distribution system of natural gas to small end users, but rather is representative of delivery to a large end user such as a power plant or even a city gate.

The second piece of this analysis is a cradle-to-grave context to compare the greenhouse gas emissions of natural gas extraction and transport with those of electricity production and transmission. Neither piece of analysis includes the use of the produced product, but rather ends when the product is delivered. Coal-fired power systems are used as a further point of comparison.

Figure 2-1: Life Cycle Stages and Boundary Definitions



2.2 Basis of Comparison (Functional Unit)

To establish a basis for comparison, the LCA method requires specification of a functional unit, the goal of which is to define an equivalent service provided by the systems of interest. Within the cradle-to-gate boundary of this analysis, the functional unit is 1 MMBtu of fuel delivered to the gate of an energy conversion facility or other large end user. When the boundaries of the analysis are expanded to include power production, the functional unit is the delivery of 1 MWh of electricity to the consumer. In both contexts, the period over which the service is provided is 30 years.

2.2.1 Global Warming Potential

Greenhouse gases in this inventory are reported on a common mass basis of carbon dioxide equivalents (CO_2e) using the global warming potentials (GWP) of each gas from the 2007 Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (Forster, et al., 2007). The default GWP used is the 100-year time frame, but in some cases, results for the 20-year time frame are presented as well. Selected results comparing all three time frames are included in the Appendix. **Table 2-1** shows the GWPs used for the greenhouse gases inventoried in this study.

Table 2-1: IPCC Global Warming Potentials (Forster, et al., 2007)

GHG	20-year	100-year (Default)	500-year
CO_2	1	1	1
CH_4	72	25	7.6
N_2O	289	298	153
SF_6	16,300	22,800	32,600

2.3 Representativeness of Inventory Results

This inventory uses data gathered from a variety of sources, each of which represents a particular temporal period, geographic location, and state of technology. Since the results of this study are the combination of each of those sources, this section discusses what the results of this study represent in each of those categories.

2.3.1 Temporal

The natural gas upstream inventory results best represent the year 2009, because of the use of the 2009 EIA natural gas production data to create the mix of natural gas sources in the domestic average result and well production rates for each source of natural gas. The year-over-year change to that mix of natural gas sources is small, and the results could represent a period from 2004 to 2012.

This study does not attempt to forecast technological advances or market shifts that might significantly change production rates or emissions of less mature formations.

The inventory results through the conversion of fuel to electricity represent the year 2010 for NETL system study-based technologies and the year 2007 for the fleet average values for coal and natural gas, since this is the vintage of the latest eGRID data release (EPA, 2010). Again, there would be little year-over-year change to the information, and so this LCA could reasonably represent a longer time period, from 2004 to 2015.

Some information included in this inventory pre-dates the temporal period stated above, but was determined to be the latest or highest quality available data.

The time frame of this study is 30 years, but that does not accurately represent a well drilled 30 years from now and operating 60 years into the future. An assumption is made about resource availability based on current estimated ultimate recovery values, and forecasts from the Energy Information Administration (EIA).

2.3.2 Geographic

The results of this inventory are representative of the lower 48 United States. Natural gas from Alaska is neither explicitly included nor excluded, nor are imports and exports. In some situations, source data may not break out information about geographic location, and so is implicitly included in this inventory. However, the error associated with this type of inclusion—or exclusion—is small.

2.3.3 Technological

The natural gas upstream inventory results include two distinct technological representations. The first is a baseline result which represents average 2009 natural gas production, including production from older, less productive wells. Production data from that year is used to create an average domestic mix of natural gas sources, and the production rate of each source well is generally based on 2009 well count and production data. The second set of results is representative of a new marginal unit of natural gas produced in 2009; these results use a variety of methods to create production rates for wells which would create the next unit of natural gas.

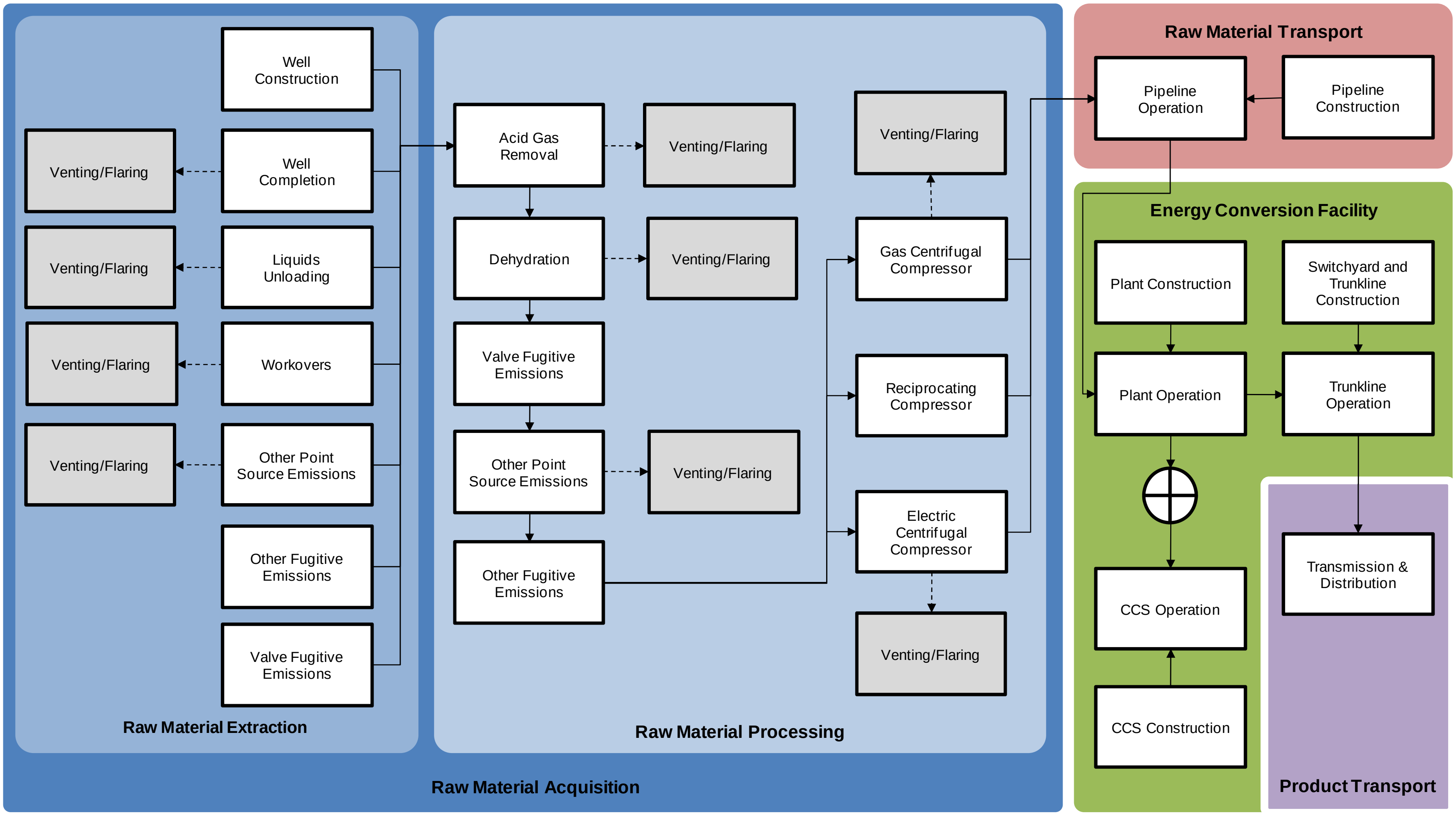
The results of this inventory are representative of currently installed technology as of 2011. This installed base is different from current technology because it includes much older equipment that is still operating.

2.4 Model Structure

All results for this inventory were calculated by NETL's LCA model for natural gas power systems. This model is an interconnected network of operation and construction blocks. Each block in the model, referred to as a unit process, accounts for the key inputs and outputs of an activity. The inputs of a unit process include the purchased fuels, resources from nature (fossil feedstocks, biomass, or water), and man-made raw materials. The outputs of a unit process include air emissions, water effluents, solid waste, and product(s). The role of an LCA model is to converge on the values for all intermediate flows within the interconnected network of unit processes and then scale the flows of all unit processes to a common basis, or functional unit.

The network of unit processes used for the modeling of natural gas power is shown in **Figure 2-2**. Note that only the RMA and RMT portions of the model are necessary to determine the upstream environmental burdens of natural gas; a broader scope—from raw material acquisition through delivery of electricity—is necessary to determine the cradle-to-grave environmental burdens of natural gas power. For simplicity, the following figure shows the extraction and delivery for a generic natural gas scenario; NETL's actual model uses six parallel modules to arrive at the life cycle results for a mix of six types of natural gas. This figure also shows a breakdown of the RMA stage into extraction and processing sub-stages.

Figure 2-2: Natural Gas LCA Modeling Structure



2.5 Data

The primary unit processes of this model are based on data compiled by NETL. Secondary unit processes, such as production of construction materials besides steel, are based on third party data. A full description of data sources is available in the Appendix.

Where data for the inventory is available, high and low values are collected, along with a nominal value. When results are presented, three cases are shown: a nominal case, a high case and a low case. The high and low results (error bars on the results) are a deterministic representation of the variability on the data and not indicative of an underlying distribution or likelihood.

2.5.1 Sources of Natural Gas

This inventory and analysis includes results for natural gas domestically extracted from six sources in the lower 48 states:

1. Conventional onshore
2. Associated
3. Conventional offshore
4. Tight sands
5. Shale formations (Barnett)
6. Coal bed methane

This is not a comprehensive list of natural gas extracted or consumed in the United States. Natural gas extracted in Alaska, 2 percent of domestically extracted natural gas, is included as conventional onshore production. The Haynesville shale play makes up a large portion of unconventional shale production, but it is assumed here that the Barnett play is representative of all shale production. Imported natural gas (18 percent of 2009 total consumption, 88 percent of which is imported via pipeline from Canada) is not included. About 12 percent of imports in 2009 were brought in as liquefied natural gas (LNG) from a variety of countries of origin. While this inventory includes a profile for LNG from offshore extraction in Trinidad and Tobago, this natural gas is not included in the domestic production mix.

Table 2-2 shows the makeup of the domestic production mix in the United States in 2009 and the mix of conventional and unconventional extraction. Note that in 2009 unconventional natural gas sources make up 56 percent of production and the majority of consumption in the Unites States (EIA, 2011a).

Table 2-2: Mix of U.S. Natural Gas Sources (EIA, 2011a)

Source	Conventional			Unconventional		
	Onshore	Associated	Offshore	Tight	Shale	CBM
Domestic Mix	25%	13%	7%	31%	16%	9%
Type Mix	44%			56%		
	56%	15%	29%	56%	28%	15%

The characteristics of these six sources of natural gas are summarized next, including a description of the extraction technologies.

2.5.1.1 Onshore

Conventional onshore natural gas is recovered by vertical drilling techniques. Once a conventional onshore natural gas well has been discovered, the natural gas reservoir does not require significant preparation or stimulation for natural gas recovery. Compressors are used to move natural gas through all process equipment and pressurize it for pipeline transport. Approximately 25 percent (5.2 TCF) of U.S. natural gas production is from conventional onshore gas wells (EIA, 2011a).

An intermittent procedure called liquids unloading is performed at mature onshore conventional natural gas wells to remove water and other liquids from the wellbore; if these liquids are not removed, the flow of natural gas is impeded. Another intermittent activity is a well workover, which is necessary to repair damage to the wellbore and replace downhole equipment, if necessary.

Natural gas is lost through intentional venting, which may be necessary for safety reasons, during well completion when natural gas recovery equipment or gathering lines have not yet been installed, or when key process equipment is offline for maintenance. When feasible, vented natural gas can be recovered and flared, which reduces the global warming potential of the vented natural gas by converting methane to carbon dioxide. Losses of natural gas also result from fugitive emissions due to the opening and closing of valves, and processes where it is not feasible to use vapor recovery equipment.

2.5.1.2 Offshore

Conventional offshore natural gas is recovered by vertical drilling techniques, similar to onshore. Once a conventional offshore natural gas well has been discovered, the natural gas reservoir does not require significant preparation or stimulation for natural gas recovery. A natural gas reservoir must be large in order to justify the capital outlay for the completion of the well and construction of an offshore drilling platform, so production rates tend to be very high. Approximately 13 percent (2.7 TCF) of the United States natural gas supply in 2009 was from the conventional extraction from offshore natural gas wells (EIA, 2011a).

2.5.1.3 Associated

Associated natural gas is co-extracted with crude oil. The extraction of onshore associated natural gas is similar to the extraction methods for conventional onshore natural gas (discussed above). Similar to conventional onshore and offshore natural gas wells, associated natural gas extraction includes losses due to well completion, workovers, and fugitive emissions. Since the natural gas is co-produced with petroleum, the use of oil/gas separators is necessary to recover natural gas from the mixed product stream. Another difference between associated natural gas and other conventional natural gas sources is that liquid unloading is not necessary for associated natural gas wells because the flow of petroleum prevents the accumulation of liquids in the well. Approximately 7 percent (1.4 TCF) of U.S. natural gas production is from conventional onshore oil wells (EIA, 2011a). The majority of these wells are in Texas and Louisiana (EIA, 2010).

2.5.1.4 Tight Gas

The largest single source of domestically produced natural gas, and the largest share of unconventional natural gas, is tight gas. From naturalgas.org, tight gas is defined as follows:

> …trapped in unusually impermeable, hard rock, or in a sandstone or limestone formation that is unusually impermeable and non-porous (tight sand). In a conventional natural gas deposit, once drilled, the gas can usually be extracted quite readily, and easily. A great deal more effort has to be put into extracting gas from a tight formation. Several techniques exist that allow natural gas to be extracted, including fracturing and acidizing. However, these techniques are also very costly. Like all unconventional natural gas, the economic incentive must be there to incite

companies to extract this costly gas instead of more easily obtainable, conventional natural gas (NGSA, 2010).

Approximately 31 percent (6.6 TCF) of natural gas produced domestically is from tight deposits. This analysis assumes tight gas wells are vertically drilled and hydraulically fractured.

2.5.1.5 Shale

Natural gas is also dispersed throughout shale formations, such as the Barnett Shale region in northern Texas. Shale gas cannot be recovered using conventional extraction technologies, but is recovered through the use of horizontal drilling and hydraulic fracturing (hydrofracking). Horizontal drilling creates a wellbore that runs the length of a shale formation, and hydrofracking uses high pressure fluid (a mixture of water, surfactants, and proppants) for breaking apart the shale formation and facilitating the flow of natural gas. Hydrofracking is performed during the original completion of a shale gas well, but due to the steeply declining production curves of shale gas wells, hydrofracking is also performed during the workover of shale gas wells. Unlike conventional natural gas wells, shale gas wells do not require liquid unloading because wellbore liquids are reduced during workover operations. Natural gas from shale formations accounts for approximately 16 percent (3.3 TCF) of the U.S. natural gas production (EIA, 2011a).

2.5.1.6 Coal Bed Methane

Natural gas can be recovered from coal seams through the use of shallow horizontal drilling. The development of a well for coal bed methane requires horizontal drilling followed by a depressurization period during which naturally-occurring water is discharged from the coal seam. Coal bed methane (CBM) wells do not require liquid unloading and the emissions from CBM workovers are similar to those for shale gas wells. The production of natural gas from CBM wells accounts for approximately 9 percent (1.8 TCF) of the U.S. natural gas production (EIA, 2011a).

2.5.2 Natural Gas Composition

Relevant to all phases of the life cycle, the composition of natural gas varies considerably depending on source, and even within a source. For simplicity, a single assumption regarding natural gas composition is used, although that composition is modified as the natural gas is prepared for the pipeline (EPA, 2011a). **Table 2-3** shows the composition on a mass basis of production and pipeline quality natural gas. The pipeline quality natural gas has had water and acid gases (CO_2 and H_2S) removed, and non-methane VOCs either flared or separated for sale. The pipeline quality natural gas has higher methane content per unit mass. The energy content does not change significantly.

Table 2-3: Natural Gas Composition on a Mass Basis

Component	Production	Pipeline Quality
CH_4 (Methane)	78.3%	92.8%
NMVOC (Non-methane VOCs)	17.8%	5.54%
N_2 (Nitrogen)	1.77%	0.55%
CO_2 (Carbon dioxide)	1.51%	0.47%
H_2S (Hydrogen Sulfide)	0.50%	0.01%
H_2O (Water)	0.12%	0.01%

2.5.3 Data for Natural Gas Extraction

This analysis models the extraction of natural gas by characterizing key construction and operation activities at the natural gas wellhead. A summary of each unit process of NETL's model of natural gas extraction is provided below. **Appendix A** includes comprehensive documentation of the data sources and calculations for these unit processes.

2.5.3.1 Well Construction

Data for the construction and installation of natural gas wellheads are based on the energy requirements and linear drill speed of diesel-powered drilling rigs, the depths of wells, and the casing materials required for a wellbore. Construction and installation are one-time activities that are apportioned to each unit of natural gas operations by dividing all construction and installation emissions by the lifetime in years and production in million cubic feet of a typical well.

2.5.3.2 Well Completion

The data for well completion describe the emission of natural gas that occurs during the development of a well, before natural gas recovery and other equipment have been installed at the wellhead. Well completion is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from an event that occurs one time in the life of a well.

The methane emissions from the completion of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells produce 36.65 Mcf/completion and unconventional wells produce 9,175 Mcf/completion (EPA, 2011a).

Within the unconventional well category, NETL adjusted EPA's completion emission factors to account for the different reservoir pressures of unconventional wells. NETL used EPA's emission factor of 9,175 Mcf of methane per completion for Barnett Shale gas wells. NETL adjusted this emission factor downward for tight gas in order to account for the lower reservoir pressures of tight gas wells. The pressure of a well (and, in turn, the volume of natural gas released during completion) is associated with the production rate of a well and therefore was used to scale the methane emission factor. The production rate of tight gas wells is 40 percent of that for Barnett Shale wells (with EURs of 1.2 BCF for tight gas vs. 3.0 BCF for Barnett Shale), and thus NETL assumes that the completion emission factor for tight gas wells is 3,670 Mcf of methane per completion (40 percent × 9,175 = 3,670).

CBM wells also involve unconventional extraction technologies, but have lower reservoir pressures than shale gas or tight gas wells. The corresponding emission factor of CBM wells is 49.57 Mcf of methane per completion, which is the well completion factor that EPA reports for low pressure wells (EPA, 2011a).

The analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. For instance, when factoring for the density of natural gas, a conventional completion emission of 36.65 Mcf is equivalent to 1,540 lbs. CH_4/completion.

2.5.3.3 Liquid Unloading

The data for liquids unloading describe the emission of natural gas that occurs when water and other condensates are removed from a well. These liquids impede the flow of natural gas from the well, and thus producers must occasionally remove the liquids from the wellbore. Liquid unloading is necessary for conventional gas wells—it is not necessary for unconventional wells or associated gas wells. Liquid unloading is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from the occasional maintenance of a well.

The methane emissions from liquids unloading are based on the total unloading emissions from conventional wells in 2007, the number of active conventional wells in 2007, and the average frequency of liquids unloading (EPA, 2011a). The resulting emission factor for liquids unloading is 776 lb CH_4/episode.

2.5.3.4 Workovers

Well workovers are necessary for cleaning wells and, in the case of shale and tight gas wells, use hydraulic fracturing to re-stimulate natural gas formations. The workover of a well is an episodic emission; it is not a part of daily, steady-state well operations, but represents a significant emission from the occasional maintenance of a well. As stated in EPA's technical support document of the petroleum and natural gas industry (EPA, 2011a), conventional wells produce 2.454 Mcf of methane per workover. EPA assumes that the emissions from unconventional well workovers are equal to the emission factors for unconventional well completion (EPA, 2011a). Thus, for unconventional wells, this analysis uses the same emission factors for well completion (discussed above) and well workovers.

Unlike well completions, well workovers occur more than one time during the life of a well. For conventional wells, there were approximately 389,000 wells and 14,600 workovers in 2007 (EPA, 2011a), which translates to 0.037 workovers per well-year. Similarly, for unconventional wells, there were approximately 35,400 wells and 4,180 workovers in 2007 (EPA, 2011a), which translates to 0.118 workovers per well-year.

2.5.3.5 Other Point Source Emissions

Routine emissions from natural gas extraction include gas that is released from wellhead and gathering equipment. These emissions are referred to as "other point source emissions." This analysis assumes that a portion of these emissions are flared, while the balance is vented to the atmosphere. For conventional wells, 51 percent of other point source emissions are flared, while for unconventional wells, a 15 percent flaring rate is used (EPA, 2011a).

Data for the other point source emissions from natural gas extraction are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for onshore and offshore wells. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the methane emission rate by the natural gas production rate in 2006. The emission factors for other point source emissions from natural gas extraction are shown in **Table 2-4**.

2.5.3.6 Other Fugitive Emissions

Routine emissions from natural gas extraction include fugitive emissions from equipment not accounted for elsewhere in NETL's model. These emissions are referred to as "other fugitive emissions," and cannot be captured for flaring. Data for other fugitive emissions from natural gas extraction are based on EPA data for onshore and offshore natural gas wells (EPA, 2011a). EPA's data is based on 2006 production (EPA, 2011a) and shows the annual methane emissions for specific extraction activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas production rate in 2006. The emission factors for other fugitive emissions from natural gas extraction are included in **Table 2-4**.

2.5.3.7 Valve Fugitive Emissions

The extraction of natural gas uses pneumatic devices for the opening and closing of valves and other control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery equipment on all valves and other control devices at a natural gas extraction site, and thus the pneumatic operation of valves results in the emission of fugitive gas.

Data for the fugitive emissions from valves (and other pneumatically-operated devices) are based on EPA data for onshore and offshore gas wells (EPA, 2011a). EPA's data are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific extraction activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas production rate. The emission factors for fugitive valve emissions from natural gas extraction are included in **Table 2-4**.

Table 2-4: Other Point Source and Fugitive Emissions from Natural Gas Extraction

NG Extraction Emission Source	Onshore Extraction	Offshore Extraction	Units
Other Point Source Emissions	7.49E-05	3.90E-05	lb CH_4/lb NG extracted
Other Fugitive Emissions	1.02E-03	2.41E-04	lb CH_4/lb NG extracted
Valve Fugitive Emissions (including pneumatic devices)	2.63E-03	1.95E-06	lb CH_4/lb NG extracted

2.5.3.8 Venting and Flaring

Venting and flaring are necessary in situations where a natural gas (or other hydrocarbons) stream cannot be safely or economically recovered. Venting and flaring may occur when a well is being prepared for operations and the wellhead has not yet been fitted with a valve manifold, when it is not financially preferable to recover the associated natural gas from an oil well or during emergency operations when the usual systems for gas recovery are not available.

The combustion products of flaring at a natural gas well include carbon dioxide, methane, and nitrous oxide. The mass composition of unprocessed natural gas (referred to as "production natural gas") is 78.3 percent CH_4, 1.51 percent CO_2, 1.77 percent nitrogen, and 17.8 percent non-methane hydrocarbons (NMVOCs) (EPA, 2011a). This composition is used to model flaring at the natural gas processing plant. Flaring has a 98 percent destruction efficiency (98 percent of carbon in the flared gas is converted to CO_2), the methane emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2, and N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

2.5.4 Data for Natural Gas Processing

This analysis models the processing of natural gas by developing an inventory of key gas processing operations, including acid gas removal, dehydration, and sweetening. Standard engineering calculations were applied to determine the energy and material balances for the operation of key natural gas equipment. A summary of NETL's natural gas processing data is provided below. **Appendix A** includes comprehensive documentation of the data sources and calculations for NETL's natural gas processing data.

2.5.4.1 Acid Gas Removal

Raw natural gas contains hydrogen sulfide (H_2S), a toxic gas that reduces the heat content of natural gas. Amine-based processes are the predominant technologies for acid gas removal (AGR). The energy consumed by an amine reboiler accounts for the majority of energy consumed by the AGR process. Reboiler energy consumption is a function of the amine flow rate, which, in turn, is related to the amount of H_2S removed from natural gas. The H_2S content of raw natural gas is highly variable, with concentrations ranging from one part per million on a mass basis to 16 percent by mass in extreme cases. An H_2S concentration of 0.5 percent by mass of raw natural gas (Foss, 2004) is modeled in this analysis.

In addition to absorbing H_2S, the amine solution also absorbs a portion of methane from the natural gas. This methane is released to the atmosphere during the regeneration of the amine solvent. The venting of methane from natural gas sweetening is based on emission factors developed by the Gas Research Institute; natural gas sweetening releases 0.000971 lb of methane per lb of natural gas sweetened (API, 2009).

Raw natural gas contains naturally-occurring CO_2 that contributes to the acidity of natural gas. A mass balance around the AGR unit, which balances the mass of gas input with the mass of gas venting and natural gas product, shows that 0.013 lb of naturally-occurring CO_2 is vented per lb of processed natural gas.

Non-methane volatile organic compounds (NMVOCs) are a co-product of AGR. A mass balance shows that 84 percent of the vented gas from the AGR process is NMVOC. They are separated and sold as a high value product on the market. Co-product allocation based on the energy content of the natural gas stream exiting the AGR unit and the NMVOC stream was used to apportion life cycle emissions and other burdens between the natural gas and NMVOC products.

2.5.4.2 Dehydration

Dehydration is necessary to remove water from raw natural gas, which makes it suitable for pipeline transport and increases its heating value. The configuration of a typical dehydration process includes an absorber vessel in which glycol-based solution comes into contact with a raw natural gas stream, followed by a stripping column in which the rich glycol solution is heated in order to drive off the water and regenerate the glycol solution. The regenerated glycol solution (the lean solvent) is recirculated to the absorber vessel. The methane emissions from dehydration operations include combustion and venting emissions. This analysis estimates the fuel requirements and venting losses of dehydration in order to determine total methane emissions from dehydration.

NETL's data for natural gas dehydration accounts for the reboiler used by the dehydration process, the flow rate of glycol solvent, and the methane vented from the regeneration of glycol solvent. All of these activities depend on the concentrations of gas and water that enter and exit the dehydration process. The typical water content for untreated natural gas is 49 lbs. per million cubic feet (MMcf). In order to meet pipeline requirements, the water vapor must be reduced to 4 lbs./MMcf of natural gas (EPA, 2006). The flow rate of glycol solution is three gallons per pound of water removed (EPA, 2006), and the heat required to regenerate glycol is 1,124 Btu/gallon (EPA, 2006).

2.5.4.3 Valve Fugitive Emissions

The processing of natural gas uses pneumatic devices for the opening and closing of valves and other process control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery equipment on all valves and other control devices at a natural gas processing plant, and thus the pneumatic operation of valves results in the emission of fugitive gas.

Data for the fugitive emissions from pneumatic devices are based on EPA data for gas processing plants (EPA, 2011a). EPA's data is based on 2006 production (EPA, 2011a) and shows the annual methane emissions for specific processing activities. This analysis translated EPA's annual data to a unit production basis by dividing the methane emission rate by the natural gas processing rate in 2006. The emission factor for valve fugitive emissions from natural gas processing is included in **Table 2-5**.

2.5.4.4 Other Point Source Emissions

Routine emissions from natural gas processing include gas that is released from processing equipment not accounted for elsewhere in NETL's model. These emissions are referred to as "other point source emissions." This analysis assumes that 100 percent of other point source emissions from natural gas processing are captured and flared.

Data for the other point source emissions from natural gas processing are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific gas processing activities. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the methane emission rate by the natural gas processing rate in 2006. The emission factor for other point source emissions from natural gas processing is included in **Table 2-5**.

2.5.4.5 Other Fugitive Emissions

Routine emissions from natural gas processing include fugitive emissions from processing equipment not accounted for elsewhere in NETL's model. These emissions are referred to as "other fugitive emissions." and cannot be captured for flaring.

Data for the other fugitive emissions from natural gas processing are based on EPA data that are based on 2006 production (EPA, 2011a) and show the annual methane emissions for specific gas processing activities. This analysis translated EPA's data from an annual basis to a unit of production basis by dividing the methane emission rate by the natural gas processing rate in 2006. The emission factor for other fugitive emissions from natural gas processing is included in **Table 2-5**.

Table 2-5: Other Point Source and Fugitive Emissions from Natural Gas Processing

NG Processing Emission Source	Value	Units
Other Point Source Emissions	3.68E-04	lb CH_4/lb NG processed
Other Fugitive Emissions	8.25E-04	lb CH_4/lb NG processed
Valve Fugitive Emissions (including pneumatic devices)	6.33E-06	lb CH_4/lb NG processed

2.5.4.6 Venting and Flaring

The venting and flaring process for natural gas processing is similar to that of natural gas extraction, described in **Section 2.5.3.8**, except all of the other point source emissions at the natural gas processing plant are flared. The combustion products of flaring at a natural gas processing plant include carbon dioxide, methane, and nitrous oxide. The mass composition of pipeline quality natural gas is 92.8 percent CH_4, 0.47 percent CO_2, 0.55 percent nitrogen, and 5.5 percent NMVOCs; this composition is used to model flaring at the natural gas processing plant. Flaring has a 98 percent destruction efficiency (98 percent of carbon in the flared gas is converted to CO_2); the methane emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2; and N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

2.5.4.7 Natural Gas Compression

Compressors are used to increase the natural gas pressure for pipeline distribution. This analysis assumes that the inlet pressure to compressors at the natural gas extraction and processing site is 50 psig and the outlet pressure is 800 psig. Three types of compressors are used at natural gas processing plants: gas-powered reciprocating compressors, gas-powered centrifugal compressors, and electrically-powered centrifugal compressors.

Reciprocating compressors used for industrial applications are driven by a crankshaft that can be powered by 2- or 4-stroke diesel engines. Reciprocating compressors are not as efficient as centrifugal compressors and are typically used for small scale extraction operations that do not justify the increased capital requirements of centrifugal compressors. The natural gas fuel requirements for a gas-powered, reciprocating compressor used for natural gas extraction are based on a compressor survey conducted for natural gas production facilities in Texas (Burklin & Heaney, 2006).

Gas-powered centrifugal compressors are commonly used at offshore natural gas extraction sites. The amount of natural gas required for gas powered centrifugal compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures).

If the natural gas extraction site is near a source of electricity, it has traditionally been financially preferable to use electrically-powered equipment instead of gas-powered equipment. This is the case for extraction sites for Barnett Shale located near Dallas-Fort Worth. The use of electric equipment is also an effective way of reducing the noise of extraction operations, which is encouraged when an extraction site is near a populated area. An electric centrifugal compressor uses the same compression principles as a gas-powered centrifugal compressor, but its shaft energy is provided by an electric motor instead of a gas-fired turbine.

Centrifugal compressors (both gas-powered and electrically-powered) lose natural gas through a process called wet seal degassing, which involves the regeneration of lubricating oil that is circulated between the compressor shaft and housing. This analysis uses an EPA study that sampled venting emissions from 15 offshore platforms (Bylin et al., 2010) and implies a wet seal degassing emission factor of 0.0069 lb of natural gas/lb of processed natural gas.

2.5.5 Data for Natural Gas Transport

This analysis models the transport of natural gas by characterizing key construction and operation activities for pipeline transport. A summary of NETL's natural gas transport data is provided below. **Appendix A** includes comprehensive documentation of the data sources and calculation methods for NETL's natural gas transport data.

2.5.5.1 Natural Gas Transport Construction

The construction of a natural gas pipeline is based on the linear density, material requirements, and length for pipeline construction. A typical natural gas transmission pipeline is 32 inches in diameter and is constructed of carbon steel. Construction is a one-time activity that is apportioned to each unit of natural gas transport by dividing all construction burdens by the book life in years and throughput in million cubic feet of the pipeline.

2.5.5.2 Natural Gas Transport Operations

Data for the operation of a natural gas pipeline are based on national inventory data for methane emissions from natural gas transmission (EPA, 2011b) and a national pipeline compressor survey compiled by EIA (Gaul, 2011). Air emissions from pipeline operations are calculated by applying AP-42 emission factors to the portion of pipeline natural gas that is combusted for compressor power. Seven percent of U.S. natural gas pipeline compressors rely on electric power, and thus the emission profile of the U.S. electricity grid is used to model the emissions associated with electric compressor operations. Finally, the estimated transport capacity of U.S. national gas pipelines (in ton-miles) is applied to the other pipeline variables in order to correlate pipeline emissions with pipeline distance.

2.5.6 Data for Other Energy Sources

The overall goal of this analysis is to understand the greenhouse gas burdens of natural gas extraction and transport. However, the modeling of the conversion of natural gas energy to electricity and electricity transmission is necessary in order to understand how significant extraction and transport are in the cradle-to-grave life cycle context. Additionally, including a comparison both to the upstream greenhouse gases from coal extraction and transport, and the conversion of coal to electricity allows comparison of the fuels on a common basis.

Coal was chosen as a comparable fossil energy source to natural gas that will be used for power production. Because a mix of natural gas sources is developed to represent a domestic production average, a similar method was followed for developing an average domestic coal extraction and transport profile. Two sources of coal are used in the mix, and a wide range of uncertainty is applied to sensitive parameters to ensure the domestic average is captured. The two coal sources are:

- Illinois No. 6 Underground-mined Bituminous
- Powder River Basin Surface-mined Sub-bituminous

Table 2-6 shows the properties used for each type of coal, as well as the proportion of U.S. supply used to create the average profile. The methane content is indicative of what is emitted to the atmosphere during the mining process, not the methane contained in the coal in the formation or after mining.

Table 2-6: Coal Properties

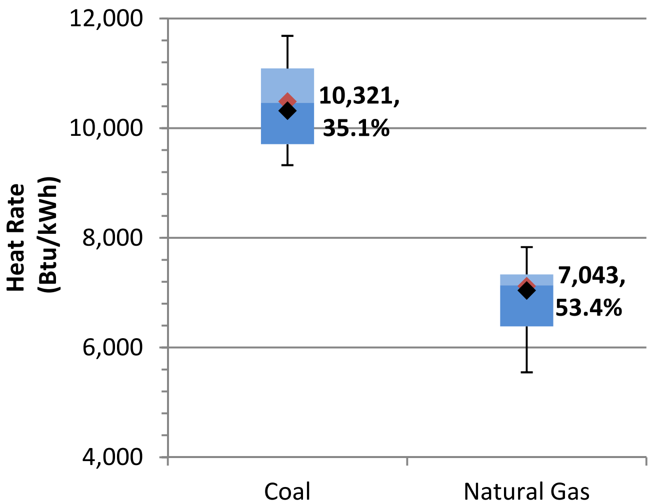
Coal Type	U.S. Supply Share (% by energy)	Energy Content (Btu/lb)	Carbon Content (% by mass)	Methane Emissions (cf CH_4/ton)
Sub-bituminous	69%	8,564	50.1%	8 – 98 (51)
Bituminous	31%	11,666	63.8%	360 – 500 (422)
Average		9,526	54.3%	

Additional information for the Illinois No. 6 profile can be found in the appendix and in the NETL document, *Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant (NETL, 2010e).* Additional information for the Powder River Basin coal extraction and transport profile can be found in the appendix to this document.

2.5.7 Data for Energy Conversion Facilities

The simplest way to compare the full life cycle of coal and natural gas is to produce electricity, although there are alternative uses for both feedstocks. To compare inputs of coal and natural gas on a common basis, production of baseload electricity was chosen. Seven different power plant options are used – three for natural gas and four for coal. Three of the options include carbon capture technology and sequestration infrastructure. Two of the options are U.S. fleet averages based on eGRID data, while the remainder are NETL baseline models. For the U.S. fleet average power plants, **Figure 2-3** shows the distribution of heat rates and associated efficiencies from eGRID. To arrive at the samples shown below, plants smaller than 200MW, with capacity factors lower than 60 percent, and with primary feedstock percentages below 85 percent were cut. The boxes are the first and third quartiles, and the whiskers the 5th and 95th percentiles. The division in the boxes is the median value. The black diamond is the mean, and the orange diamond is the production-weighted mean.

Figure 2-3: Fleet Baseload Heat Rates for Coal and Natural Gas (EPA, 2010)



2.5.7.1 Natural Gas Combined Cycle (NGCC)

The NGCC power plant is based a 555-MW thermoelectric generation facility with two parallel, advanced F-Class gas fired combustion turbines. Each combustion turbine is followed by a heat recovery steam generator that produces steam that is fed to a single steam turbine. The NGCC plant consumes natural gas at a rate of 75,900 kg/hr and has an 85 percent capacity factor. Other details on the fuel consumption, water withdrawal and discharge, and emissions to are detailed in NETL's bituminous baseline (NETL, 2010a). The carbon capture scenario for NGCC is configured a Fluor Econamine carbon dioxide capture system that recovers 90 percent of the CO_2 in the flue gas

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant (NETL, 2010d).*

2.5.7.2 Gas Turbine Simple Cycle (GTSC)

The GTSC plant uses two parallel, advanced F-Class natural gas-fired combustion turbines/generators. The performance of the GTSC plant was adapted from NETL baseline of NGCC power by considering only the streams that enter and exit the combustion turbines/generators and not accounting for any process streams related to the heat recovery systems used by combined cycles. The net output of the GTSC plant is 360 MW and it has an 85 percent capacity factor.

2.5.7.3 U.S. 2007 Average Baseload Natural Gas

The average baseload natural gas plant was developed using data from eGRID on plant efficiency (EPA, 2010). The most recent eGRID data is representative of 2007 electricity production. The average heat rate was calculated for plants with a capacity factor over 60 percent and a capacity greater than 200MW to represent those plants performing a baseload role. The average efficiency (weighted by production, so the efficiency of larger, more productive plants had more weight) was 53.4 percent. This heat rate is applied to the energy content of natural gas (which ranges from 990 and 1,030 Btu/cf) in order to determine the feed rate of natural gas per average U.S. natural gas power. Similarly, the carbon content of natural gas (which ranges from 72 percent to 80 percent) is factored by the feed rate of natural gas, 99 percent oxidation efficiency, and a molar ratio of 44/12 to determine the CO_2 emissions per unit of electricity generation.

2.5.7.4 Integrated Gasification Combined Cycle (IGCC)

The plant modeled is a 640 MW IGCC thermoelectric generation facility located in southwestern Mississippi utilizing an oxygen-blown gasifier equipped with a radiant cooler followed by a water quench. A slurry of Illinois No. 6 coal and water is fed to two parallel, pressurized, entrained flow gasifier trains. The cooled syngas from the gasifiers is cleaned before being fed to two advanced F-Class combustion turbine/generators. The exhaust gas from each combustion turbine is fed to an individual heat recovery steam generator where steam is generated. All of the net steam generated is fed to a single conventional steam turbine generator. A syngas expander generates additional power.

This facility has a capacity factor of 80 percent. For the carbon capture case, the plant is a 556 MW facility with a two-stage Selexol solvent process to capture both sulfur compounds and CO_2 emissions. The captured CO_2 is compressed and transported 100 miles to an undefined geographical storage formation for permanent sequestration, in a saline formation.

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Integrated Gasification Combined Cycle (IGCC) Power Plant (NETL, 2010c).*

2.5.7.5 Supercritical Pulverized Coal (SCPC)

This plant is a 550 MW facility located at a greenfield site in southeast Illinois utilizing a single-train supercritical steam generator. Illinois No. 6 pulverized coal is conveyed to the steam generator by air from the primary air fans. The steam generator supplies steam to a conventional steam turbine generator. Air emission control systems for the plant include a wet limestone scrubber that removes sulfur dioxide, a combination of low-nitrogen oxides burners and overfire air, and a selective catalytic reduction unit that removes nitrogen oxides, a pulse jet fabric filter that removes particulates, and mercury reductions via co-benefit capture.

The carbon capture case is a 546 MW plant configured with 90 percent CCS utilizing an additional sulfur polishing step to reduce sulfur content and a Fluor Econamine FG Plus process. The captured CO_2 is compressed and transported 100 miles to an undefined geographical storage formation for permanent sequestration, in a saline formation.

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant (NETL, 2010e).*

2.5.7.6 Existing Pulverized Coal (EXPC)

This case is an existing pulverized coal power plant that fires coal at full load without capturing carbon dioxide from the flue gas. This case is based on a 434 MW plant with a subcritical boiler that fires Illinois No. 6 coal, has been in commercial operation for more than 30 years, and is located in southern Illinois. The net efficiency of this power plant is 35 percent.

Full description, input data and results for this power plant can be found in the report, *Life Cycle Analysis: Existing Pulverized Coal (EXPC) Power Plant (NETL, 2010b).*

2.5.7.7 U.S. 2007 Average Baseload Coal

Using a similar method to the fleet average natural gas baseload plant, a mean and weighted average efficiency of 35.1 percent were pulled from eGRID. Using the coal characteristics detailed in **Table 2-6**, a feed rate and emissions rate were created.

For each option, the transmission and distribution (T&D) of electricity incurs a 7 percent loss, resulting in the production of additional electricity and extraction of necessary fuel to overcome this loss. All upstream life cycle stages scale according to this loss factor.

Construction is included in the four NETL developed models. It accounts for less than 1 percent of overall greenhouse gas impact, and so was excluded from the total for the fleet average plants.

The performance characteristics of the power plants modeled in this analysis are summarized in **Table 2-7**. Note that for the average natural gas and coal power plants, low, nominal and high values are indicated.

Table 2-7: Power Plant Performance Characteristics

Property			Natural Gas			Coal					
			NGCC	GTSC	Avg. NG	IGCC	IGCC (w/ CCS)	SCPC	SCPC (w/ CCS)	EXPC	Avg. Coal
Performance											
Net Output	MW		555	360	> 200	640	556	550	546	434	> 200
Heat Rate[1]	Btu/kWh	L N H	6,798	11,323	7,334 7,043 6,387	8,756	10,458	8,687	12,002	9,749	11,090 10,321 9,708
Efficiency	%	L N H	50.2%	30.1%	46.5% 48.4% 53.4%	39.0%	32.6%	39.3%	28.4%	35.0%	30.8% 33.1% 35.1%
Capacity Fac.	%		85%	85%	> 60%	80%	80%	85%	85%	85%	> 60%
Feedstocks											
Natural Gas	cf/MWh		6,619	11,025	6,858	-	-	-	-	-	-
Ill. No. 6 Coal	lb/MWh		-	-	-	730	876	745	1,036	734	649
PRB Coal	lb/MWh		-	-	-	-	-	-	-	-	355
Air Emissions											
CO_2	lb/MWh		804	1,100	817	1,723	206	1,768	244	2,075	1,999
CO_2 Capture	%		n/a	n/a	n/a	n/a	90%	n/a	90%	n/a	n/a

[1] L, N, H indicated Low, Nominal (default), and High values, respectively.

2.5.8 Summary of Key Model Parameters

The following table summarizes the key parameters that affect the life cycle results for the extraction of natural gas. This includes the amounts of methane emissions from routine activities, frequency and emission rates from non-routine operations, depths of different well types, flaring rates of vented gas, production rates, and domestic supply shares.

Table 2-8: Key Parameters for Six Types of Natural Gas Sources

<table>
<tr><th>Property (Units)</th><th>Onshore</th><th>Associated</th><th>Offshore</th><th>Tight Sands</th><th>Shale</th><th>CBM</th></tr>
<tr><td colspan="7">Natural Gas Source</td></tr>
<tr><td>Production Rate (Mcf/day)
(Range)</td><td>66
(46 - 86)</td><td>121
(85 - 157)</td><td>2,800
(1,960 - 3,641)</td><td>110
(77 - 143)</td><td>274
(192 - 356)</td><td>105
(73 - 136)</td></tr>
<tr><td colspan="7">Natural Gas Extraction Well</td></tr>
<tr><td>Flaring Rate (%)</td><td colspan="3">51% (41 - 61%)</td><td colspan="3">15% (12 - 18%)</td></tr>
<tr><td>Well Completion (Mcf/episode)</td><td colspan="3">47</td><td>4,657</td><td>11,643</td><td>63</td></tr>
<tr><td>Well Workover (Mcf/episode)</td><td colspan="3">3.1</td><td>4,657</td><td>11,643</td><td>63</td></tr>
<tr><td>Well Workover Frequency (Episode/well/yr)</td><td colspan="3">1.1</td><td colspan="3">3.5</td></tr>
<tr><td>Liquids Unloading (Mcf/episode)</td><td>23.5</td><td>n/a</td><td>23.5</td><td>n/a</td><td>n/a</td><td>n/a</td></tr>
<tr><td>Liquids Unloading Frequency (Episodes/well)</td><td>930</td><td>n/a</td><td>930</td><td>n/a</td><td>n/a</td><td>n/a</td></tr>
<tr><td>Valve Emissions, Fugitive (lb CH_4/Mcf)</td><td colspan="2">0.11</td><td>0.0001</td><td colspan="3">0.11</td></tr>
<tr><td>Other Sources, Point Source (lb CH_4/Mcf)</td><td colspan="2">0.003</td><td>0.002</td><td colspan="3">0.003</td></tr>
<tr><td>Other Sources, Fugitive (lb CH_4/Mcf)</td><td colspan="2">0.043</td><td>0.01</td><td colspan="3">0.043</td></tr>
<tr><td colspan="7">Acid Gas Removal (AGR) and CO_2 Removal Unit</td></tr>
<tr><td>Flaring Rate (%)</td><td colspan="6">100%</td></tr>
<tr><td>CH_4 Absorbed (lb CH_4/Mcf)</td><td colspan="6">0.04</td></tr>
<tr><td>CO_2 Absorbed (lb CO_2/Mcf)</td><td colspan="6">0.56</td></tr>
<tr><td>H_2S Absorbed (lb H_2S/Mcf)</td><td colspan="6">0.21</td></tr>
<tr><td>NMVOC Absorbed (lb NMVOC/Mcf)</td><td colspan="6">6.59</td></tr>
<tr><td colspan="7">Glycol Dehydrator Unit</td></tr>
<tr><td>Flaring Rate (%)</td><td colspan="6">100%</td></tr>
<tr><td>Water Removed (lb H_2O/Mcf)</td><td colspan="6">0.045</td></tr>
<tr><td>CH_4 Emission Rate (lb CH_4/Mcf)</td><td colspan="6">0.0003</td></tr>
<tr><td colspan="7">Valves & Other Sources of Emissions</td></tr>
<tr><td>Flaring Rate (%)</td><td colspan="6">100%</td></tr>
<tr><td>Valve Emissions, Fugitive (lb CH_4/Mcf)</td><td colspan="6">0.0003</td></tr>
<tr><td>Other Sources, Point Source (lb CH_4/Mcf)</td><td colspan="6">0.02</td></tr>
<tr><td>Other Sources, Fugitive (lb CH_4/Mcf)</td><td colspan="6">0.03</td></tr>
<tr><td colspan="7">Natural Gas Compression at Gas Plant</td></tr>
<tr><td>Compressor, Gas-powered Reciprocating (%)</td><td>100%</td><td>100%</td><td></td><td>100%</td><td>75%</td><td>100%</td></tr>
<tr><td>Compressor, Gas-powered Centrifugal (%)</td><td></td><td></td><td>100%</td><td></td><td></td><td></td></tr>
<tr><td>Compressor, Electrical, Centrifugal (%)</td><td></td><td></td><td></td><td></td><td>25%</td><td></td></tr>
<tr><td colspan="7">Natural Gas Emissions on Transmission Infrastructure</td></tr>
<tr><td>Pipeline Transport Distance (mi.)</td><td colspan="6">604 (483 - 725)</td></tr>
<tr><td>Pipeline Emissions, Fugitive (lb CH_4/Mcf-mi.)</td><td colspan="6">0.0003</td></tr>
<tr><td colspan="7">Natural Gas Compression on Transmission Infrastructure</td></tr>
<tr><td>Distance Between Compressors (mi.)</td><td colspan="6">75</td></tr>
<tr><td>Compressor, Gas-powered Reciprocating (%)</td><td colspan="6">78%</td></tr>
<tr><td>Compressor, Gas-powered Centrifugal (%)</td><td colspan="6">19%</td></tr>
<tr><td>Compressor, Electrical, Centrifugal (%)</td><td colspan="6">3%</td></tr>
</table>

3 Inventory Results

This section includes upstream results for the average production case, marginal upstream results, and results after conversion to electricity.

3.1 Average Upstream Inventory Results

This analysis defines upstream activities as the raw material acquisition and transport activities that are necessary for the delivery of fuel to a power plant. The results of this analysis include the upstream GHG emissions for natural gas. For the natural gas supply chain, upstream includes well operations and natural gas processing activities, as well as the pipeline transport of natural gas from the extraction site to a power plant.

Figure 3-1: Upstream Cradle-to-gate Natural Gas GHG Emissions by Source

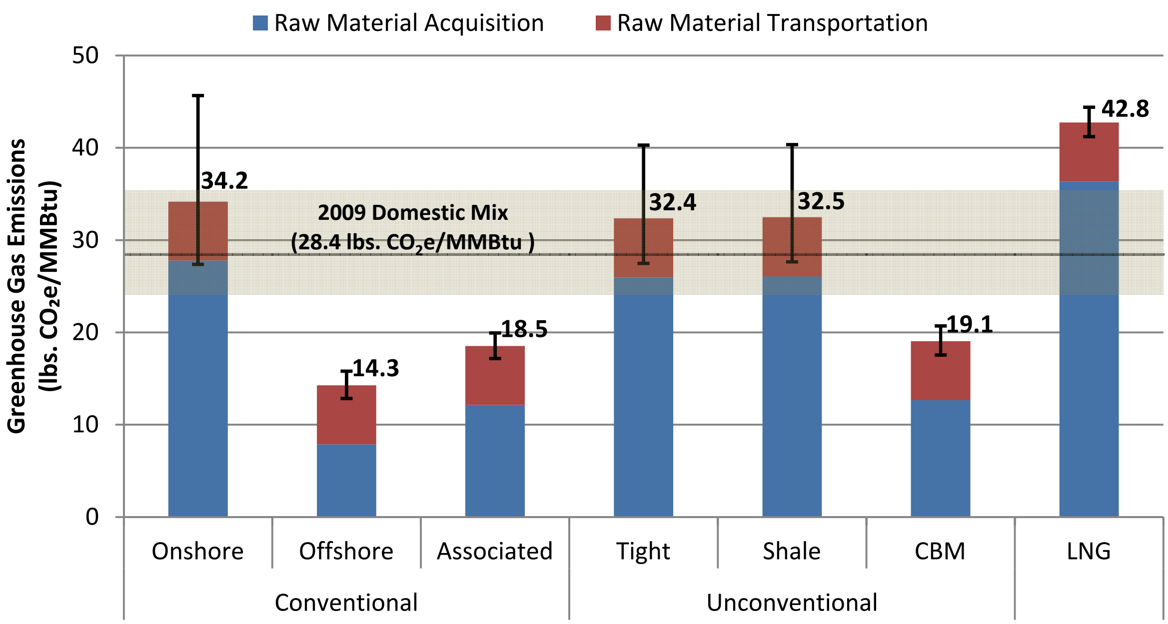


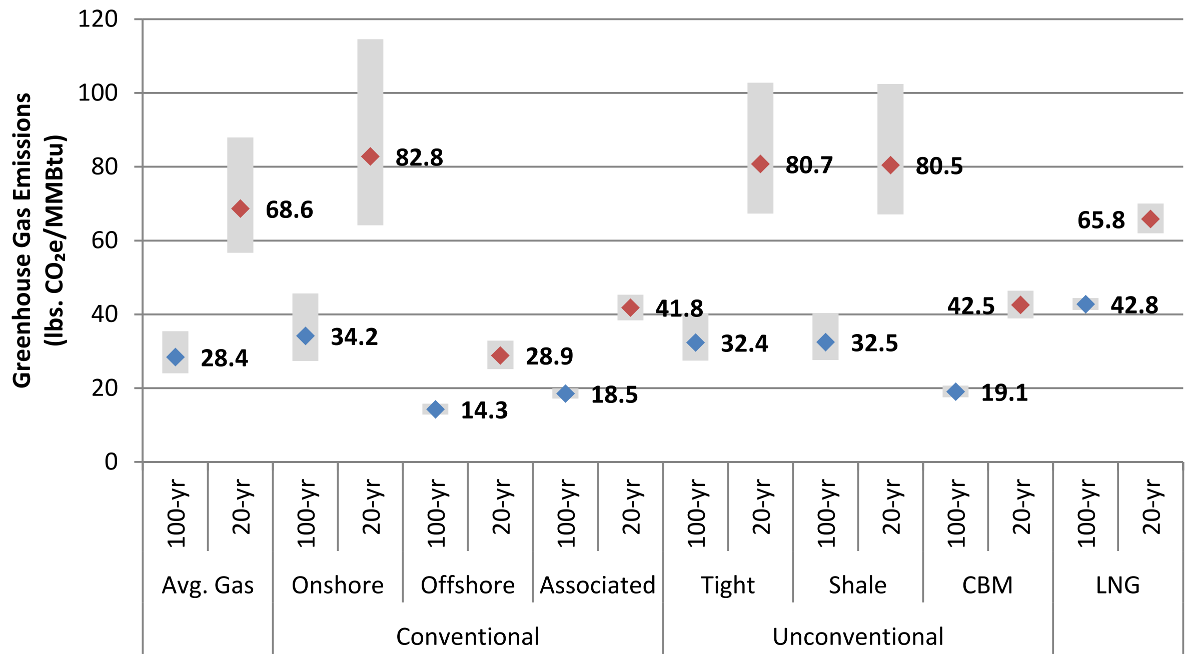
Figure 3-1 shows the comparative upstream greenhouse gases of the six sources of domestic gas, imported liquefied natural gas, and the 2009 mix of all of those sources, broken out by life cycle stage. These results are based on IPCC 100-year GWP. The domestic average of 28.4 lbs. CO_2e/MMBtu and its associated uncertainty are shown overlaying the results for the other types of gas. This average is calculated using the percentages shown in **Table 2-2**. It is worth noting here that the RMT result is the same for all types of natural gas. It is assumed in this study that natural gas is a commodity that is indistinguishable once put on the transport network, so the distance traveled is the same for all types of natural gas. The distance parameter is adjustable, so if a natural gas type with a short distance to markets were evaluated, the RMT value would be smaller.

Offshore sourced natural gas has the lowest greenhouse gases of any source. This is due to the very high production rate of offshore wells and an increased emphasis on controlling methane emissions for safety and risk-mitigation reasons.

Imported gas has a significantly higher greenhouse gases than even domestic unconventional extraction. It is fundamentally an offshore extraction process, which has the lowest GHGs of all the sources. The additional impact is due to the refrigeration, ocean transport and liquefaction processes. Uncertainty is highest for the unconventional sources due to high episodic emissions (well completions, workovers, etc.) and a wide range of observed production rates to allocate those emissions.

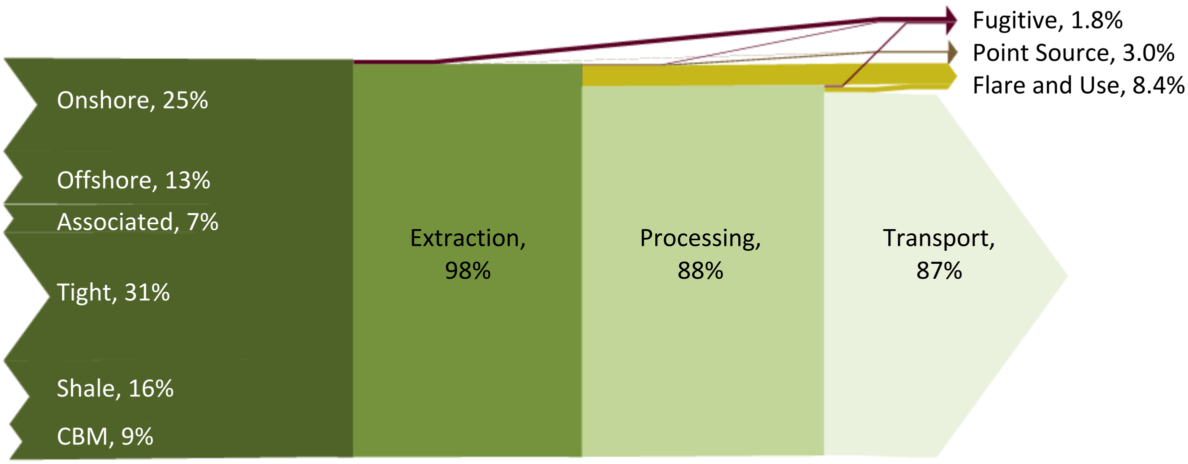
The key sources of GHG emissions in the natural gas supply chain are the combustion of fossil fuels and the venting of methane from natural gas processing and compression equipment.

Figure 3-2: Upstream Cradle-to-gate Natural Gas GHG Emissions by Source and GWP



The results in **Figure 3-2** compare the basic results from **Figure 3-1** across two sets of global warming potentials (detailed in **Table 2-1**). Converting the inventory of greenhouse gases to 20-year GWP, where methane's factor increases from 25 to 72, magnifies the difference between conventional and unconventional sources of natural gas, and the importance of methane losses to the cradle-to-gate GHG results.

Figure 3-3: Cradle-to-Gate Reduction in Extracted Natural Gas



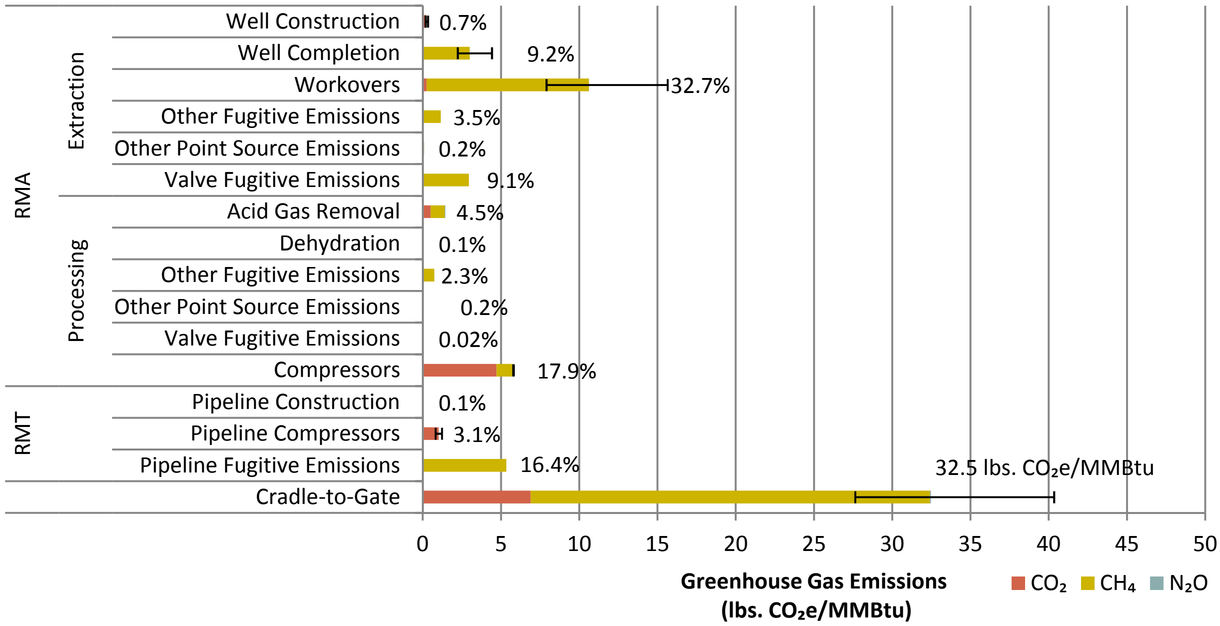
The Sankey diagram shown in **Figure 3-3** shows the reduction in natural gas (not solely methane) from extraction to delivery at the plant gate. This information is also not weighted by global warming potential. **Table 3-1** shows the same information in table form. Of the natural gas extracted from the ground, only 87 percent is delivered to the plant or city gate; 13 percent is either used internally for power, released at a point source and then flared – if applicable, or lost as a fugitive emission. It is important to recognize that not all of this gas is emitted to the atmosphere. In fact, 64 percent of the reduction in natural gas is used to power various processing equipment, most significantly compressors providing motive force for the natural gas. Further, 23 percent are point source emissions, generally concentrated enough to be flared; this, importantly from a climate change perspective, converts the methane to carbon dioxide. Only 13 percent of emissions are considered fugitive: spatially separated emissions difficult to capture or control.

Table 3-1: Natural Gas Losses from Extraction and Transportation

Process	Raw Material Acquisition		Transport	Total
	Extraction	Processing		
Extracted from Ground	100.0%			100.0%
Fugitive Losses	1.2%	0.1%	0.5%	1.8%
Point Source Losses (Vented or Flared)	0.8%	2.2%	0.0%	3.0%
Flare and Fuel Use	0.0%	7.6%	0.8%	8.4%
Delivered to End User				86.9%

By expanding the underlying data in NETL's model, a better understanding of the key contributions to natural gas emissions can be achieved. **Figure 3-4** shows the GHG contribution of specific extraction and transport activities for the Barnett Shale profile. This figure further shows the contribution of methane (CH_4), nitrous oxide (N_2O) and carbon dioxide (CO_2) to the total greenhouse gases. Similar data exists for each source of natural gas, as well as for the domestic average.

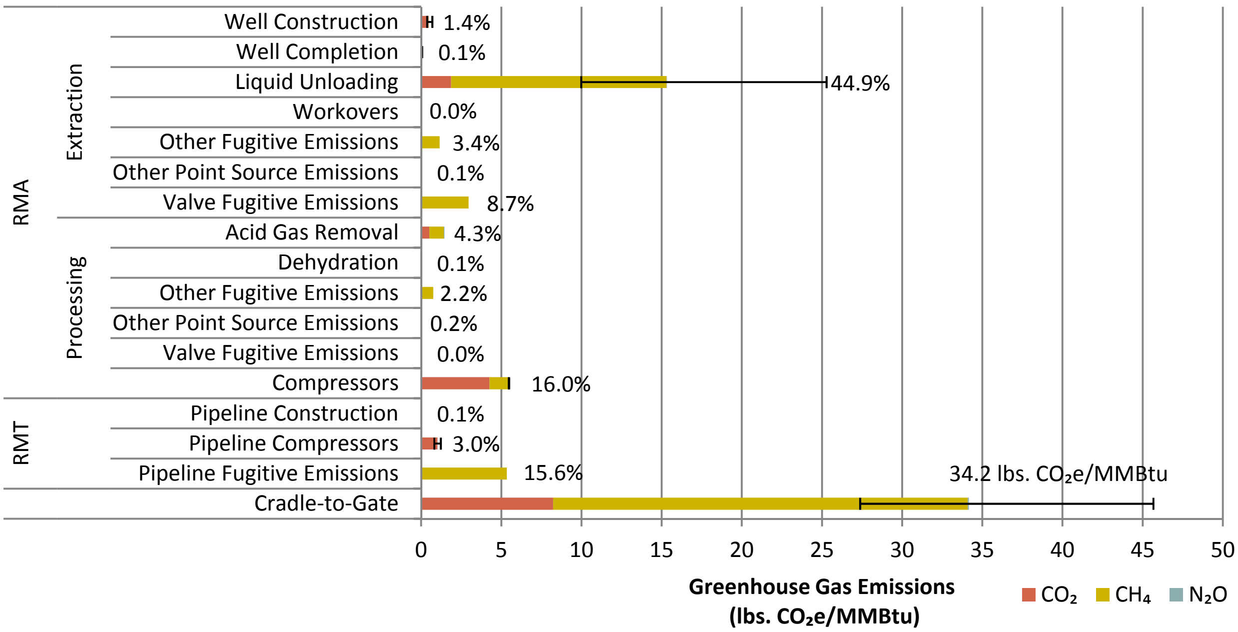
Figure 3-4: Expanded Greenhouse Gas Results for Barnett Shale Gas



This figure shows clearly how important methane is to the total greenhouse gas emissions. In most energy systems, carbon dioxide is the primary concern, but for natural gas extraction, processing and transport, the methane drives the result, and most of the uncertainty. With this unconventional gas, the importance (and associated uncertainty) associated with episodic emissions such as well completion and workover can be seen as well. Well construction, on the other hand, contributes less than 1 percent to the total. Moreover, from the compressors at the last stage of the processing step along with the compressor operations and fugitive emissions on the pipeline, the importance of transport can be seen from these results.

Figure 3-5 shows similar cradle-to-gate results for the natural gas extracted from conventional onshore wells. As with the shale profile, the major contributors are the fuel use and fugitive emissions from the transport, and episodic emissions like liquid unloading. Liquid unloading along contributes 45 percent to the total emissions, and the majority of the uncertainty as well. The uncertainty indicated here is due to a wide range in production rate, not the emission factor for liquids unloading. As discussed in the modeling method, production rate is used to apportion episodic emissions.

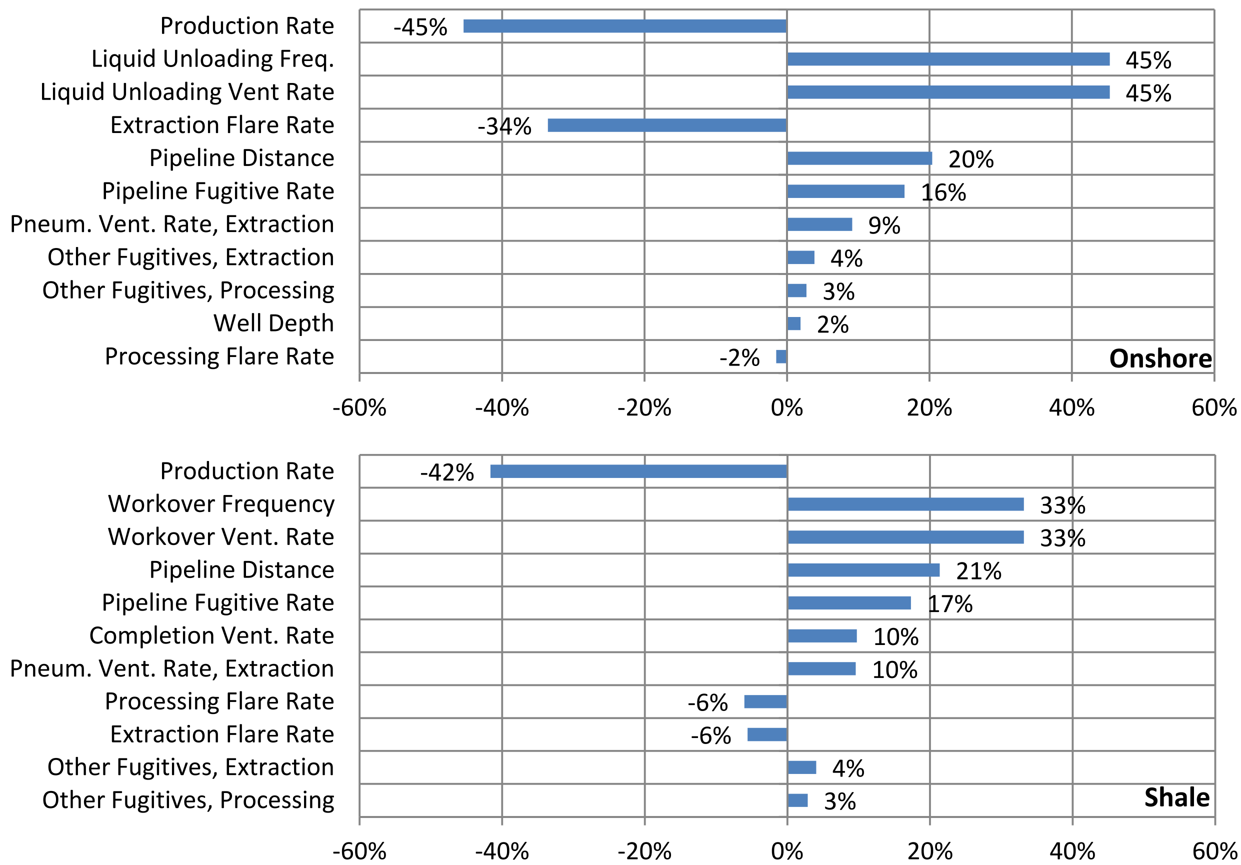
Figure 3-5: Expanded Greenhouse Gas Results for Onshore Natural Gas



This analysis uses a parameterized modeling approach that allows the alteration and subsequent analysis of key variables. Doing so allows the identification of variables that have the greatest effect on results. Sensitivity results are shown in **Figure 3-6**. Parameters were adjusted and displayed regardless of whether uncertainty information was collected for that parameter. Percentages above are relative to a unit change in parameter value; all parameters are changed by the same percentage, allowing comparison of the magnitude of change to the result across all parameters. Positive results indicate that an increase in the parameter leads to an increase in the result. A negative value indicates an inverse relationship; an increase in the parameter would lead to a decrease in the overall result.

For example, a 5 percent increase in shale Production Rate would result in a 2.1 percent (5 percent of 42 percent) decrease in cradle-to-gate GHGs, from 32.5 to 31.8 lbs. CO_2e/MMBtu. A corresponding 5 percent increase in onshore Production rate results in a 2.3 percent decrease to 33.4 lbs. CO_2e/MMBtu. Thus, onshore is more sensitive to changes in production rate than shale gas.

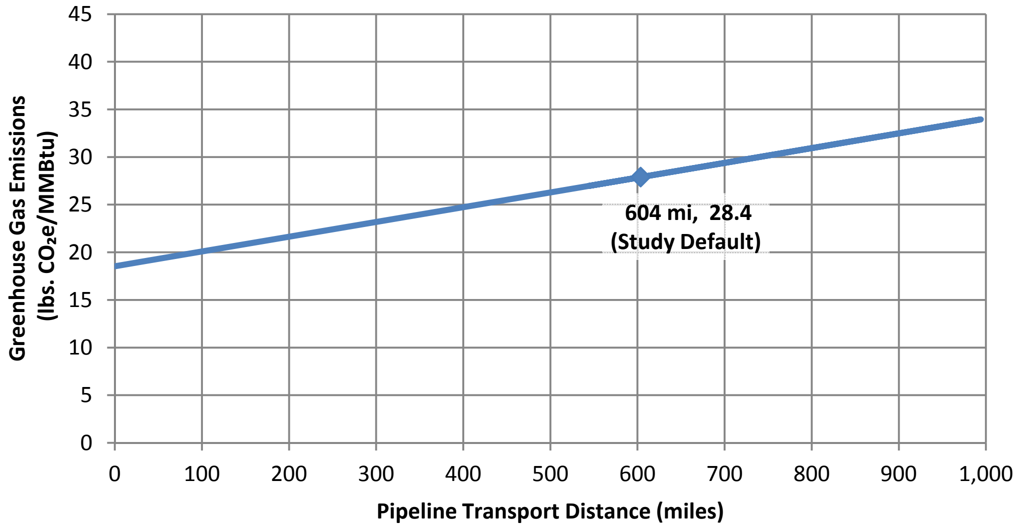
Figure 3-6: Sensitivity of Onshore and Shale GHGs to Changes in Parameters



The results in **Figure 3-6** show that both the onshore and shale profiles are sensitive to changes in pipeline distance, which is currently set to 604 miles for all profiles. As more unconventional sources like Marcellus shale which is close to major demand centers (New York, Boston, Toronto) come on the market, the average distance natural gas has to travel will go down, decreasing the overall impact.

The pipeline transport of natural gas is inherently energy intensive because compressors are required to continuously alter the physical state of the natural gas in order to maintain adequate pipeline pressure. Further, the majority of compressors on the U.S. pipeline transmission network are powered by natural gas that is withdrawn from the pipeline. **Figure 3-7** shows the sensitivity of natural gas losses to pipeline distance. The study default for domestic sources of natural gas is 604 miles, which was determined by solving for the distance at which the per-mile emissions were equivalent to the U.S. annual natural gas transmission methane emissions in 2009. See **Appendix A** for full discussion on determining a default distance.

Figure 3-7: Sensitivity of GHGs Results to Pipeline Distance



3.2 Results for Marginal Production

Marginal production is defined here as the next unit of natural gas produced not included in the average, presumably from a new, highly productive well for each type of natural gas. Since older, less productive wells are ignored as part of these results, the production rate per well is much higher, episodic emissions are spread across more produced gas, and the corresponding GHG inventory is lower. **Table 3-2** shows the production rate assumptions used for both the average and marginal cases.

Table 3-2: Production Rate Assumptions for Average and Marginal Cases

Source	Well Count	Dry Production (Tcf)	Production Rate (Mcf/day)					
			Average			Marginal		
			N	L (-30%)	H (+30%)	N	L (-30%)	H (+30%)
Onshore	216,129	5.2	66	46	86	593	297	1,186
Offshore	2,641	2.7	2,801	1,961	3,641	6,179	3,090	12,358
Associated	31,712	1.4	121	85	157	399	200	798
Tight Sands	162,656	6.6	111	78	144	110	77	143
Shale	32,797	3.3	274	192	356	274	192	356
CBM	47,165	1.8	105	73	136	105	73	136

Results are shown below in **Table 3-3**. The marginal and average production rates for the unconventional sources (tight, shale and CBM) were identical, and so there is no change shown below. There was a significant change in the production rate for all the mature conventional sources. Large numbers of the wells from each of these sources are nearing the end of the useful life, and have dramatically lower production rates, bringing the average far below what would be expected of a new well of each type.

Table 3-3: Average and Marginal Upstream Greenhouse Gas Emissions (lbs CO_2e/MMBtu)

Source		Average	Marginal	Percent Change
Conventional	Onshore	34.2	20.1	-41.2%
	Offshore	14.3	14.1	-1.4%
	Associated	18.5	18.4	-0.8%
Unconventional	Tight	32.4	32.4	0.0%
	Shale	32.5	32.5	0.0%
	Coal Bed Methane	19.1	19.3	1.4%
Liquefied Natural Gas		42.8	42.5	-0.6%

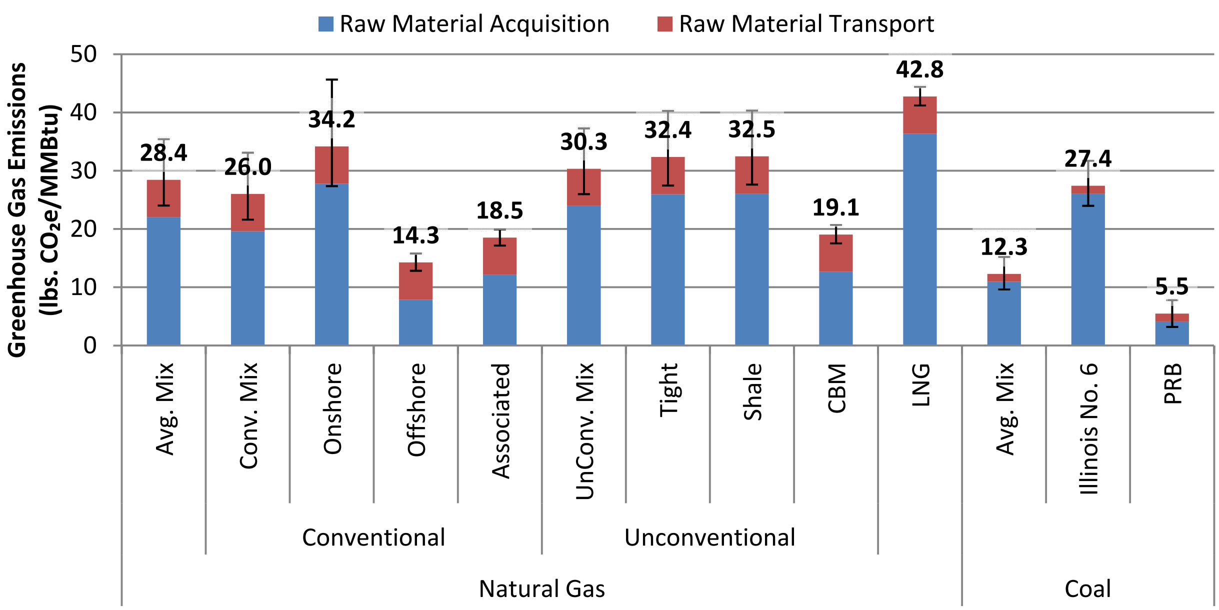
Interestingly, although the production rates for both associated gas and offshore gas change significantly, there is little change to the upstream value: a drop of 0.8 percent and 1.4 percent respectively. This has to do with the characteristics of these types of wells; the flow of natural gas in offshore wells is so strong that there is no need to periodically perform liquids unloading, and for associated wells, the petroleum co-product is constantly removing any liquid in the well. This means the only episodic emission (one which would need to be allocated by lifetime production of the well) is the construction or completion of the well, which is small in both cases, as a percentage of overall emissions.

That leaves onshore conventional production as the only source which shows a significant difference (a drop of 41.2 percent) between the average and marginal production. There are over 200,000 active onshore conventional wells, over 80 percent of which have daily production below the average rate of 138 Mcf/day (EIA, 2010). Yet, when this marginal natural gas is run through electricity generation, there is only a 7 percent drop in greenhouse gas emissions.

3.3 Comparison to Other Fossil Energy Sources

Additional insight can be gained by comparing the life cycle of natural gas power to those of coal. The upstream GHG emissions for various fuels are shown in **Figure 3-8**.

Figure 3-8: Comparison of Upstream GHG Emissions for Various Feedstocks

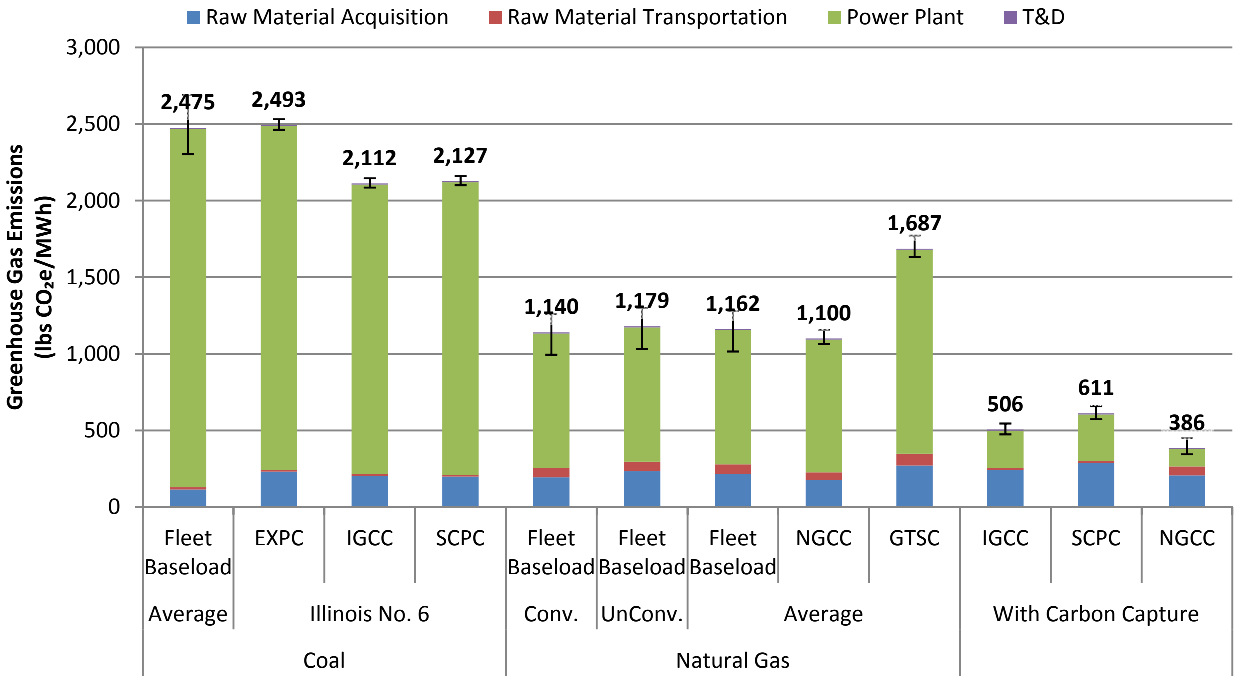


Compared on an upstream energy basis, natural gas has higher GHG emissions than coal. Comparing the domestic mixes from **Figure 3-8**, natural gas is nominally 116 percent more greenhouse gas intense than coal. Gassier bituminous coal such as Illinois No. 6 is more comparable, but only makes up 31 percent of domestic consumption on an energy basis.

3.4 Role of Energy Conversion

The per unit energy upstream emissions comparisons shown above are somewhat misleading in that a unit of coal and natural gas often provide different services. If they do provide the same service, they often do so with different efficiencies—it is more difficult to get useful energy out of coal than it is out of natural gas. To provide a common basis of comparison, different types of natural gas and coal are run through various power plants and converted to electricity. Note that there are alternative uses of both fuels, and as such, different bases on which they could be compared. However, in the United States, the vast majority of coal is used for power production, and so provides the most relevant comparison. **Figure 3-9** compares results for natural gas and coal power on the basis of 1 MWh of electricity delivered to the consumer. In addition to the NETL baseline fossil plants with and without carbon capture and sequestration, these results include a simple cycle gas turbine (GTSC) and representations of fleet average baseload coal and natural gas plants, as described in **Section 2.5.7**.

Figure 3-9: Life Cycle GHG Emissions for Electricity Production



In contrast to the upstream results, which showed a significantly higher GHGs for natural gas than coal, these results show that natural gas power, on a 100-year GWP basis, has a much lower impact than coal power without capture, even when using unconventional natural gas. Even when using less efficient simple cycle turbines, which provide peaking power to the grid, there are far fewer greenhouse gases emitted than for coal-fired power. Because of different the different roles played by these plants, the fairest comparison is the domestic mix of coal run through an average baseload coal power plant with the domestic mix of natural gas run through the average baseload natural gas plant. In that case, the coal-fired plant has emissions of 2,475 lbs. CO_2e/MWh, more than double the emissions of the natural –gas fired plant at 1,162 lbs. CO_2e/MWh.

Figure 3-10 shows the same results but applying and comparing 100- and 20-year IPCC global warming potentials to the inventoried greenhouse gases.

Figure 3-10: Comparison of Power Production GHG Emissions on 100- and 20-year GWPs

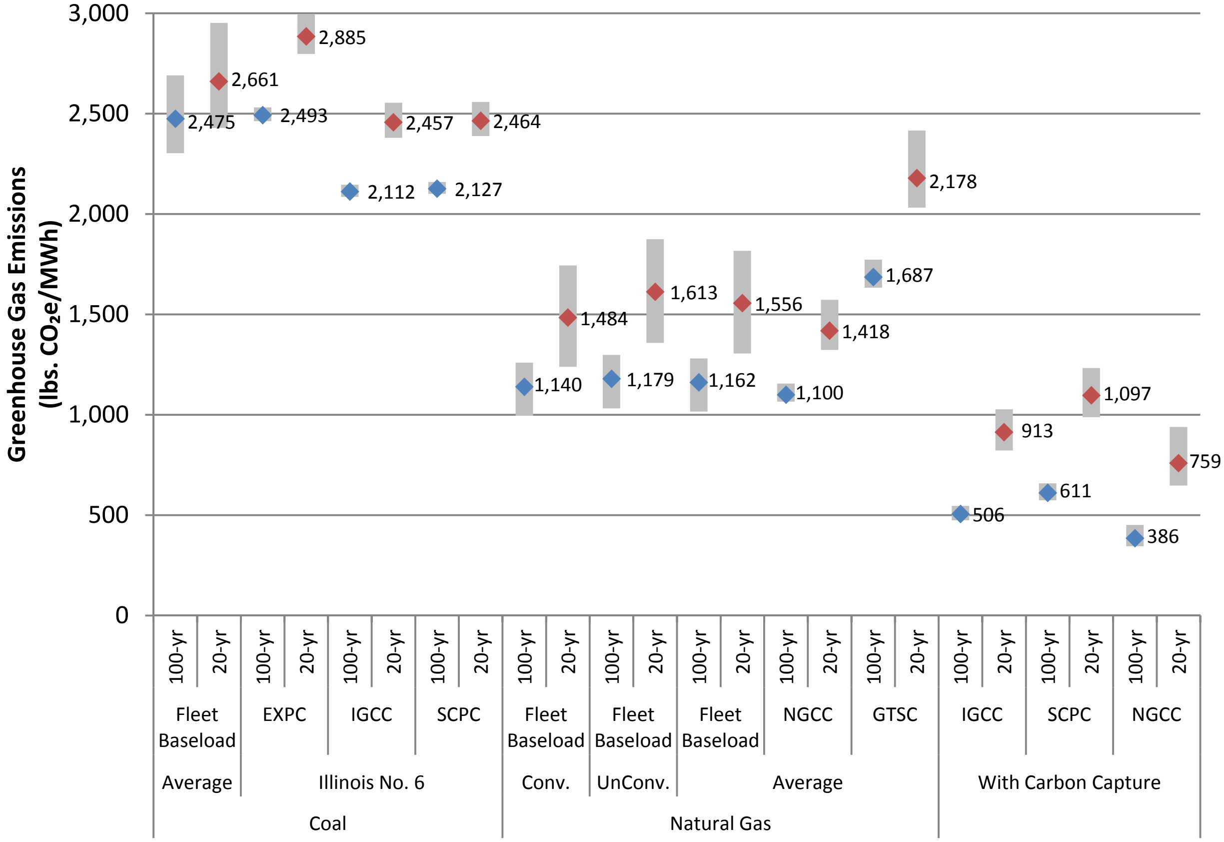


Figure 3-10 shows that even when using a GWP of 72 for CH_4 to increase the relative impact of upstream methane from natural gas, gas-fired power still has lower GHGs than coal-fired power. This conclusion holds across a range of fuel sources (conventional vs. unconventional for natural gas, bituminous vs. average for coal) and a range of power plants (GTSC, NGCC, average for natural gas, and IGCC, SCPC, EXPC, and average for coal). The one situation where this conclusion changed is the use of unconventional natural gas in an NGCC unit with carbon capture compared to an IGCC unit with carbon capture. The high end of the range overlaps the nominal value for IGCC in this situation.

4 Discussion

The following section contains a comparison of the results of this analysis to other natural gas LCAs, a discussion on data limitations, recommendations for improvement and final conclusions.

4.1 Comparison to Other Natural Gas LCAs

Authors at universities and other government labs have conducted research on the natural gas life cycle. The methods and conclusions of three such papers are summarized below.

Life Cycle Assessment of a Natural Gas Combined Cycle Power Generation System (Spath & Mann, 2000)

This NREL study is somewhat dated, having been published in 2000, but using data from the 1990s. It is a high quality study, which makes solid assumptions and tests those assumptions with documented sensitivity analysis. It uses national, annual, top-down information to develop the upstream emissions for natural gas extraction and transportation. Because of this, there are no data specific to unconventional extraction. This study includes not only greenhouse gases but select criteria air emissions and an energy balance. A qualitative impact assessment is performed as well.

Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation (Jaramillo, Griffin, & Matthews, 2007)

This widely cited paper is the most recent publicly available, peer-reviewed study that directly compares life cycle greenhouse gas emissions of power generated from natural gas and coal. Due to concerns regarding gas price volatility at the time the paper was being written, it also includes a comparison of LNG and synthetic natural gas (SNG) from coal. Rather than attempting to represent the next megawatt-hour generated by using best available technology, it looks at average current megawatt-hours generated, so plant efficiencies tend to be lower and emission factors higher. It mixes technologies (NGCC vs. GTSC) and roles (baseload vs. peaking). Like the NREL study, the upstream emissions for both natural gas and coal are top-down numbers. These values are somewhat dated, and represent a homogeneous gas supply rather than breaking out unconventional extraction.

Development of a Top Down Screening Model Using 2011 EPA Greenhouse Gas Inventory

Although this study uses emission factors from the EPA that went into building the 2011 U.S. Greenhouse Gas Inventory, it did not use the annual emissions estimates to generate a top-down value. Rather, some of the EPA emission factors were applied against specific activities, combined with other data sources and standard engineering calculations in a comprehensive hybrid bottom-up approach.

For comparison purposes, NETL performed a top-down analysis of 2009 domestic natural gas production using EPA's 2011 GHG inventory. This top-down approach was not a comprehensive LCA, but was a screening method that resulted in an aggregated, national-level estimate of GHG emissions. The top-down approach gave a GHG result of 36.6 lbs. CO_2e/MMBtu of delivered natural gas to a large end user, with +30 percent and -19 percent uncertainty. NETL's comprehensive LCA model of natural gas gives a GHG result of 28.4 lbs. CO_2e/MMBtu of delivered natural gas, which is 24 percent lower than the top-down value derived from EPA's national inventory. The nominal top-down number from EPA's inventory is within NETL's uncertainty range, but NETL and EPA use many of the same emission factors for natural gas production, and thus an explanation of the 24 percent difference is necessary.

An overarching reason for the difference between EPA's national inventory and NETL's natural gas life cycle analysis model is that EPA's inventory is based on the emissions reported for an entire industry sector over one year, while NETL's model accounts for the operating characteristic of six types of natural gas extraction technologies over a 30-year period and then mixes the six types according to the 2009 U.S. natural gas supply profile. Three specific examples of this fundamental difference between modeling approaches are as follows:

1. A difference in method between activity-based scaling to the national level vs. well-specific production rates that scale results to each of six extraction types.
2. Differences in episodic emission factors for tight gas and the contribution of tight gas to the national inventory.
3. Time series discrepancies inherent in EPA's episodic emission factors.

Clarification on these differences is provided below.

For each type of natural gas well, NETL apportions episodic emission factors based on the production rate of a single well. These apportioned emissions are then compiled according to the relative contribution of each well type to the domestic mix to arrive at the domestic average emissions. EPA's national GHG inventory, on the other hand, does not use well production rates, but uses well activity counts for conventional and unconventional wells to scale up the episodic emission factors to a national level. It is possible that the production rates of the wells that were sampled during the development of EPA's episodic emission factors do not align with the average well production rates applied by NETL. Or the activity counts used by EPA do not align with the contribution of the six natural gas types to the national mix as modeled by NETL.

When modeling tight gas, NETL made adjustments to EPA's emission factors for well completions and workovers. A close look at EPA's documentation (EPA, 2011a) indicates that its unconventional completion and workover emission factors are representative of high-pressure, tight gas wells in the San Juan and Piceance Basins that were completed using a horizontal hydraulic fracturing method and have a high, for tight gas basins, EUR of approximately 2 to 4 BCF. NETL's survey of tight gas production in the U.S. determined that an EUR of 1.2 BCF is more representative of average U.S. tight gas production. The pressure of a well (and, in turn, the volume of natural gas released during completion) is associated with the production rate of a well and therefore was used to scale the methane emission factor for tight gas well completion and workovers. NETL uses an emission factor of 3,670 Mcf CH_4 per episode for the completion and workover of tight gas wells. It is worth noting that EPA does not distinguish between tight sands and shale gas in the annual inventory, a general category of unconventional natural gas is characterized by low and high pressure formations. NETL applied EPA's unconventional completion and workover emission factor for low pressure formations (49.57 Mcf CH_4) reported in Subpart W Technical Support Document (EPA, 2011a) to the coal bed methane well profile and the corresponding high pressure well emission factor to shale gas based on the correlation of representative EUR of 3 BCF for Barnett Shale and the San Juan and Piceance Basin EUR's representing a range of 2 to 4 BCF. While the EPA Subpart W Technical Support Document detailed the results for unconventional well completions and workovers for low pressure formations, the annual inventory (EPA, 2011a) discusses unconventional well activity as a single category assumed to be completed by hydraulic fracture, for the purposes of the inventory, and applies the high pressure formation emission factor of 9,175 Mcf CH_4 for all unconventional well completions and workovers in the annual activity count.

The differences between the top-down and comprehensive approaches is further influenced by whether or not EPA explicitly accounts for tight gas production or simply includes tight gas within its conventional onshore natural gas activity factors. Tight gas represents 31 percent of the 2009 U.S. domestic natural gas supply, and thus the results for NETL's domestic mix are sensitive to changes in the tight gas results (the extent of this sensitivity is demonstrated by the tornado chart for the domestic natural gas mix). It is not clear if EPA includes tight gas within its conventional or unconventional category. If EPA accounts for tight gas in its conventional category, then liquids unloading would be incorrectly assigned to tight gas production, which would result in an overstated result. Alternatively, if EPA accounts for tight gas in its unconventional category, then a well completion and workover emission factor based on high production tight gas formations using horizontal hydraulic fracture was applied, which would result in an overstated result. This difference is only relevant in the comparative context between the two modeling approaches (screening versus comprehensive life cycle analysis). With respect to the purpose of the EPA national inventory approach, the effects are minimized based on the granularity of the overall analysis and the comparison of results at the national sector level. As described above, NETL adjusted the episodic emission factors for tight gas and coal bed methane based on well completion method and production profile.

EPA's documentation of unconventional emission factors are provided in its Subpart W document, which is the basis for its national inventory results (EPA, 2011a). EPA's 2009 GHG inventory is representative of 2009 natural gas production; however, a close look at EPA's Subpart W document reveals that the episodic emission factors are based on relatively small samples of natural gas wells from 2006 and 2007. It is common for LCAs to use data from a broad range of years. However, the behavior of the natural gas industry was especially volatile between 2007 and 2009. The imposition of emission factors that are representative of 2006 and 2007 upon other natural gas data that are representative of anomalous activity in 2009 creates a time-series lag that introduces uncertainty to the emission factor.

Figure 4-1: Natural Gas Well Development vs. Natural Gas Production (EIA, 2011b, 2011c)

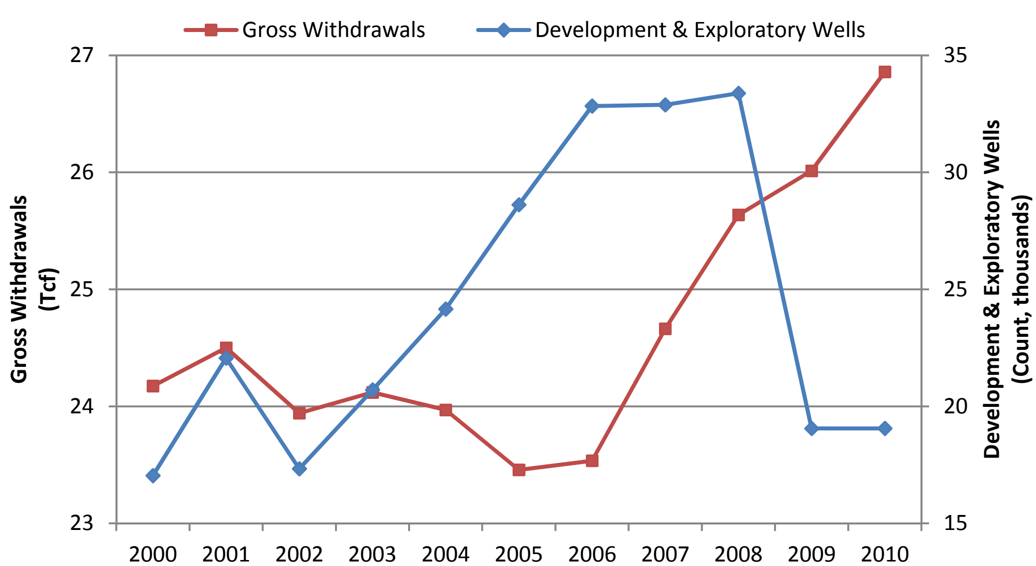


Figure 4-1 shows how increases in natural gas withdrawals lag between five and six years behind the increase in natural gas well drilling activity. Using a numerator with 2006 to 2007 data for well

activity, and 2009 data for withdrawals for the numerator could cause an undefined level of uncertainty in the emission factor. The modeling approaches used by EPA and NETL (as described in the first item above) react differently to this time-series lag. It is possible that NETL's model diminishes these effects because it amortizes the emissions over a 30-year operating period. **Table 4-1** shows the differences among key parameters of the NETL and EPA models.

Table 4-1: Parameter Comparison between NETL and EPA Natural Gas Modeling

Property[1]	Units	NETL						EPA	
		Onshore	Assoc.	Offshore	Tight Sands[2]	Barnett Shale	CBM[3]	Conv.	Unconv.
Contribution to 2009 Mix	Percent	25%	7%	13%	31%	16%	9%	n/a	n/a
Production Rate (30-yr average)	Mcf/day	66	121	2,800	110	274	105	n/a	n/a
Active Wells (2007)	Count	n/a	n/a	n/a	n/a	n/a	n/a	431,035	41,790
Flaring Rate at Well	Percent	51%	51%	51%	15%	15%	51%	51%	15%
Completion Emissions	Mcf CH_4/episode	36.7	36.7	36.7	3,670	9,175	49.6	36.7	9,175
Workover Emissions	Mcf CH_4/episode	2.5	2.5	2.5	3,670	9,175	49.6	2.5	9,175
Workover Frequency	Episodes/year	0.04	0.04	0.04	0.12	0.12	0.12	0.04	0.12
Liquids Unloading Emissions	Mcf CH_4/episode	18.5	n/a	18.5	n/a	n/a	n/a	18.5	n/a
Liquids Unloading Frequency	Episodes/year	31	n/a	31	n/a	n/a	n/a	31	31

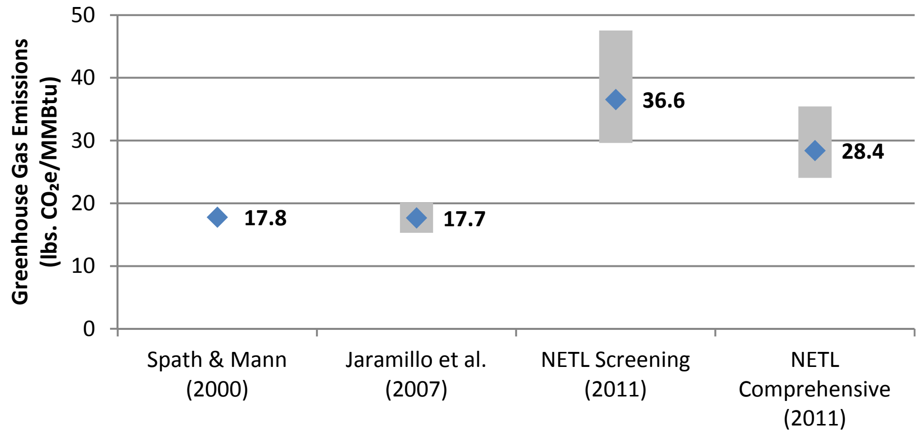
Figure 4-2 shows comparative greenhouse gas emissions from the three studies reviewed above. Results from each study were converted to a common basis of 100-year Global Warming Potential in pounds CO_2e per MMBtu gas delivered. The NREL study did not have an explicit range of values, so the central estimate is shown. For Jaramillo et al., the central estimate is the average of the high and low values.

[1] All emission rates are prior to flaring.

[2] The tight sands emission factor for well completions and workovers was calculated by NETL by reducing EPA's completion and workover factor (3,670 Mcf CH_4) for unconventional wells. The emission rates for completions and workovers are associated with the production rates and reservoir pressures of a well.

[3] The CBM emission factor for well completions and workovers (49.57 Mcf CH_4) is from EPA's documentation of low pressure wells. While CBM wells are an unconventional source of natural gas, they have a low reservoir pressure and thus have lower emission rates from completions and workovers.

Figure 4-2: Comparison of Natural Gas Upstream GHGs from Other Studies



4.2 Data Limitations

A key objective of an LCA is to normalize all data to a common basis (the functional unit). Like all LCAs, this analysis is limited by data uncertainty and data limitations. Key instances of data uncertainty and limitation are summarized below.

4.2.1 Data Uncertainty

Episodic emissions, natural gas production rates, flaring rates, and pipeline distance are four areas of data uncertainty in this analysis and represented within the study results.

Episodic emission factors include the non-routine release of natural gas during well completion, workovers, and liquid unloading. The results of this analysis are sensitive to these episodic emissions. The data for episodic emissions from natural gas wells is limited to a relatively small sample of wells and includes data going back as far as 1996 (EPA, 2011a). These emission factors are not necessarily applicable to all natural gas wells. For instance, it is likely that some unconventional wells have been completed using best practices and thus have low completion emissions, while some conventional wells have been completed with poor practices and thus have high completion emissions. However, there is no basis for claiming that a more recent, larger sampling of natural gas wells would increase or decrease these emission factors.

This analysis uses the production rate for each type of natural gas well for apportioning episodic emissions to a unit of natural gas production. The production rates of unconventional natural gas wells (Barnett Shale, tight gas, and CBM wells) are based on estimated ultimate recovery (EUR) data that are specific to each formation and have specific geographical constraints (Lyle, 2011). Representativeness of unconventional production rate data provides a reasonable confidence range of +/-30 percent. Production data for conventional wells is more variable, exhibiting a 200 percent increase from the low to high production rates. This variability is due to the broad range in age, reservoir, and technology characteristics for conventional wells, making it difficult to define a “typical” conventional natural gas well.

Flaring rate is the portion of vented natural gas that is combusted; the unflared portion is released directly to the atmosphere. Conventional wells flare 51 percent of vented gas, while unconventional wells flare 15 percent of vented natural gas (EPA, 2011a). The natural gas processing plant is modeled at a 100 percent flaring rate. While technology is available to capture and flare virtually all of the vented natural gas from extraction and processing, economics and other practical concerns often prevent the implementation of such technologies. To account for uncertainty, this analysis varied the default values for flaring rates by +/-20 percent. It is likely that there are natural gas wells that fall outside of this range; however, based on professional judgment, we expect this range to account for average natural gas production.

The transmission of natural gas by pipeline involves the combustion of a portion of the natural gas in compressors as well as fugitive losses of natural gas. The total natural gas combustion and fugitive emissions is a function of pipeline distance, which was estimated at an average distance of 604 miles. This distance is based on the characteristics of the entire transmission network and delivery rate for natural gas in the U.S. It is possible that some natural gas sources are located significantly closer to their final markets than other sources of natural gas. To account for this uncertainty, this analysis varies the average pipeline distance by +/- 20 percent, which is an uncertainty range based on professional judgment.

4.2.2 Data Availability

Most data required for this analysis were readily available. However, there are several instances for which more detailed data would enhance the functionality of the LCA model and allow further discernment among natural gas types.

- Formation-specific gas compositions (CH_4, H_2S, NMVOC, and water) for each natural gas type would allow the assignment of specific venting emissions for natural gas extraction and processing. It would also allow the calculation of the specific heat load required for natural gas processing equipment (acid gas removal and dehydration).
- The effectiveness of green completions and workovers would allow further scrutiny of the episodic emissions at wells and, possibly, further data granularity among the three unconventional well types (Barnett Shale, tight gas, and CBM wells).
- No data are available for the fugitive emissions from around wellheads (between the well casing and the ground). This is a possible emission source that could present a significant opportunity for reductions in natural gas losses at a specific wellhead or site, but is not expected to be a significant contribution from an average natural gas perspective.
- Data for water sourcing and production of other fluids used for hydraulic fracturing would expand the boundaries of this analysis further and provide more details on the activities that contribute most to the environmental burdens of unconventional natural gas production and delivery.
- Direct and indirect GHG emissions from land use from access roads and well pads would expand the scope of this analysis further and provide more details on the activities that contribute most to the environmental burdens of unconventional natural gas production and delivery.
- Data for the energy requirements of natural gas exploration would allow further comparisons between conventional and unconventional natural gas. Historically, conventional natural gas fields have been difficult to find, but relatively easy to develop once they are located (NGSA, 2010). In contrast, unconventional gas fields are easy to find, but require significant preparation before natural gas is recovered.

- The energy requirements for the treatment of flowback water from the hydraulic fracturing of unconventional wells would represent an environmental burden that could allow further differentiation among natural gas extraction types.
- The current EPA GHG inventory data for natural gas pipeline emissions includes methane emissions in one category. A split between venting and fugitive emissions from pipeline transport would facilitate recommendations for reducing pipeline losses. Vented emissions may present opportunities for recovery, while fugitive emissions may not represent feasible opportunities for recovery.

4.3 Recommendations for Improvement

Creating a greenhouse gas inventory from a life cycle perspective gives not only a more complete picture of the impact of the process in question, but also allows for identification for the areas of largest impact, and those with the greatest opportunity for improvement. Since this inventory is presented on two different bases, opportunities were identified in both the extraction and delivery of natural gas as well as the production of electricity from natural gas and coal.

4.3.1 Reducing the GHG Emissions of Natural Gas Extraction and Delivery

Unconventional gas sources (shale, tight sands, coal bed methane, etc.) now make up the majority of natural gas extraction. As such, the emissions released during well completion and periodic well workovers are a major contributor to the overall greenhouse gas footprint, and a large opportunity for reduction. However, due to the relatively recent development of unconventional resources, better data is needed to characterize this opportunity based on basin type, drilling method, and production in order to better identify the potential for reductions.

Transportation of processed natural gas to the point at which it is consumed – in this inventory, large end users such as power plants – makes up a large portion of the overall upstream impact. There are two components to this impact: the first is the use of energy to compress the natural gas – the initial compression to put the natural gas on the pipeline, and then periodic compression as the motive force to push the natural gas along the transmission system. The second component is fugitive emissions from joints in the pipeline and other equipment. Improving compressor efficiency not only increases the amount of sellable product, but reduces the greenhouse gases emitted delivering that product. Pipeline fugitive emissions could be reduced with both technology and best management practices.

4.3.2 Reducing the GHG Emissions of Natural Gas and Coal-fired Electricity

Although efforts to reduce methane emissions from natural gas and coal extraction and transportation are important and should be continued, most GHG emissions from their extraction, transportation and use comes in the form of post-combustion carbon dioxide. Three high-level opportunities for reducing these emissions include:

- Capture the CO_2 at the power plant and sequester it in a saline aquifer or oil bearing reservoir
- Improve existing power plant efficiency
- Invest in advanced power research, development, and demonstration

Further, all opportunities need to be evaluated on a sustainable energy basis, considering full environmental performance, as well as economic and social performance, such as the ability to maintain energy reliability and security.

4.4 Conclusions

This greenhouse gas (GHG) analysis inventories six different sources of natural gas, including three types of unconventional gas, combines them into a domestic mix, and then compares the inventory on both a delivered feedstock and delivered electricity basis to a similar domestic mix of coal. The results show that average coal, across a wide range of variability, and compared across different assumptions of climate impact timing, has lower greenhouse gas emissions than domestically produced natural gas when compared as a delivered energy feedstock—over 50 percent less than natural gas per unit of energy.

However, the conclusion that coal is the cleaner fuel flips once the fuels are converted to electricity in power plants with different efficiencies—53 percent for natural gas versus 35 percent for coal. Natural gas-fired electricity has a 42 percent to 53 percent lower climate impact than coal-fired electricity. Even when fired on 100 percent unconventional natural gas, from tight sands, shale and coal beds, and compared on a 20-year GWP, natural gas-fired electricity has 39 percent lower greenhouse gases than coal. This shifting conclusion based on a change in the basis of comparison highlights the importance of specifying an end-use basis—not necessarily power production—when comparing different fuels.

Despite the conclusion that natural gas has lower greenhouse gases than coal on a delivered power basis, the extraction and delivery of the gas has a large climate impact —32 percent of U.S. methane emissions and 3 percent of U.S. greenhouse gases. There are significant emissions and use of natural gas—13 percent at the city or plant gate—even without considering final distribution to small end-users. The vast majority of the reduction in extracted natural gas —70 percent cradle-to-gate—are not emitted to the atmosphere, but can be attributed to the use of the natural gas as fuel for extraction and transport processes such as compressor operations. Increasing compressor efficiency would lower both the rate of use and the CO_2 emissions associated with the combustion of the gas for energy.

But, with methane making up 75 to 95 percent of the natural gas flow, there are many opportunities for reducing the climate impact associated with direct venting to the atmosphere. A further 17 percent of the natural gas losses can be characterized as point source, and have the potential to be flared—essentially a conversion of GWP-potent methane to carbon dioxide.

The conclusions drawn from this inventory and the associated analysis are robust to a wide array of assumptions. However, as with any inventory, they are dependent on the underlying data, and there are many opportunities to enhance the information currently being collected. This analysis shows that the results are both sensitive to and impacted by the uncertainty of a few parameters: use and emission of natural gas along the pipeline transmission network; the rate of natural gas emitted during unconventional gas extraction processes such as well completion and workovers; and the lifetime production of wells, which determine the denominator over which lifetime emissions are placed.

This inventory and analysis are for greenhouse gases only, and there are many other factors that must be considered when comparing energy options. A full inventory of conventional and toxic air emissions, water use and quality, and land use is currently under development, and will allow comparison of these fuels across multiple environmental categories. Further, all opportunities need to be evaluated on a sustainable energy basis, considering full environmental performance, as well as economic and social performance, such as the ability to maintain energy reliability and security.

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Appendix A: Data and Calculations for Greenhouse Gas Inventory

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The energy and material flows tracked by NETL's life cycle analysis (LCA) method in support of this study are used to quantify emissions of greenhouse gases (CO_2, CH_4, and N_2O, SF_6) that would result from natural gas extraction and transport, and from coal extraction and transport. The methods for calculating these flows for the raw material acquisition (RMA) and raw material transport (RMT) of natural gas and coal are provided below.

Some common engineering conversions used in this study are:

- 1 tonne = 1,000 kg
- 1 kg = 2.205 lb
- 1 m^3 = 35.3 cf
- Natural Gas Density: 1 cf of natural gas = 0.042 lb natural gas
- Natural Gas Energy Content: 1,027 Btu/cf natural gas
- The molar ratio of CO_2 to carbon is 44/12

A.1 Raw Material Acquisition: Natural Gas

In this analysis, the boundary of the RMA for natural gas begins with the extraction of natural gas from nature and ends with processed natural gas ready for pipeline delivery. Key activities in the RMA of natural gas are as follows:

- Well construction and installation
- Natural gas sweetening (acid gas removal)
- Natural gas dehydration
- Natural gas venting and flaring
- Natural gas compression
- Well decommissioning

The data sources and assumptions for calculating the greenhouse gas (GHG) emissions from each RMA activity are provided below. In most cases, the methane emissions are calculated by using standard engineering calculations around key gas field equipment, followed by the application of the Environmental Protection Agency (EPA) AP-42 emission factors as necessary.

Well Construction and Installation

NETL's LCA model of natural gas extraction includes the construction and installation activities for natural gas wells. Construction is defined as the cradle-to-gate burdens of key materials that embody key equipment and structures. Installation is defined as the activity of preparing a site, erecting buildings or other structures, and putting equipment in place.

The construction of natural gas wells requires a well casing that provides strength to the well bore and prevents contamination of the geological formations that surround the gas reservoir. In the case of offshore extraction, a large platform is also required. A well is lined with a carbon steel casing that is held in place with concrete. A typical casing has an inner diameter of 8.6 inches, is 0.75 inches thick, and weighs 24 pounds per foot (NaturalGas.org, 2004). The weight of concrete used by the well walls is assumed to be equal to the weight of the steel casing. The total length of a natural gas well is variable, based on the natural gas extraction profile under consideration. The well lengths considered in this study are as follows: conventional onshore: 1,990 m; conventional offshore: 2,660 m; conventional onshore associated: 1,500 m; shale gas: 3,980 m; coal bed methane: 3,980 m; and tight gas: 2,525 m. The total weight of materials for the construction of a well bore is estimated by factoring the total well length by the linear weight of carbon steel and concrete.

The installation of natural gas wells includes the drilling of the well, followed by the installation of the well casing. Horizontal drilling is used for unconventional natural gas reserves where hydrocarbons are dispersed throughout a matrix of shale or coal. An advanced drilling rig has a drilling speed of 17.8 meters per hour, which translates to the drilling of a 7,000 foot well in approximately 10 days (NaturalGas.org, 2004). A typical diesel engine used for oil and gas exploration has a power of 700 horsepower and a heat rate of 7,000 Btu/hp-hr (EPA, 1995). The methane emissions from well installation is the product of the following three variables: heat rate of drilling engine (7,000 Btu/hp-hr), methane emission factor (EPA, 1995) for diesel combustion in stationary industrial engines (6.35E-05 lb/hp-hr), and the total drilling time (in hours).

The daily production rate of a natural gas well is an important factor in apportioning one-time construction activities or intermittent operations to a unit of natural gas production. Typical production rates vary considerably based on well type. Production rates also vary based on well specific factors, such as the age of the natural gas well. For instance, the average daily production rate for new, horizontal shale gas wells in the Barnett Shale region is as high as 2.5 million standard cubic feet (MMcf) per day, but declines at a rapid rate (Hayden & Pursell, 2005). The observed production rates in the Barnett Shale region decline 55 percent during the first year, 25 percent during the second year, 15 percent during the third year, and 10 percent each following year (Hayden & Pursell, 2005). The production rates for each type of natural gas well are shown in **Table A-12**. These production rates include the average production of natural gas wells in 2009 (the basis year of this analysis), as marginal production rates. Marginal production rates exclude poorly performing, mature wells that will likely be removed from service within a couple of years.

The construction and material requirements are apportioned to one kilogram of natural gas product by dividing them by the lifetime production of the well. The natural gas wells considered in this study are presumed to produce natural gas at the rates discussed above, with a lifetime of 30 years. Thus, construction and material requirements, and associated GHG emissions, are apportioned over the lifetime production rate specific to each type of natural gas well, based on average well production rates.

Natural Gas Sweetening (Acid Gas Removal)

Raw natural gas contains varying levels of hydrogen sulfide (H_2S), a toxic gas that reduces the heat content of natural gas and causes fouling when combusted in equipment. The removal of H_2S from natural gas is known as sweetening. Amine-based processes are the predominant technologies for the sweetening of natural gas.

The H_2S content of raw natural gas is highly variable, with concentrations ranging from one part per million on a mass basis to 16 percent by mass in extreme cases. An H_2S concentration of 0.5 percent by mass is modeled in this analysis. This H_2S concentration is based on raw gas composition data compiled by the Gas Processors Association (Foss, 2004).

The energy consumed by the amine reboiler accounts for the majority of energy consumed by the sweetening process. Reboiler energy consumption is a function of the amine flow rate, which, in turn, is related to the amount of H_2S removed from natural gas. Approximately 0.30 moles of H_2S are removed per 1 mole of circulated amine solution (Polasek, 2006), the reboiler duty is approximately 1,000 Btu per gallon of amine (Arnold, 1999), and the reboiler has a thermal efficiency of 92 percent. The molar mass of amine solution is assumed to be 83 g/mole, which is estimated by averaging the molar mass of monoethanolamine (61 g/mole) and diethanolamine (105 g/mole). The density of the amine is assumed to be 8 lb/gal (3.62 kg/gal). The calculation of energy input per kilogram of natural gas product is shown in **Equation 1**.

$$\frac{0.005\ kg\ H_2S}{kg\ NG\ product} * \frac{1\ kg\ mol\ H_2S}{34\ kg\ H_2S} * \frac{1\ kg\ mol\ amine}{0.30 kg\ mol\ H_2S} * \frac{83\ kg\ amine}{kg\ mol\ amine} * \frac{1\ gal\ amine}{3.62\ kg\ amine} * \frac{1{,}000\ Btu\ reboiler\ duty}{gal\ amine} * \frac{1\ Btu\ energy\ input}{0.92\ Btu\ reboiler\ duty} = \frac{12.2\ Btu}{kg\ NG\ product} = \frac{26.9\ Btu}{lb\ NG\ product} \quad \textbf{(Equation 1)}$$

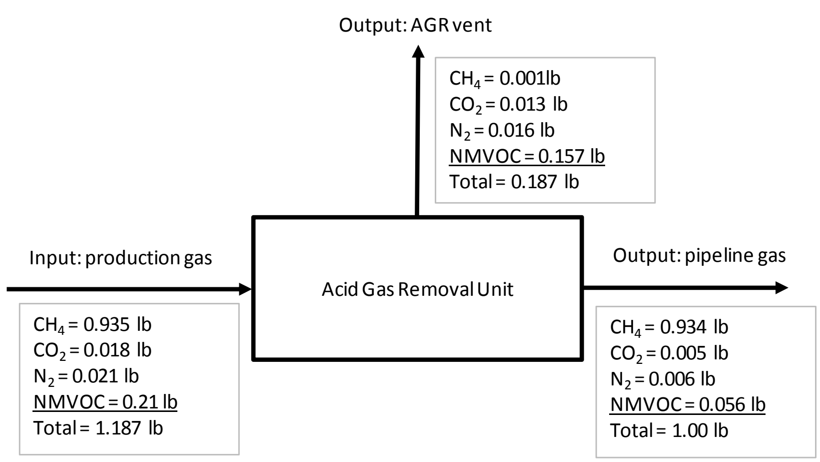
The amine reboiler combusts natural gas to generate heat for amine regeneration. This analysis applies EPA emission factors for industrial boilers (EPA, 1995) to the energy consumption rate discussed in the above paragraph in order to estimate the combustion emissions from amine reboilers.

The sweetening of natural gas is also a source of vented methane emissions. In addition to absorbing H_2S, the amine solution also absorbs a portion of methane from the natural gas. This methane is released to the atmosphere during the regeneration of the amine solvent. The venting of methane from natural gas sweetening is based on emission factors developed by the Gas Research Institute; natural gas sweetening releases 0.000971 lb of methane per lb per natural gas sweetened (API, 2009). The calculation of methane released by amine reboiler venting is shown in **Equation 2**.

$$\frac{0.0185\ tonne\ CH_4}{10^6\ cf\ NG} * \frac{1{,}000\ kg}{tonne} * \frac{2.205\ lb}{kg} * \frac{1cf}{0.042\ lb} = \frac{9.71 \times 10^{-4}\ lb\ CH_4}{lb\ NG} \quad \textbf{(Equation 2)}$$

Raw natural gas contains naturally-occurring CO_2 that contributes to the acidity of natural gas. Most of this CO_2 is absorbed by the amine solution during the sweetening of natural gas and is ultimately released to the atmosphere when the amine is regenerated. This analysis calculates the mass of naturally-occurring CO_2 emissions from the acid gas recovery (AGR) unit by balancing the composition of production gas (natural gas that has been extracted but has not undergone significant processing) and pipeline-quality gas. Production gas contains 1.52 mass percent CO_2 and pipeline-quality natural gas contains 0.47 mass percent CO_2. A mass balance around the AGR unit, which balances the mass of gas input with the mass of gas venting and gas product, shows that 0.013 lb of naturally-occurring CO_2 is vented per lb of processed natural gas. The key constraints of this mass balance are the different compositions of input gas (production gas) and output gas (pipeline-quality gas) and the methane venting rate from amine regeneration. The mass balance around the AGR unit is illustrated by **Figure A-1.**

Figure A-1: Mass Balance for Acid Gas Removal



As shown by the mass balance around the AGR unit, the majority (84 percent by mass) of the AGR vent stream is NMVOC. At this concentration, NMVOCs are a high-value energy product. Thus, from an LCA perspective, NMVOCs are a valuable co-product of the AGR process. Co-product allocation is used to apportion life cycle emissions and other burdens between the natural gas and NMVOC products.

In this analysis, the relative energy contents of the natural gas and NMVOC outputs from the AGR process are used as the basis for co-product allocation. The heating value of pipeline-quality natural gas is 24,452 Btu/lb (which is calculated from the default study value of 1,027 Btu/cf). The heating value of NMVOCs is 21,025 Btu/lb, which is calculated from the composition of the vent stream from the AGR unit and the heating values of each NMVOC component (The Engineering Toolbox, 2011); the calculation of the heating value of NMVOC is shown in **Table A-1**. As shown by the mass balance (**Figure A-1**), 0.157 lbs of NMVOC are produced for every lb of natural gas produced. When these mass flows are converted to an energy basis using the above heating values, 88.1 percent of the product leaving the AGR process is natural gas and 11.9 percent is NMVOCs. Thus, the natural gas model allocates 88.1 percent of the energy requirements and environmental emissions of acid gas removal to the natural gas product.

Table A-1: Heating Value of NMVOC Co-Product from AGR Process

NMVOC Component	Percent Mass	Heating Value (Btu/lb)
CH_4	0%	23,811
Ethane	44.1%	20,525
Propane	26.7%	21,564
Iso-Butane	5.9%	21,640
n-Butane	10.4%	21,640
iso-Pentane	3.0%	20,908
n-Pentane	3.9%	20,908
Hexanes	3.0%	20,526
Heptanes Plus	2.9%	21,000
Other (N_2 and CO_2)	0%	0
Composite Heating Value		21,025

The following table shows the energy consumption and GHG emissions for acid gas removal. These energy and emission factors do not account for the co-product allocation between natural gas and NMVOCs. The co-product allocation between natural gas and NMVOC is performed within the modeling software (GaBi).

For **Table A-2**, the energy used for acid gas removal is based on a 0.005 kg H_2S per of raw natural gas, a molar loading of 0.30 mol H2S per mole of amine solution, and a reboiler duty of 1,000 Btu/gal of regenerated amine, and a reboiler efficiency of 92 percent. The CH_4 venting factor assumes that the reboiler vent is not flared.

Table A-2: Acid Gas Removal (Sweetening)

Flow Name	Value	Units	Reference
Air Emission Factors			
CO_2	2.86	lb CO_2/lb NG fuel	API 2009
N_2O	1.52E-05	lb N_2O/lb NG fuel	API 2009
CH_4 (combustion)	5.48E-05	lb CH_4/lb NG fuel	API 2009
Energy Inputs and Outputs			
Reboiler energy	26.9	Btu/lb NG product	calculated
Reboiler fuel	2.26E-04	lb NG fuel/lb NG product	calculated
Air Emissions			
CO_2 (combustion)	6.47E-04	lb CO_2/lb NG product	calculated
CO_2 (vented)	0.013	lb CO_2/lb NG product	calculated
N_2O	3.54E-06	lb N_2O/lb NG product	calculated
CH_4 (combustion)	1.27E-05	lb CH_4/lb NG product	calculated
CH_4 (vented)	9.71E-04	lb CH_4/lb NG product	API 2009
NMVOC (vented)	0.157	lb NMVOC/lb NG product	calculated

Natural Gas Dehydration

Dehydration is necessary to remove water from raw natural gas, which makes it suitable for pipeline transport and increases its heating value. The configuration of a typical dehydration process includes an absorber vessel in which glycol-based solution comes into contact with a raw natural gas stream, followed by a stripping column in which the rich glycol solution is heated in order to drive off the water and regenerate the glycol solution. The regenerated glycol solution (the lean solvent) is recirculated to the absorber vessel. The methane emissions from dehydration operations include combustion and venting emissions. This analysis estimates the fuel requirements and venting losses of dehydration in order to determine total methane emissions from dehydration.

The fuel requirements of dehydration are a function of the reboiler duty. Due to the heat integration of the absorber and stripper streams, the reboiler, which is heated by natural gas combustion, is the only equipment in the dehydration system that consumes fuel. The reboiler duty (the heat requirements for the reboiler) is a function of the flow rate of glycol solution, which, in turn, is a function of the difference in water content between raw and dehydrated natural gas. The typical water content for untreated natural gas is 49 lbs/MMcf. In order to meet pipeline requirements, the water vapor must be reduced to 4 lbs/MMcf of natural gas (EPA, 2006). The flow rate of glycol solution is 3 gallons per pound of water removed (EPA, 2006), and the heat required to regenerate glycol is 1,124 Btu/gal (EPA, 2006). By factoring the change in water content, the glycol flow rate, and boiler heat requirements, the energy requirements for dehydration are 152,000 Btu/MMcf of dehydrated natural gas (as shown by **Equation 3** and **Equation 4** below). Assuming that the reboiler is fueled by natural gas, this translates to 1.48E-04 lb of natural gas combusted per lb of dehydrated natural gas (as shown by the equations below). The emission factor for the combustion of natural gas in boiler equipment produces 2.3 lb CH_4/million cf natural gas (API, 2009). After converting to common units, the above fuel consumption rate and methane emission factor translate to 8.09E-09 lb CH_4/lb NG treated.

$$\frac{3.00\ gal\ glycol}{lb\ water} * \frac{1{,}124\ Btu}{gal\ glycol} * \frac{(49-4)\ lb\ water}{MMCF\ NG} = \frac{152{,}000\ Btu}{MMcf\ NG} \qquad \textbf{(Equation 3)}$$

$$\frac{152{,}000\ Btu}{MMcf\ NG} * \frac{MMcf\ NG}{10^6 cf\ NG} * \frac{1\ cf\ NG}{1027\ Btu} = \frac{1.48\times10^{-4}\ lb\ NG\ fuel}{lb\ NG\ product} \qquad \textbf{(Equation 4)}$$

In addition to absorbing water, the glycol solution also absorbs methane from the natural gas stream. This methane is lost to evaporation during the regeneration of glycol in the stripper column. Flash separators are used to capture most of methane emissions from glycol strippers; nonetheless, small amounts of methane are vented from dehydrators. The emission of methane from glycol dehydration is based on emission factors developed by the Gas Research Institute (API, 2009). Based on this emission factor, 8.06E-06 lb of methane is released for every pound of natural gas that is dehydrated.

For **Table A-3**, the energy used for dehydration is based on 3 gallons of glycol per pound of water removed, a reboiler duty of 1,124 Btu per gallon of glycol regenerated, and 45 pounds of water removed per MMcf of natural gas produced. The methane venting factor assumes that no flash separator is used to control venting emissions.

Table A-3: Natural Gas Dehydration

Flow Name	Value	Units	Reference
Air Emission Factors			
CO_2	2.86	lb CO_2/lb NG fuel	API 2009
N_2O	1.52E-05	lb N_2O/lb NG fuel	API 2009
CH_4 (combustion)	5.48E-05	lb CH_4/lb NG fuel	API 2009
Energy Inputs and Outputs			
Reboiler energy	1.52E-01	Btu/cf NG product	API 2009
Reboiler fuel	1.48E-04	lb NG fuel/lb NG product	calculated
Air Emissions			
CO_2	4.24E-04	lb CO_2/lb NG product	calculated
N_2O	2.26E-09	lb N_2O/lb NG product	calculated
CH_4 (combustion)	8.10E-09	lb CH_4/lb NG product	calculated
CH_4 (venting)	8.06E-06	lb CH_4/lb NG product	API 2009

Natural Gas Venting and Flaring

Venting and flaring are necessary in situations where a natural gas (or other hydrocarbons) stream cannot be safely or economically recovered. Venting and flaring may occur when a well is being prepared for operations and the wellhead has not yet been fitted with a valve manifold, when it is not financially preferable to recover the associated natural gas from an oil well, or during emergency operations when the usual systems for gas recovery are not available.

The combustion products of flaring include carbon dioxide, methane, and nitrous oxide. The flaring emission factors published by the American Petroleum Institute (API, 2009) are based on the following recommendations by the Intergovernmental Panel on Climate Change (IPCC):

- If measured data are not available, assume flaring has a 98 percent destruction efficiency. Destruction efficiency is a measure of how much carbon in the flared gas is converted to CO_2 (API, 2009).
- The CO_2 emissions from flaring are the product the destruction efficiency, carbon content of the flared gas, the molar ratio of CO_2 to carbon (44/12). Methane is 75 percent carbon by mass, and the other hydrocarbons in natural gas are approximately 81 percent carbon by mass

(Foss, 2004); the composite carbon content of natural gas is calculated by factoring these carbon compositions with the natural gas composition.

- Methane emissions from flaring are equal to the two percent portion of gas that is not converted to CO_2 (API, 2009).
- N_2O emissions from flaring are based on EPA AP-42 emission factors for stationary combustion sources (API, 2009).

The mass composition of unprocessed natural gas (referred to as "production natural gas") is 78.8 percent CH_4, 1.5 percent CO_2, 1.78 percent nitrogen, and 17.9 percent non-methane hydrocarbons (NMVOCs) (EPA, 2011a). The mass composition of pipeline quality natural gas is 93.4 percent CH_4, 0.47 percent CO_2, 0.55 percent nitrogen, and 5.6 percent NMVOCs. The composition of production natural gas to model flaring during natural gas extraction, and the composition of pipeline quality natural gas is used to model flaring at the natural gas processing plant. The above method for estimating flaring emissions was applied to these gas compositions to develop flaring emission factors for production and pipeline natural gas. The following table summarizes the mass composition and flaring emissions for these two gas compositions.

Table A-4: Natural Gas Flaring

Emission	Production NG	Pipeline NG	Units	Reference
Natural Gas Composition				
CH_4	78.8%	93.4%	% mass	(EPA, 2011a)
CO_2	1.52%	0.47%	% mass	(EPA, 2011a)
Nitrogen	1.78%	0.55%	% mass	(EPA, 2011a)
NMVOC	17.90%	5.57%	% mass	(EPA, 2011a)
Flaring Emissions				
CO_2	2.67	2.69	lb CO_2/lb flared NG	API, 2009
N_2O	8.95E-05	2.79E-05	lb N_2O/lb flared NG	API, 2009
CH_4	1.53E-02	1.81E-02	lb CH_4/lb flared NG	API, 2009

The venting rate of natural gas is necessary to apply the above emission factors to a unit of natural gas production. Venting rates are highly variable and depend more on the production practices and condition of equipment at an extraction site that the type of natural gas reservoir. Thus, venting rates have been parameterized in the model to allow uncertainty analysis.

Recent data indicate that only 51 percent of vented natural gas from conventional natural gas extraction operations is flared and the remaining 49 percent is released to the atmosphere (EPA, 2011a). The flaring rate is even lower for unconventional wells, which flare 15 percent of vented natural gas (EPA, 2011a). The flaring rate at natural gas processing plants is assumed to be 100 percent.

Venting from Well Completion

The methane emissions from the completion of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells produce 36.65 Mcf/completion and unconventional wells produce 9,175 Mcf/completion (EPA, 2011a). Barnett Shale and tight gas wells are high pressure wells, and thus have higher completion venting than coal bed methane and conventional wells (EPA, 2011a).

When modeling tight gas, adjustments were made to EPA's emission factors for well completions and workovers. EPA's documentation (EPA, 2011a) indicates that its unconventional completion and workover emissions are representative of high-pressure, tight gas wells in the San Juan and Piceance basins, which are horizontal wells that were completed using hydraulic fracturing and have an estimated ultimate recovery of 3 Bcf. A survey of tight gas production in the U.S. determined that an estimated ultimate recovery of 1.2 Bcf is more representative of U.S. tight gas production. The pressure of a well (and, in turn, the volume of natural gas released during completion) is associated with the production rate of a well and therefore was used to scale the methane emission factor for tight gas well completion and workovers. An emission factor of 3,670 Mcf CH_4 per episode for the completion and workover of tight gas wells is used.

Tight gas emissions are not the only emission factor adjusted for the model. While coal bed methane (CBM) wells are an unconventional source of natural gas, they have a low reservoir pressure and thus have relatively low emission rates from completions and workovers. The CBM emission factor used for the completion and workover of CBM wells is 49.57 Mcf CH_4 (EPA, 2011a). This is much lower than the completion and workover emission factor that EPA recommends for unconventional wells (9,175 Mcf CH_4).

The analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. Using a natural gas density of 0.042 lb/cf (API, 2009) the methane emissions from conventional well completions are 1,538 lb/completion (698 kg/completion). For unconventional wells the venting rates are 386,000 lb/completion (175,000 kg/completion) for Barnett Shale, 2,090 lb/completion (946 kg/completion) for coal bed methane, and 154,000 lb/completion (70,064 kg/completion) for tight gas (EPA, 2011a).

Venting from Well Workovers

The methane emissions from the workover of conventional and unconventional wells are based on emission factors developed by EPA (EPA, 2011a). Conventional wells produce 2.454 Mcf/workover and unconventional wells produce 9,175 Mcf/workover. (Note that the workover emission factor for unconventional wells is the same as the completion emission factor for unconventional wells.) This analysis tracks flows on a mass basis, so it is necessary to convert these emission factors from a volumetric to a mass basis. Using a natural gas density of 0.042 lb/cf (API, 2009) and the conversion factor of 2.205 lb/kg, the methane emissions from well workovers are 103 lb/workover (46.7 kg/workover) for conventional wells. The workover venting rates for unconventional wells are assumed to be equal to their completion venting rates (EPA, 2011a).

Unlike well completions, well workovers occur more than one time during the life of a well. The frequency of well workovers was calculated using EPA's accounting of the total number of natural gas wells in the U.S. and the total number of workovers performed per year (all data representative of 2007). For conventional wells, there were approximately 389,000 wells and 14,600 workovers in 2007 (EPA, 2011a), which translates to 0.037 workovers per well-year. Similarly, for unconventional wells, there were approximately 35,400 wells and 4,180 workovers in 2007 (EPA, 2011a), which translates to 0.118 workovers per well-year.

Venting from Liquid Unloading

Liquid unloading is necessary for conventional gas wells. It is not necessary for unconventional wells or associated gas wells.

The methane emissions from the unloading of liquid from conventional wells are based on emission factors developed by EPA. In 2007, conventional wells produced 223 Bcf/year (EPA, 2011a), which is 4.25 million metric tons per year using a natural gas density of 0.042 lb/cf. There were approximately 389,000 unconventional wells in 2007. When the annual emissions are divided by the total number of wells, the resulting emission factor is 10.9 metric tons per well-year.

Liquid unloading is a routine operation for conventional gas wells. The frequency of liquid unloading was calculated using EPA's assessment of two producers and the unloading activities for their wells (EPA, 2011a). From this sampling, EPA calculated that there are 31 liquid unloading episodes per well-year (EPA, 2011a).

When the emission factor for liquid unloading is divided by the average number of unloading episodes, the resulting methane emission factor is 776 lb/episode (352 kg/episode).

Venting from Wet Seal Degassing

The emission factor for wet seal degassing accounts for the natural gas lost during the regeneration of wet seal oil, which is used for centrifugal compressors. This analysis uses an EPA study that sampled venting emissions from 15 offshore platforms (Bylin et al., 2010). According to EPA's sampling of these platforms, the emissions from wet seal oil degassing are 33.7 million m^3 of methane annually. These platforms produce 4.88 billion m^3 of natural gas annually. When the emission rate for this category is divided by the production rate, the resulting emission factor is 0.00690 m^3 of vented gas per m^3 of produced gas. Assuming the emissions have the same density as the produced gas, this emission factor is 0.00690 lb of natural gas/lb produced natural gas.

Fugitive Emissions from Pneumatic Devices

The extraction and processing of natural gas uses pneumatic devices for the opening and closing of valves and other process control systems. When a valve is opened or closed, a small amount of natural gas leaks through the valve stem and is released to the atmosphere. It is not feasible to install vapor recovery equipment on all valves and other control devices at a natural gas extraction or processing site. Thus, this analysis assumes that the operation of pneumatic systems result in the emission of fugitive natural gas emissions.

Data for the fugitive emissions from pneumatic devices are based on EPA data for offshore wells, onshore wells, and gas processing plants (EPA, 2011a). EPA’s data is based on 2006 production (EPA, 2011a) and shows the methane emissions for specific wellhead and processing activities. This analysis translated EPA’s data to a basis of lb methane per lb of natural gas production by dividing the methane emission rate by the natural gas production rate. For example, the annual emissions from pneumatic devices used for offshore production are 7 MMcf of methane; when divided by the annual offshore production rate of 3,584,190 MMcf, this translates to an emission factor of 1.95E-06 lb of methane per lb of natural gas produced (this calculation assumes that the volumetric densities of methane and natural gas are the same). The fugitive emissions from pneumatic devices used by offshore wells, onshore wells, and natural gas processing plants are shown in the following table.

Table A-5: Fugitive Emissions from Pneumatic Devices

Location	MMcf/yr (EPA, 2011a)		Emission Factor
	CH_4 emission	NG Production	lb CH_4/lb NG
Onshore	52,421	19,950,828	2.63E-03
Offshore	7.0	3,584,190	1.95E-06
Processing	93	14,682,188	6.33E-06

Other Point Source and Fugitive Emissions

The emissions described above account for natural gas emissions from specific processes, including the episodic releases of natural gas during well completion, workovers, and liquid unloading, as well as routine releases from wet seal degassing, AGR, and dehydration. Natural gas is also released by other extraction and processing equipment. To account for these other emissions, NETL's model includes two additional emission categories: other point source emissions and other fugitive emissions. Other point source emissions account for natural gas emissions that are not accounted for elsewhere in model and can be recovered for flaring. Other fugitive emissions include emissions that are not accounted for elsewhere in the model and cannot be recovered for flaring.

EPA's Background Technical Support Document - Petroleum and Natural Gas Industry (EPA, 2011a) was used for quantifying the other point source and fugitive emissions from natural gas extraction and processing. A three-step process was used to filter EPA's venting and flaring data so that it is consistent with the boundary assumptions of this analysis:

1. Emissions that are accounted for by NETL's existing natural gas unit processes were not included in the categories for other point source and fugitive emissions. For example, EPA provides emission rates for well construction, well completion, dehydration, and pneumatic devices. The emissions from these activities are accounted for elsewhere in NETL's model and thus, to avoid double counting, are not included in the emission factors for other point and fugitive emissions.
2. Emissions that fall within NETL's boundary definitions for natural gas processing were moved from the natural gas extraction category to the natural gas processing category.
3. The EPA data (EPA, 2011a) does not discern between point source and fugitive emissions, so emissions were assigned to the point source or fugitive emission categories based on another EPA reference that provides more details on point source and fugitive emissions (Bylin, et al., 2010).

Other Point Source and Fugitive Emissions from Onshore Extraction

The data for other point source and fugitive emissions from onshore extraction are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from construction, dehydration, compressors, well completion, and pneumatic devices; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. Additionally, emissions from Kimray pumps, condensate tanks, and compressor blowdowns are re-categorized as natural gas *processing* emissions in NETL's model, and are thus not included in the emission factors for natural gas *extraction*. Based on EPA's data (EPA, 2011a) and NETL's boundary assumptions, the emission factors for point source and fugitive emissions from onshore gas extraction are 7.49E-05 lb CH_4/lb NG extracted and 1.02E-03 lb CH_4/lb NG extracted, respectively. The data for these calculations are shown in **Table A-6**.

Table A-6: Other Point Source and Fugitive Emissions from Onshore NG Extraction

Emission Source	Emissions (MMcf/year)	Location (UP)	Point Source	Fugitive
Normal Fugitives				
Gas Wells	2,751	Construction		
Heaters	1,463		1,463	
Separators	4,718			4,718
Dehydrators	1,297	Dehydrator		
Meters/Piping	4,556			4,556
Small Reciprocating Compressor	2,926	Reciprocating Compressor		
Large Reciprocating Compressor	664	Reciprocating Compressor		
Large Reciprocating Stations	45	Reciprocating Compressor		
Pipeline Leaks	8,087			8,087
Vented and Combusted				
Completion Flaring	0	Well Completion V&F		
Well Drilling	96	Well Completion		
Coal Bed Methane	3,467	Well Completion		
Pneumatic Device Vents	52,421	Pneumatic Devices		
Chemical Injection Pumps	2,814			2,814
Kimray Pumps	11,572	In NG processing boundary		
Dehydrator Vents	3,608	Dehydrator V&F		
Condensate Tanks without Control Devices	1,225	In NG processing boundary		
Condensate Tanks with Control Devices	245	In NG processing boundary		
Gas Engines, Compressor Exhaust Vented	11,680	Gas Compressor		
Well Workovers				
Well Workovers, Gas Wells	47	Well Workovers		
Well Workovers, Well Clean Ups (Low Pressure Gas Wells)	9,008	Well Workovers		
Blowdowns				
Blowdowns, Vessel	31		31	
Blowdowns, Pipeline	129			129
Blowdowns, Compressors	113	In NG processing boundary		
Blowdowns, Compressor Starts	253	In NG processing boundary		
Upsets				
Pressure Relief Valves	29			29
Mishaps	70			70
Total Emissions	123,315		1,494	20,403
Total NG Extracted	19,950,828			
Emission Rate (lb CH_4/lb NG extracted)			**7.49E-05**	**1.02E-03**

Other Venting and Fugitive Emissions from Offshore Extraction

The data for other point source and fugitive emissions from offshore extraction are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from drilling rigs, flares, centrifugal seals, glycol dehydrators, gas engines and turbines, and pneumatic pumps; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. Based on EPA's data (EPA, 2011a) and NETL's boundary assumptions, the emission factors for point source and fugitive emissions from offshore gas extraction are 3.90E-05 lb CH_4/lb NG extracted and 2.41E-04 lb CH_4/lb NG extracted, respectively. The data for these calculations are shown in **Table A-7.**

Table A-7: Other Point Source and Fugitive Emissions from Offshore NG Extraction

Emission Source	Emissions (MMcf/year)	Location (UP)	Point Source	Fugitive
Amine gas sweetening unit	0.2	AGR and CO_2 removal		
Boiler/heater/burner	0.8		0.80	
Diesel or gasoline engine	0.01		0.01	
Drilling Rig	3	Construction		
Flare	24	Venting and Flaring		
Centrifugal Seals	358	Centrifugal Compressor		
Connectors	0.8			0.80
Flanges	2.4			2.38
Open Ended Line	0.1			0.10
Other	44			44.0
Pump Fugitive	0.5			0.50
Valves	19			19.00
Glycol Dehydrator	25	Dehydrator		
Loading Operation	0.1			0.10
Separator	796			796
Mud Degassing	8.0		8.00	
Natural Gas Engines	191	Reciprocating compressor		
Natural Gas Turbines	3.0	Centrifugal compressor		
Pneumatic Pumps	7.0	Pneumatic Devices		
Pressure Level Controls	2.0			2.00
Storage Tanks	7.0		7.00	
Variable Exhaust Nozzle Exhaust Gas	124		124	
Total Emissions	1616		140	865
Total Processed NG	3,584,190			
Emission Rate (lb CH_4/lb NG extracted)			**3.90E-05**	**2.41E-04**

Other Venting and Fugitive Emissions from Natural Gas Processing

The data for other point source and fugitive emissions from natural gas processing are shown in the following table. These data are based on EPA data representative of 2006 natural gas production (EPA, 2011a). The original data (EPA, 2011a) include emissions from reciprocating compressors, centrifugal compressors, AGR units, dehydrators, and pneumatic devices; these processes are accounted for elsewhere in NETL's model and thus are not included in the emission factors for other point source and fugitive emissions. Based on EPA's data (EPA, 2011a) and NETL's boundary assumptions, the emission factors for point source and fugitive emissions from natural gas processing are 3.68E-04 lb CH_4/lb NG extracted and 8.25E-04 lb CH_4/lb NG extracted, respectively. The data for these calculations are shown in **Table A-8**.

Table A-8: Other Point Source and Fugitive Emissions from NG Processing

Emission Source	Emissions (MMcf/year)	Location (UP)	Point Source	Fugitive
Normal Fugitives				
Plants	1,634		3,104	
Recip Compressors	17,351	Reciprocating Compressor		
Centrifugal Compressors	5,837	Centrifugal Compressor		
Vented and Combusted (Normal Operations)				
Compressor Exhaust, Gas Engines	6,913	Reciprocating Compressor		
Compressor Exhaust, Gas Turbines	195	Centrifugal Compressor		
AGR Vents	643	AGR and CO_2 removal		
Kimray Pumps (Glycol Pump for Dehydrator)	177			11,749
Dehydrator Vents	1,088	Dehydrator venting & flaring		
Pneumatic Devices	93	Pneumatic Device		
Routine Maintenance				
Blowdowns/Venting	2,299		2,299	366
Total Emissions	36,230		5,403	12,115
Total Production	14,682,188			
Emissions Rate (lb CH_4/lb NG processed)			**3.68E-04**	**8.25E-04**

Natural Gas Compression

Compressors are used to increase the gas pressure for pipeline distribution. This analysis assumes that the inlet pressure to compressors at the natural gas extraction and processing site is 50 psig and the outlet pressure is 800 psig. The inlet pressure depends on the pressure of the natural gas reservoir and pressure drop during gas processing and thus introduces uncertainty to the model. The outlet pressure of 800 psig is a standard pressure for pipeline transport of natural gas.

The energy required for compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures). A two-stage compressor with an inlet pressure of 50 psig and an outlet pressure of 800 psig has a power requirement of 187 horsepower per MMcf of natural gas (GE Oil and Gas, 2005). Using a natural gas density of 0.042 lb/cf and converting to kilograms gives a compression energy intensity of 1.76E-04 MWh per kg of natural gas. This energy rate represents the required *output* of the compressor shaft; the *input* fuel requirements for compression vary according to compression technology. The two types of compressors used for natural gas operations are reciprocating compressors and centrifugal compressors. These two compressor types are discussed below.

Reciprocating compressors account for an estimated 75 percent of wellhead compression in the Barnett Shale gas play, and are estimated to accounted for all wellhead compression at conventional onshore, conventional onshore associated, and coal bed methane wells. Reciprocating compressors used for industrial applications are driven by a crankshaft that can be powered by 2- or 4-stroke diesel engines. Reciprocating compressors are not as efficient as centrifugal compressors and are typically used for small scale extraction operations that do not justify the increased capital requirements of centrifugal compressors. The natural gas fuel requirements for a gas-powered, reciprocating compressor used for natural gas extraction are based on a compressor survey conducted for natural gas production facilities in Texas (Houston Advanced Research Center, 2006). The average energy intensity of a gas-powered turbine is 8.74 Btu/hp-hr (Houston Advanced Research Center, 2006). Using a natural gas heating value of 1,027 Btu/cf (API, 2009), a natural gas density of 0.042 lb/cf (API, 2009), and converting to kilograms translates to 217 kg of natural gas per MWh of centrifugal, gas-powered turbine output. This fuel factor represents the mass of natural gas that is combusted per compressor energy output. The carbon dioxide emissions from a gas-powered, 4-stroke reciprocating compressor are 110 lb/MMBtu of fuel input. Similarly, the methane emissions from the same type of reciprocating compressor are 1.25 lb/MMBtu of fuel input (EPA, 1995); these methane emissions result from leaks in compressor rod packing systems and are based on measurements conducted by the EPA on a sample of 22 compressors (EPA, 1995).

The emissions for the operation of wellhead compressors are shown in **Table A-9** below.

Table A-9: Gas-Powered Reciprocating Compressor Operations

Air Emission Factors			
CO_2	110 lb/MMBtu fuel	0.047 kg/MJ fuel	EPA 1995
CH_4	1.25 lb/MMBtu fuel	5.37E-04 kg/MJ fuel	EPA 1995
Energy Inputs and Outputs			
Output shaft energy	7.39E-05 MWh/lb	1.63E-04 MWh/kg	GE 2005
Heat rate	478 lb NG/MWh	217 kg NG/MWh	HARC 2006
Fuel input	3.54E-02 lb NG/lb NG	3.54E-02 kg NG/kg NG	calculated
Air Emissions			
CO_2	0.095 lb/lb NG	0.095 kg/kg NG	calculated
CH_4	1.08E-03 lb/lb NG	1.08E-03 kg/kg NG	calculated

Gas powered centrifugal compressors are commonly used at offshore natural gas extraction sites. The amount of natural gas required for gas powered centrifugal compressor operations is based on manufacturer data that compares power requirements to compression ratios (the ratio of outlet to inlet pressures). A two-stage centrifugal compressor with an inlet pressure of 50 psig and an outlet pressure of 800 psig has a power requirement of 187 horsepower per MMcf of natural gas (GE Oil and Gas, 2005). Using a natural gas density of 0.042 lb/cf and converting to kilograms gives a compression energy intensity of 1.76E-04 MWh per kg of natural gas.

Table A-10: Gas-Powered Centrifugal Compressor Operations

Air Emission Factors			
CO_2	110 lb/MMBtu fuel	0.047 kg/MJ fuel	EPA 1995
CH_4	8.60E-03 lb/MMBtu fuel	3.70E-06 kg/MJ fuel	EPA 1995
N_2O	3.00E-03 lb/MMBtu fuel	1.29E-06 kg/MJ fuel	EPA 1995
Energy Inputs and Outputs			
Output shaft energy	7.39E-05 MWh/lb	1.63E-04 MWh/kg	GE 2005
Heat rate	443 lb NG/MWh	201 kg NG/MWh	API 2009
Fuel input	3.28E-02 lb NG/lb NG	3.28E-02 kg NG/kg NG	calculated
Air Emissions			
CO_2	0.088 lb/lb NG	0.088 kg/kg NG	calculated
CH_4	6.89E-06 lb/lb NG	6.89E-06 kg/kg NG	calculated
N_2O	2.40E-06 lb/lb NG	2.40E-06 kg/kg NG	calculated

Electrically-powered centrifugal compressors account for an estimated 25 percent of wellhead compression in the Barnett Shale gas play, but were not found to be utilized in substantial numbers outside of the Barnett Shale. If the natural gas extraction site is near a source of electricity, it has traditionally been financially preferable to use electrically-powered equipment instead of gas-powered equipment. This is the case for extraction sites for Barnett Shale located near Dallas-Fort Worth. The use of electric equipment is also an effective way of reducing the noise of extraction operations, which is encouraged when an extraction site is near a city.

An electric centrifugal compressor uses the same compression principles as a gas-powered centrifugal compressor, but its shaft energy is provided by an electric motor instead of a gas-fired turbine. The average power range of electrically-driven compressor in the U.S. natural gas transmission network is greater than 500 horsepower. This analysis assumes that compressors of this size have an efficiency of 95 percent (DOE, 1996). This efficiency is the ratio of mechanical power output to electrical power input. Thus, approximately 1.05 MWh of electricity is required per MWh of compressor energy output. The upstream emissions associated with the generation of electricity are modeled with the fuel mix of the Electric Reliability Council of Texas (ERCOT) grid, which is representative of electricity generation in Texas (the location of Barnett Shale). The air emissions from electricity generation are based on the 2005 fuel mix for the ERCOT region (Texas) and are modeled by NETL's LCA model for power generation. Electric compressors have negligible methane emissions because they do not require a fuel line for the combustion of product natural gas and incomplete combustion of natural gas is not an issue (EPA, 2011c). Electric compressors are also recommended by EPA's Natural Gas STAR program as a strategy for reducing system emissions of methane (EPA, 2011c).

Table A-11: Electrically-Powered Centrifugal Compressor Operations

Air Emissions from Electricity Generation			
CO_2	1,784 lb/MWh	809 kg/MWh	calculated
N_2O	2.29E-02 lb/MWh	1.04E-02 kg/MWh	calculated
CH_4	2.36 lb/MWh	1.07 kg/MWh	calculated
SF_6	2.23E-09 lb/MWh	1.01E-09 kg/MWh	calculated
Energy Inputs and Outputs			
Output shaft energy	7.39E-05 MWh/lb NG	1.63E-04 MWh/kg	GE 2005
Heat rate	1.053 MWh/MWh	1.053 MWh/MWh	API 2009
Electricity input	7.80E-05 MWh/lb NG	1.72E-04 MWh/kg NG	calculated
Air Emissions			
CO_2	0.139 lb/lb NG	0.139 kg/kg NG	calculated
N_2O	1.78E-06 lb/lb NG	1.78E-06 kg/kg NG	calculated
CH_4	1.84E-04 lb/lb NG	1.84E-04 kg/kg NG	calculated
SF_6	1.73E-13 lb/lb NG	1.73E-13 kg/kg NG	calculated

Well Decommissioning

This analysis assumes that the de-installation of a natural gas well incurs ten percent of the energy requirements and emissions as the original installation of the well.

Compilation of Natural Gas Processes

All energy and emissions data for the extraction of natural gas are described above. The compilation of these data into a model for natural gas extraction involves the connection of all unit processes into an interdependent network.

To model the extraction of natural gas from different sources (onshore, offshore, unconventional, etc.) it is necessary to tune each unit process within this network with a set of source-specific parameters. The assumptions used to adjust the unit processes into profiles of specific natural gas types are shown in **Table A-12**.

Table A-12: Natural Gas Modeling Parameters

Property	Units	Onshore	Associated	Offshore	Tight Sands	Barnett Shale	Coal Bed Methane
Natural Gas Source							
Contribution to 2009 Natural Gas Mix	Percent	23%	7%	13%	32%	16%	9%
2009 Production Rate	Mcf/day	65.6	121	2,795	110	273	104
Marginal Production Rate	Mcf/day	592	398	6,165	110	273	76.2
Natural Gas Extraction Well							
Flaring Rate at Extraction Well Location	Percent	51%	51%	51%	15%	15%	51%
Well Completion, Production Gas (prior to flaring)	Mcf/completion	47	47	47	4,657	11,643	63
Well Workover, Production Gas (prior to flaring)	Mcf/workover	3.1	3.1	3.1	4,657	11,643	63
Well Workover, Number per Well Lifetime	Workovers/well	1.1	1.1	1.1	3.5	3.5	3.5
Liquids Unloading, Production Gas (prior to flaring)	Mcf/episode	23.5	n/a	23.5	n/a	n/a	n/a
Liquids Unloading, Number per Well Lifetime	Episodes/well	930	n/a	930	n/a	n/a	n/a
Pneumatic Device Emissions, Fugitive	lb CH_4/Mcf	0.05	0.05	0.01	0.05	0.05	0.05
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/Mcf	0.003	0.003	0.002	0.003	0.003	0.003
Other Sources of Emissions, Fugitive	lb CH_4/Mcf	0.043	0.043	0.01	0.043	0.043	0.043
Natural Gas Processing Plant							
AGR and CO_2 Removal Unit							
Flaring Rate for AGR and CO_2 Removal Unit	Percent	100%	100%	100%	100%	100%	100%
Methane Absorbed into Amine Solution	lb CH_4/Mcf	0.04	0.04	0.04	0.04	0.04	0.04
Carbon Dioxide Absorbed into Amine Solution	lb CO_2/Mcf	0.56	0.56	0.56	0.56	0.56	0.56
Hydrogen Sulfide Absorbed into Amine Solution	lb H_2S/Mcf	0.21	0.21	0.21	0.21	0.21	0.21
NMVOC Absorbed into Amine Solution	lb NMVOC/Mcf	6.59	6.59	6.59	6.59	6.59	6.59
Glycol Dehydrator Unit							
Flaring Rate for Dehydrator Unit	Percent	100%	100%	100%	100%	100%	100%
Water Removed by Dehydrator Unit	lb H_2O/Mcf	0.045	0.045	0.045	0.045	0.045	0.045
Methane Emission Rate for Glycol Pump & Flash Separator	lb CH_4/Mcf	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
Pneumatic Devices and Other Sources of Emissions							
Flaring Rate for Other Sources of Emissions	Percent	100%	100%	100%	100%	100%	100%
Pneumatic Device Emissions, Fugitive	lb CH_4/Mcf	0.05	0.05	0.05	0.05	0.05	0.05
Other Sources of Emissions, Point Source (prior to flaring)	lb CH_4/Mcf	0.02	0.02	0.02	0.02	0.02	0.02
Other Sources of Emissions, Fugitive	lb CH_4/Mcf	0.03	0.03	0.03	0.03	0.03	0.03
Natural Gas Compression at Gas Plant							
Compressor, Gas-powered Combustion, Reciprocating	Percent	100%	100%		100%	75%	100%
Compressor, Gas-powered Turbine, Centrifugal	Percent			100%			
Compressor, Electrical, Centrifugal	Percent					25%	

Production Rates for Conventional Onshore Natural Gas Wells

The purpose of this discussion is to describe the data sources and calculations used to determine the typical production rate of conventional onshore natural gas wells. The population of conventional onshore wells is a lot more diverse that other types of natural gas wells, and thus it is necessary to distinguish between the large population of wells with low production rates and the relatively small population of wells with high production rates.

The Energy Information Administration (EIA) collects production data for oil and gas wells in the U.S. and organizes it according to production rates. The EIA data for total U.S. production is shown in **Table A-13**. The data in **Table A-13** are copied directly from EIA (EIA, 2010b) and show 22 production rate brackets. The lowest bracket includes wells that produce less than one barrel of oil equivalent (BOE) per day, and the highest bracket represents wells that produce more than 12,800 BOE per day. The EIA data have separate groups for oil wells and gas wells; from these data, we know that in 2009 the U.S. had 363,459 oil wells and 461,388 gas wells. These data also show the co-production of oil at gas wells as well as the average per well production rate within each production rate bracket.

The goal of this discussion is to focus on conventional onshore gas extraction. The data in **Table A-13** includes offshore production, and to develop a more accurate representation of onshore gas production, it is necessary to remove offshore data from the total U.S. profile. The EIA also has data for offshore production, as shown by **Table A-14**. By subtracting the offshore data from the total U.S. well profile, production data exclusive to onshore wells can be determined, as shown in **Table A-15**.

Table A-13: U.S. Total 2009 Distribution of Wells by Production Rate Bracket (EIA, 2010b)

Prod. Rate Bracket (BOE/Day)	Oil Wells							Gas Wells						
	# of Oil Wells	% of Oil Wells	Annual Oil Prod. (MMbbl)	% of Oil Prod.	Oil Rate per Well (bbl/Day)	Annual Gas Prod. (Bcf)	Gas Rate per Well (Mcf/Day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (Bcf)	% of Gas Prod.	Gas Rate per Well (Mcf/Day)	Annual Oil Prod. (MMbbl)	Oil Rate per Well (bbl/Day)
0-1	127,734	35.1	15.4	0.9	0.4	4.8	0.1	91,005	19.7	73.4	0.3	2.4	0.7	0.0
1-2	45,649	12.6	21.8	1.3	1.4	9.5	0.6	45,034	9.8	131.1	0.5	8.3	1.3	0.1
2-4	47,803	13.2	45.3	2.8	2.7	22.3	1.3	60,930	13.2	358.3	1.5	16.6	3.6	0.2
4-6	27,625	7.6	43.6	2.7	4.4	29.4	3.0	43,009	9.3	428.4	1.8	28.0	4.4	0.3
6-8	21,816	6.0	48.3	2.9	6.2	36.7	4.7	32,564	7.1	457.8	1.9	39.4	4.5	0.4
8-10	15,482	4.3	42.9	2.6	7.7	40.0	7.2	24,829	5.4	451.1	1.9	50.8	4.3	0.5
10-12	12,642	3.5	43.8	2.7	9.7	33.5	7.4	18,967	4.1	420.5	1.8	62.1	4.1	0.6
12-15	11,801	3.2	50.3	3.1	11.9	37.3	8.8	21,718	4.7	591.1	2.5	76.2	5.7	0.7
15-20	13,895	3.8	75.1	4.6	15.2	60.8	12.3	23,974	5.2	841.3	3.5	98.5	7.7	0.9
20-25	8,157	2.2	56.6	3.4	19.6	46.2	16.1	16,539	3.6	744.2	3.1	126.5	7.5	1.3
25-30	6,276	1.7	52.3	3.2	23.7	46.5	21.1	11,638	2.5	644.9	2.7	156.7	5.1	1.2
30-40	7,207	2.0	75.3	4.6	30.0	69.0	27.5	16,083	3.5	1,122.3	4.7	197.4	9.5	1.7
40-50	3,684	1.0	49.0	3.0	39.1	42.1	33.5	9,959	2.2	895.6	3.7	255.6	7.1	2.0
50-100	7,934	2.2	159.7	9.7	59.4	171.4	63.7	22,546	4.9	3,156.6	13.2	402.7	22.4	2.9
100-200	3,070	0.8	119.1	7.3	118.3	115.9	115.1	13,444	2.9	3,520.4	14.7	782.4	30.8	6.8
200-400	1,469	0.4	109.9	6.7	233.9	122.3	260.3	5,528	1.2	2,572.2	10.7	1,545.1	22.3	13.4
400-800	663	0.2	92.3	5.6	447.9	128.5	623.6	2,038	0.4	1,708.3	7.1	3,007.9	22.2	39.0
800-1,600	264	0.1	77.8	4.7	900.8	114.4	1,325.0	816	0.2	1,342.4	5.6	6,039.3	25.0	112.6
1,600-3,200	145	0.0	86.8	5.3	1,770.4	121.8	2,485.6	460	0.1	1,633.2	6.8	11,907.5	35.8	261.0
3,200-6,400	66	0.0	88.1	5.4	3,950.0	92.9	4,167.6	247	0.1	1,913.3	8.0	22,917.6	46.1	552.0
6,400-12,800	47	0.0	112.4	6.8	7,428.9	132.1	8,729.2	51	0.0	725.3	3.0	46,468.5	9.9	635.0
> 12,800	30	0.0	176.5	10.7	18,162.2	136.8	14,083.1	9	0.0	227.5	0.9	84,081.9	3.3	1,204.3
Total	**363,459**	**100.0**	**1,642.3**	**100.0**	**12.9**	**1,614.4**	**12.7**	**461,388**	**100.0**	**23,959.1**	**100.0**	**148.5**	**283.2**	**1.8**

Table A-14: Federal Gulf 2009 Distribution of Wells by Production Rate Bracket (EIA, 2010a)

Prod. Rate Bracket (BOE/Day)	Oil Wells							Gas Wells						
	# of Oil Wells	% of Oil Wells	Annual Oil Prod. (Mbbl)	% of Oil Prod.	Oil Rate per Well (bbl/Day)	Annual Gas Prod. (MMcf)	Gas Rate per Well (Mcf/Day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (MMcf)	% of Gas Prod.	Gas Rate per Well (Mcf/Day)	Annual Oil Prod. (Mbbl)	Oil Rate per Well (bbl/Day)
0-1	46	1.5	3.1	0.0	0.3	4.8	0.4	116	4.4	52.2	0.0	1.9	0.7	0.0
1-2	23	0.8	6.5	0.0	1.2	10.2	1.9	55	2.1	112.1	0.0	8.2	1.7	0.1
2-4	40	1.3	30.4	0.0	2.5	43.0	3.5	70	2.7	278.2	0.0	15.8	4.2	0.2
4-6	37	1.2	41.6	0.0	4.0	71.0	6.8	74	2.8	538.6	0.0	27.4	8.1	0.4
6-8	43	1.4	66.9	0.0	5.4	108.4	8.8	51	1.9	499.7	0.0	37.8	8.2	0.6
8-10	46	1.5	101.6	0.0	7.0	169.0	11.7	43	1.6	609.0	0.0	50.0	6.4	0.5
10-12	32	1.1	89.2	0.0	9.2	111.5	11.5	35	1.3	547.3	0.0	56.6	14.5	1.5
12-15	65	2.2	229.0	0.0	11.3	267.8	13.2	51	1.9	1,041.6	0.1	69.9	28.1	1.9
15-20	99	3.3	448.9	0.1	14.1	676.8	21.2	89	3.4	2,557.3	0.1	93.8	43.2	1.6
20-25	101	3.4	625.5	0.1	18.6	792.3	23.5	84	3.2	3,023.3	0.2	121.1	56.3	2.3
25-30	111	3.7	856.6	0.2	23.1	937.8	25.3	77	2.9	3,140.6	0.2	146.8	59.5	2.8
30-40	216	7.2	2,107.2	0.4	28.5	2,821.7	38.2	126	4.8	7,456.0	0.4	191.8	109.5	2.8
40-50	189	6.3	2,403.6	0.4	37.1	2,952.2	45.6	108	4.1	7,788.0	0.4	240.3	175.6	5.4
50-100	638	21.3	13,471.4	2.5	60.5	16,722.2	75.1	351	13.3	42,876.5	2.3	394.8	718.7	6.6
100-200	506	16.9	21,060.9	3.9	118.8	23,817.1	134.4	388	14.7	99,838.2	5.3	815.0	1,272.4	10.4
200-400	303	10.1	23,902.4	4.4	234.2	27,232.1	266.9	357	13.5	171,637.2	9.1	1,587.1	2,113.7	19.5
400-800	157	5.2	24,319.8	4.5	465.6	28,928.2	553.8	281	10.6	267,687.1	14.2	3,139.7	3,352.2	39.3
800-1,600	124	4.1	37,018.6	6.8	911.9	51,361.6	1,265.2	155	5.9	297,842.7	15.8	6,179.4	5,209.8	108.1
1,600-3,200	86	2.9	53,804.6	9.9	1,901.4	73,151.5	2,585.1	72	2.7	281,825.9	15.0	12,283.7	5,179.9	225.8
3,200-6,400	58	1.9	79,016.7	14.5	4,001.7	81,878.3	4,146.6	34	1.3	259,606.8	13.8	24,584.0	4,941.2	467.9
6,400-12,800	45	1.5	107,626.0	19.8	7,472.5	126,500.1	8,782.9	16	0.6	234,073.5	12.4	53,797.6	909.8	209.1
> 12,800	30	1.0	176,482.4	32.5	18,162.2	136,845.3	14,083.1	8	0.3	200,795.6	10.7	85,773.4	2,324.5	992.9
Total	**2,995**	**100.0**	**543,712.9**	**100.0**	**541.3**	**575,403.0**	**572.8**	**2,641**	**100.0**	**1,883,827.2**	**100.0**	**2,396.7**	**26,538.1**	**33.8**

Table A-15: U.S. 2009 Distribution of Onshore Gas Wells (EIA, 2010a, 2010b)

Prod. Rate Bracket (BOE/day)	# of Gas Wells	% of Gas Wells	Annual Gas Prod. (Bcf)	% of Gas Prod.	Gas Rate per Well (Mcf/day)	Annual Oil Prod. (MMbbl)	Oil Rate per Well (bbl/day)	Gas Energy Equivalent (MMBtu/day)	Oil Energy Equivalent (MMBtu/day)	% of Energy from Gas	Adjusted Gas Rate per Well, (Mcf/Day)[1]
0-1	90,889	19.8%	73.4	0.3%	2.2	0.7	0.0	2.3	0.1	94.9%	2.3
1-2	44,979	9.8%	131.0	0.6%	8.0	1.3	0.1	8.2	0.5	94.7%	8.4
2-4	60,860	13.3%	358.0	1.6%	16.1	3.6	0.2	16.6	0.9	94.6%	17.0
4-6	42,935	9.4%	427.9	1.9%	27.3	4.4	0.3	28.0	1.6	94.5%	29.0
6-8	32,513	7.1%	457.3	2.1%	38.5	4.5	0.4	39.6	2.2	94.7%	41.0
8-10	24,786	5.4%	450.5	2.0%	49.8	4.3	0.5	51.1	2.8	94.9%	52.0
10-12	18,932	4.1%	420.0	1.9%	60.8	4.1	0.6	62.4	3.4	94.8%	64.0
12-15	21,667	4.7%	590.1	2.7%	74.6	5.7	0.7	76.6	4.2	94.9%	79.0
15-20	23,885	5.2%	838.7	3.8%	96.2	7.7	0.9	98.8	5.1	95.1%	101.0
20-25	16,455	3.6%	741.2	3.4%	123.0	7.4	1.2	127.0	7.0	94.6%	130.0
25-30	11,561	2.5%	641.8	2.9%	152.0	5.0	1.2	156.0	7.0	95.8%	159.0
30-40	15,957	3.5%	1,114.8	5.1%	191.0	9.4	1.6	197.0	9.0	95.5%	201.0
40-50	9,851	2.1%	887.8	4.0%	247.0	6.9	1.9	254.0	11.0	95.8%	258.0
50-100	22,195	4.8%	3,113.7	14.1%	384.0	21.7	2.7	395.0	16.0	96.2%	399.0
100-200	13,056	2.8%	3,420.6	15.5%	718.0	29.5	6.2	737.0	36.0	95.4%	753.0
200-400	5,171	1.1%	2,400.6	10.9%	1,272.0	20.2	10.7	1,306.0	62.0	95.5%	1,332.0
400-800	1,757	0.4%	1,440.6	6.5%	2,246.0	18.9	29.4	2,307.0	170.0	93.1%	2,412.0
800-1,600	661	0.1%	1,044.6	4.7%	4,330.0	19.8	82.0	4,446.0	476.0	90.3%	4,793.0
1,600-3,200	388	0.1%	1,351.4	6.1%	9,542.0	30.6	216.0	9,800.0	1,254.0	88.7%	10,763.0
3,200-6,400	213	0.0%	1,653.7	7.5%	21,271.0	41.2	529.0	21,845.0	3,071.0	87.7%	24,261.0
6,400-12,800	35	0.0%	491.2	2.2%	38,452.0	9.0	704.0	39,490.0	4,082.0	90.6%	42,427.0
> 12,800	1	0.0%	26.7	0.1%	73,163.0	1.0	2,673.0	75,138.0	15,501.0	82.9%	88,256.0
Total	**458,747**	**100.0%**	**22,075.4**	**100.0%**	**132.0**	**256.8**	**1.5**	**135.0**	**8.9**	**93.8%**	**140.0**

[1] Adjusted by energy-based co-product allocation

Co-product Allocation of Oil

The EIA data also shows that gas wells produce a small share of oil. On an energy basis, oil comprises approximately 3.8 to 17 percent of gas well production, depending on the production rate bracket. Using energy-based, co-product allocation, it is necessary to scale the production rates of the gas wells so they are representative of 100 percent gas production.

For example, a gas well that has daily production rates of 718 Mcf of natural gas and 6.2 barrels of oil has a total daily production of 773 MMBtu of energy. This energy equivalency is calculated using heating values of 1,027 Btu/cf for natural gas and 5.8 MMBtu/bbl for oil. If expressed solely on and energy-equivalent basis of natural gas, 773 MMBtu of energy is equal to 753 Mcf of natural gas. Thus, in this instance, accounting for the co-production of oil increases the nominal production rate of the gas well from 718 Mcf/day to 752 Mcf/day. Note that this nominal rate of 752 Mcf/day does not represent the actual gas produced by the well, but is an LCA accounting method that uses the relative energies of produced oil and natural gas to scale the gas production rate so it is representative of a well that produces only natural gas.

Selection of Representative Production Brackets

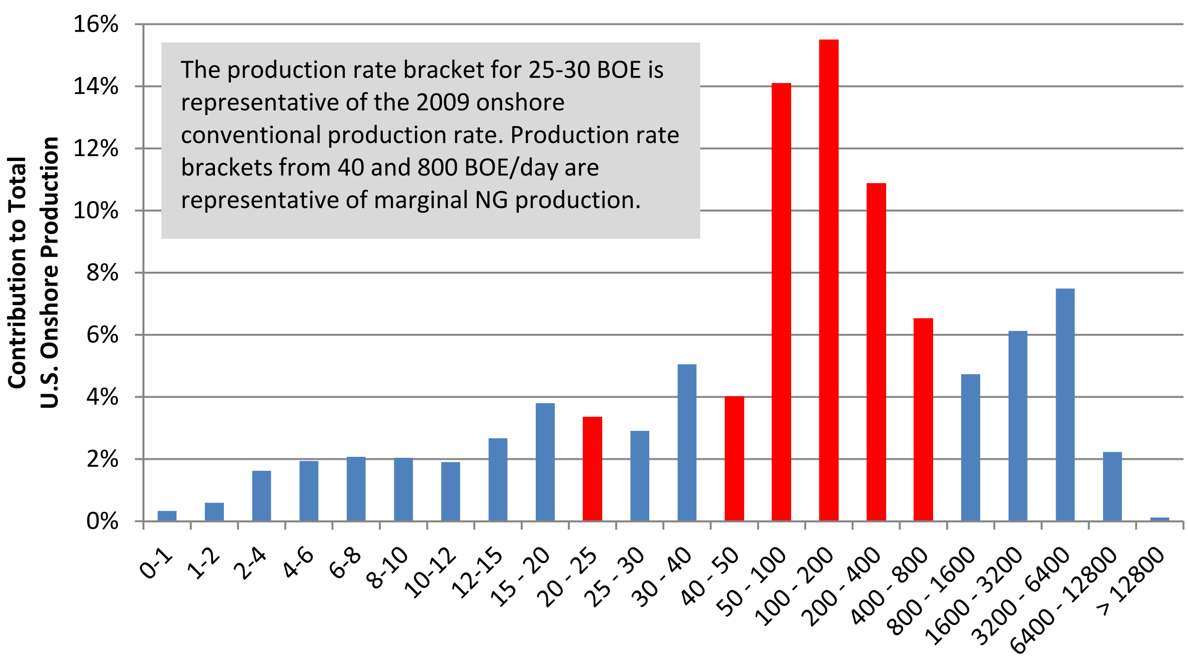
The production rates of onshore conventional natural gas wells vary widely and are a function of reservoir properties, extraction technology, and age. As shown by the EIA data, the production rates of onshore gas wells range from less than 1 BOE/day to more than 12,800 BOE/day. There are not enough data to determine the split between conventional and unconventional wells within each production rate bracket; however, the total production of each bracket and the production rates of unconventional wells can be used to determine the most likely production rates for onshore conventional natural gas. The distribution of gas wells by total gas produced is shown in **Figure A-2**

The production categories in **Table A-15** include a large population of wells in the lowest production rate bracket; 19.8 percent of U.S. onshore natural gas wells produce less than one BOE per day. Similarly, the production rate bracket for 1 - 2 BOE/day includes 9.8 percent of natural gas wells, the production rate bracket for 2 - 4 BOE/day includes 13.3 percent of natural gas wells, and the production rate bracket for 4 - 6 BOE/day includes 9.4 percent of natural gas wells. While these four production rate brackets account for 52 percent of the total count of natural gas wells, they account for only 4.5 percent of total natural gas production.

The average production rate for conventional onshore natural gas wells in 2009 was 66 Mcf per day. This production rate was calculated by dividing the amount of onshore conventional natural gas that was produced in 2009 by the total number of onshore conventional natural gas wells in 2009.

The marginal production rate for conventional onshore natural gas was calculated by selecting the most productive region of the production rate brackets. The production rate brackets that include 40 to 800 BOE/day represent 51 percent of total onshore natural gas production. The average production rate of this range of wells is 592 Mcf/day.

Figure A-2: Distribution of Onshore Natural Gas Wells



A.2 Raw Material Acquisition: Coal

Raw material extraction for coal incorporates extraction profiles for coal derived from the PRB, where sub-bituminous, low-rank coal extracted from thick coal seams (up to approximately 180 feet) via surface mines located in Montana and Wyoming, and coal derived from the Illinois No. 6 coal seam, where bituminous coal is extracted from approximately 2 to 15 foot seams via underground longwall and continuous mining. Each modeling approach is described below.

Powder River Basin Coal

The PRB coal-producing region consists of counties in two states – Big Horn, Custer, Powder River, Rosebud, and Treasure in Montana, and Campbell, Converse, Crook, Johnson, Natrona, Niobrara, Sheridan, and Weston in Wyoming (EIA, 2009). PRB coal is advantageous in comparison to bituminous coals in that it has lower ash and sulfur content. However, PRB coal also has a lower heating value than higher rank coals (Clyde Bergemann, 2005). In 2007, there were 17 surface mines extracting PRB coal, which produced over 479 million short tons (EIA, 2009).

PRB coal is modeled using modern mining methods in practice at the following mines: Peabody Energy's North Antelope-Rochelle mine (97.5 million short tons produced in 2008), Arch Coal, Inc.'s Black Thunder Mine (88.5 million short tons produced in 2008), Rio Tinto Energy America's Jacobs Ranch (42.1 million short tons produced in 2008), and Cordero Rojo Operation (40.0 million short tons produced in 2008). These four mines were the largest surface mines in the United States in 2008 according to the National Mining Association's 2008 Coal Producer Survey (National Mining Association, 2009).

Equipment and Mine Site

Much of the equipment utilized for surface coal mining in the PRB is very large. GHG emissions that result from the production of construction materials required for coal extraction were quantified for the following equipment, within the model: track loader (10 pieces at 26,373 kg each); rotary drill (3 pieces at 113,400 kg each); walking dragline (3 pieces at 7,146,468 kg each); electric mining shovel (10 pieces at 1,256,728 kg each); mining truck (11 pieces at 278,690 kg each); coal crusher (1 piece at 115,212 kg); conveyor (1 piece at 1,064,000 kg); and loading silo (6 pieces at 10,909,569 kg each).

Coal seams are located relatively close to the ground surface in the PRB such that large-scale surface mining is common. The coal seam ranges in thickness from 42 to 184 feet thick (EPA, 2004a). Before overburden drilling and cast blasting can be carried out, topsoil and unconsolidated overburden must be removed from the consolidated overburden that is to be blasted. These operations use both truck and shovel operations and bulldozing to move these materials to a nearby stockpile location so that they can be used in post-mining site reclamation. Estimates are made for topsoil/overburden operations based on requirements reported in the Energy and Environmental Profile of the U.S. Mining Industry (DOE, 2002) for a hypothetical western surface coal mine.

Overburden Blasting and Removal

Blast holes are drilled into overburden for subsequent ammonium nitrate and fuel oil packing and detonation using large rotary drills. Drills use electricity to drill 220-270 millimeter diameter holes through sandstone, siltstone, mudstone and carbonaceous shale that make up the overburden. Typically this overburden contains water, which controls particulate emission associated with drilling activities. For the purposes of this assessment it is assumed that drilling operations produce no direct emissions. Electricity requirements for drilling are taken from the U.S. DOE report Mining Industry for the Future: Energy and Environmental Profile of the U.S. Mining Industry (DOE, 2002).

Cast blasting is a blasting technique that was developed relatively recently, and has found broad application in large surface mines. Cast blasting comminutes (breaks into fragments/particles) overburden, and also moves an estimated 25-35 percent (modeled at 30 percent) of the blasted overburden to the target fill location (Mining Technology, 2007). The model assumes that blasting uses ammonium nitrate and fuel oil explosives with a powder factor[1] of 300 g per m^3 of overburden blasted (SME, 1990), and GHG emissions associated with explosive production and the blasting process are included in the model, based on EPA's AP-42 report (EPA, 1995).

Overburden removal is achieved primarily through dragline operations, with the remainder moved using large electric shovels. Dragline excavation systems are among the largest on-land machines, and utilize a large bucket suspended from a boom, where the bucket is scraped along the ground to fill the bucket. The bucket is then emptied at a nearby fill location. Electricity requirements for dragline operation combined with other on site operations, were estimated based on electricity usage at the North Antelope Rochelle Mine, to be approximately 971 kWh per 1000 tons of coal (Peabody, 2006). During this time dragline operation accounted for approximately 50% of the overburden energy.

[1] Powder factor refers to the mass of explosive needed to blast a given mass of material.

Coal Recovery

Following overburden removal, coal is extracted using truck and shovel-type operations. Because of the large scale of operations, large electric mining shovels (Bucyrus 495 High Performance Series) are assumed to be employed, with a bucket capacity of 120 tons, alongside 320-400 ton capacity mining trucks (Bucyrus International Inc., 2008).

The amount of coal that could be moved by a single shovel per year was determined by using data for the Black Thunder and Cordero Rojo coal mines (Mining Technology, 2007). A coal hauling distance of two miles is assumed, with a round-trip distance of four miles, based on evaluation of satellite imagery of mining operations. The extracted coal is ground and crushed to the necessary size for transportation. It is assumed that the coal does not require cleaning before leaving the mine site. The crushed coal is carried from the preparation facility to a loading silo by an overland conveyor belt. From the loading silo, the coal is loaded into railcars for transportation.

Coal Bed Methane Emissions

During coal acquisition, methane is released during both the coal extraction and post-mining coal preparation activities. While the PRB has relatively low specific methane content, the large thickness of the coal deposit (80 feet thick or more in many areas) has a large methane content per square foot of surface area. As a result the PRB has recently begun to be exploited on a large scale. Extraction of coal bed methane, prior to mining of the coal seam, results in a net reduction of the total amount of coal bed methane that is emitted to the atmosphere, since extracted methane is typically sold into the natural gas market, and eventually combusted.

For the purposes of this assessment, it is assumed that the coal seam in the area of active mining was previously drilled to extract methane. Based on recent data available from the EPA, coal bed methane emissions for surface mining, including the PRB, are expected to range from 8 to 98 standard cubic feet per ton (cf/ton) of produced coal, with a typical value of 51 cf/ton (EPA, 2011b).

Illinois No. 6 Coal

Illinois No. 6 coal is part of the Herrin Coal, and is a bituminous coal that is found in seams that typically range from about 2 to 15 feet in thickness, and is found in the southern and eastern regions of Illinois and surrounding areas. Illinois No. 6 coal is commonly extracted via underground mining techniques, including continuous mining and longwall mining. Illinois No. 6 coal seams may contain relatively high levels of mineral sediments or other materials, and therefore require coal cleaning (beneficiation) at the mine site. The following sections describe the unit processes modeled for Illinois No. 6 coal mining.

Equipment and Mine Site

Extraction of Illinois No. 6 coal requires several types of major equipment and mining components, in order to operate the coal mine. The following components were modeled for use during underground mining operations: site paving and concrete, conveyor belt, stacker/reclaimer, crusher, coal cleaning, silo, wastewater treatment, continuous miner, longwall mining systems (including shear head, roof supports, armored force conveyor, stage loader, and mobile belt tailpiece), and shuttle car systems with replacement. Overall, when considering materials requirements for the construction of these systems, the material inputs values shown in **Table A-16** were required for mine and mining system construction, on a per lb of coal output basis. GHG emissions associated with the production of these materials were incorporated into the model and accounted for as construction related emissions.

Table A-16: Construction Materials Required for Illinois No. 6 Coal Mining

Construction Material	Amount	Units
Cold-Rolled Steel	1.47E-05	lb/lb coal produced
Hot-dip Galvanized Steel	1.52E-06	lb/lb coal produced
Rubber	4.45E-07	lb/lb coal produced
Steel Plate	1.80E-04	lb/lb coal produced
Concrete	6.06E-05	lb/lb coal produced
Rebar	1.41E-06	lb/lb coal produced
Polyvinylchloride Pipe	1.30E-07	lb/lb coal produced
Steel, Stainless, 316	6.77E-08	lb/lb coal produced
Stainless Steel Cold Roll 431	6.77E-08	lb/lb coal produced
Cast Iron	3.38E-07	lb/lb coal produced
Copper Mix	8.11E-09	lb/lb coal produced
Asphalt	1.11E-03	lb/lb coal produced

Coal Mine Operations

Operations of the coal mine were based on operation of the Galatia Mine, which is operated by the American Coal Company and located in Saline County, Illinois. Sources reviewed in support of coal mine operations include Galatia Mine production rates, electricity usage, particulate emissions, methane emissions, wastewater discharge permit monitoring reports, and communications with Galatia Mine staff. When data from the Galatia Mine were not available, surrogate data were taken from other underground mines, as relevant.

Electricity is the main source of energy for coal mine operations. Electricity use for this model was estimated based on previous estimates made by EPA for electricity use for underground mining and coal cleaning at the Galatia Mine (EPA, 2008). The life cycle profile for electricity use is based on eGRID2007. The Emissions and Generation Resource Integrated Database (eGRID) is a comprehensive inventory of environmental attributes for electric power systems (EPA, 2010).

Although no Galatia Mine data were found that estimated the diesel fuel used during mining operations, it was assumed that some diesel would be used to operate trucks for moving materials, workers, and other secondary on-site operations. Therefore, diesel use was estimated for the Galatia Mine from 2002 U.S. Census data for bituminous coal underground mining operations and associated cleaning operations (U.S. Census Bureau, 2004). Emissions of GHGs were based on emissions associated with the use of diesel. EPA Tier 4 diesel standards for non-road diesel engines were used, since these standards would go into effect within a couple years of commissioning of the mine for this study (EPA, 2004b).

Coal Bed Methane

During the acquisition of Illinois No. 6 coal, methane is released during both the underground coal extraction and the post-mining coal preparation activities. Illinois No. 6 coal seams are not nearly as thick as PRB coals, and as a result are less commonly utilized as a resource for coal bed methane extraction. Instead, methane capture may be applied during the coal extraction process. Based on recent data available from the EPA, coal bed methane emissions for underground mining, including mining within the Illinois No. 6 coal seam, are expected to range from 360 to 500 cf/ton of produced coal, with a nominal value of 422 cf/ton (EPA, 2011b). It is assumed that no methane capture is applied for Illinois No. 6 coal.

A.3 Raw Material Transport: Natural Gas

The boundary of raw material transport begins with receipt of processed natural gas at the extraction site and ends with the delivery of natural gas to an energy conversion facility. Methane emissions from pipeline operations are a function of pipeline distance. This analysis uses a pipeline transport distance of 604 miles (971.4 km), which is the average distance for natural gas pipeline transmission in the U.S. The data sources and assumptions for calculating the greenhouse gas emissions from construction and operation of natural gas transmission pipelines are discussed below.

Pipeline Construction and Decommissioning

Carbon steel is the primary material used in the construction of natural gas pipelines. The mass of pipeline per unit length was determined using an online calculator (Steel Pipes & Tubes, 2009). The weight of valves and fittings were estimated at an additional 10 percent of the total pipeline weight. The pipeline was assumed to have a life of 30 years. The mass of pipeline construction per kilogram of natural gas was determined by dividing the total pipeline weight by the total natural gas flow through the pipeline for a 30-year period.

The decommissioning of a natural gas pipeline involves cleaning and capping activities. This analysis assumes that the decommissioning of a natural gas pipeline incurs 10 percent of the energy requirements and emissions as the original installation of the pipeline.

Pipeline Operations

The U.S. has an extensive natural gas pipeline network that connects natural gas supplies and markets. Compressor stations are necessary every 50 to 100 miles along the natural gas transmission pipelines in order to boost the pressure of the natural gas. Compressor stations consist of centrifugal and reciprocating compressors. Most natural gas compressors are powered by natural gas, but, when electricity is available, electrically-powered compressors are used.

A 2008 paper published by the Interstate Natural Gas Association of America provides data from its 2004 database, which shows that the U.S. pipeline transmission network has 5,400 reciprocating compressors and over 1,000 gas turbine compressors (Hedman, 2008). Further, based on written communication from El Paso Pipeline Group, approximately three percent of transmission compressors are electrically driven (El Paso Pipeline Group, 2011). El Paso Pipeline Group has the highest transmission capacity of all natural gas pipeline companies in the U.S., and it is thus assumed that the share of electrically-powered compressors in their fleet is representative of the entire natural gas transmission network. Based on written communication with El Paso Pipeline Group (El Paso Pipeline Group, 2011), the share of compressors on the U.S. natural gas pipeline transmission network is approximately 78 percent reciprocating compressors, 19 percent turbine-powered centrifugal compressors, and 3 percent electrically-powered compressors.

The use rate of natural gas for fuel in transmission compressors was calculated from the Federal Energy Regulatory Commission (FERC) Form 2 database, which is based on an annual survey of gas producers and pipeline companies (FERC, 2010). The 28 largest pipeline companies were pulled from the FERC Form 2 database. These 28 companies represent 81 percent of NG transmission in 2008. The FERC data for 81 percent of U.S. natural gas transmission is assumed to be a representative sample of the fuel use rate of the entire transmission network. This data shows that

0.96 percent of natural gas product is consumed as compressor fuel. This fuel use rate was converted to a basis of kg of natural gas consumed per kg of natural gas transported by multiplying it by the total natural gas delivered by the transmission network in 2008 (EIA, 2011) and dividing it by the annual tonne-km of pipeline transmission in the U.S. (Dennis, 2005). The total delivery of natural gas in 2008 was 21 Tcf, which is approximately 400 billion kg of natural gas. The annual transport rate for natural gas transmission was steady from 1995 through 2003, at approximately 380 billion tonne-km per year. More recent transportation data are not available, and thus this analysis assumes the same tonne-km rate for 2008 as shown from 1995 through 2003.

The air emissions from the combustion of natural gas by compressors are estimated by applying EPA emission factors to the natural gas consumption rate of the compressors (EPA, 1995). Specifically, the emission profile of gas-powered, centrifugal compressors is based on emission factors for gas turbines; the emission profile of gas-powered, reciprocating compressors is based on emission factors for 4-stroke, lean burn engines. For electrically-powered compressors, this analysis assumes that the indirect emissions are representative of the U.S. average fuel mix for electricity generation.

The average power of electrically-driven compressors for U.S. NG transmission is assumed to be the same as the average power of all compressors on the transmission network. An average compressor on the U.S. natural gas transmission network has a power rating of 14,055 horsepower (10.5 MW) and a throughput of 734 million cubic feet of natural gas per day (583,000 kg NG/hour) (EIA, 2007). Electrically-driven compressors have efficiencies of 95 percent (DOE, 1996; Hedman, 2008). This efficiency is the ratio of mechanical power output to electrical power input. Thus, approximately 1.05 MWh of electricity is required per MWh of compressor energy output.

In addition to air emissions from combustion processes, fugitive venting from pipeline equipment results in the methane emissions to air. The fugitive emission rate for natural gas pipeline operations is based on data published by the Bureau of Transportation Statistics (BTS) and EPA. The transport data for natural gas transmission is based on ton-mileage estimates by BTS, which calculates 253 billion ton-miles of natural gas transmission in 2003 (Dennis, 2005). The 2003 data are the most recent data point in the BTS reference, and thus EPA's inventory data for the years 2000 and 2005 were interpolated to arrive at a year 2003 value of 1,985 million kg of fugitive methane emissions per year (EPA, 2011b). Dividing the EPA emission by the transport requirements and converting to metric units gives 5.37E-06 kg/kg-km.

Calculation of Average Natural Gas Transmission Distance

The average pipeline distance for natural gas transport is determined by balancing national emission inventory (EPA, 2011b) and natural gas consumption data (EIA, 2011) with NETL's unit process emission factor for fugitive methane emissions from pipeline operations. **Equation 5** shows the national inventory and consumption data on the left-hand side and NETL's emission factor for fugitive methane on the right-hand side.

$$\frac{E_{methane}}{NG_{consumption}} = d * EF_{methane} \qquad \textbf{(Equation 5)}$$

Where,

$E_{methane}$ = Total pipeline fugitive methane emissions (default = 2,115E+06 kg CH_4/yr)
$NG_{consumption}$ = consumption of natural gas (default = 21.84 MMBtu/yr)
$EF_{methane}$ = Emission factor for fugitive methane (default =9.97E-05 kg CH_4/MMBtu-km)

The default value for total fugitive emissions of methane from pipeline transmission are based on the 2009 national inventory emissions for natural gas transmission and storage reported by EPA (EPA, 2011b). The value reported by EPA is 2,115 Gg CH_4/yr, which is equal to 2,115 million kg CH_4/yr.

The default value for annual natural gas consumption is based on annual EIA statistics for natural gas production and consumption (EIA, 2011). The volume of natural gas transported by pipeline is 21.26 Tcf/year. This value is the midpoint of the volume of processed natural gas injected to the pipeline transmission network and the volume of natural gas delivered to consumers. In 2009 the volume of natural gas injected to the natural gas transmission network by NG processing plants was 21.56 Tcf; this volume was calculated by subtracting the natural gas consumption at the extraction and processing sites (1.28 Tcf) from total annual consumption (22.84 Tcf) (EIA, 2011). In 2009 the volume of natural gas delivered to consumers was 20.97 Tcf (EIA, 2011). The average volume of natural gas transmission was converted to an energy basis using an energy density of 1,027 Btu/cf; 21.26 Tcf/year is equivalent to 21.84 E+09 MMBtu. Converting to an energy basis (using a density of 0.042 lbs/cf and energy content of 1,027 Btu/cf) gives 21.84 billion MMBtu.

For **Equation 5** it is necessary to convert the emission factor for fugitive emissions from pipeline operations (calculated above) to an energy basis so that it can be factored with the annual consumption data for natural gas. The emission factor used by the pipeline unit process is 5.37E-06 kg/kg-km. Converting to an energy basis (using the conversion factors of 0.042 lb/cf NG and 1,027 Btu/cf) results in an emission factor of 9.97E-05 kg CH_4/MMBtu-km.

The unknown *d* in **Equation 5** is the distance (km) that reconciles NETL's unit process with the national level data. Solving for *d* gives the following equation:

$$d = \frac{E_{methane}}{NG_{consumption} * EF_{methane}} \quad \textbf{(Equation 6)}$$

Applying the default values to **Equation 6** gives a distance of 971 km (604 miles), as shown in **Equation 7**.

$$d = \frac{2{,}115\times10^{6} kg\ CH_4/yr}{(21.84\times10^{9} MMBtu/yr)(9.97\times10^{-5} kgCH_4/MMBtu\ km)} = 971\ km \quad \textbf{(Equation 7)}$$

The pipeline transport of natural gas results in losses of natural gas product to two activities: (1) fugitive emissions and (2) natural gas used as fuel in pipeline compressors. Based on the data and assumptions of this unit process, the transmission of natural gas a distance of 971 km results in a 1.45 percent loss of natural gas product (1.0148 kg of natural gas are injected into the pipeline to deliver 1.0 kg of natural gas to the consumer). The annual data for natural gas production and consumption (EIA, 2011) show a 2.81 percent loss of natural gas for transmission and distribution (natural gas processing plants produce 21.56 Tcf of natural gas and 20.97 Tcf of natural gas are delivered to consumers). The 2.81 percentage loss factor includes pipeline *distribution* in addition to pipeline transmission, and thus it is expected for the transmission losses (1.45 percent) to be lower than the transmission and distribution loss (2.81 percent).

The default values for key variables for NETL's model of natural gas pipeline transmission are shown in the **Table A-17**.

Table A-17: Natural Gas Transport to Large End User

Natural Gas Emissions and Transmission Infrastructure	Units	Value
Pipeline Transport Distance (national average)	Miles	604
Distance Between Compressor Stations	Miles	75
Compression, Gas-powered, Reciprocating Engine	Percent	78%
Compression, Gas-powered, Centrifugal Engine	Percent	19%
Compression, Electrical, Centrifugal Engine	Percent	3%

A.4 Raw Material Transport: Coal

Train transport was modeled for the transport of both PRB and Illinois No. 6 coal from mining sites to energy conversion facilities. Mined coal is presumed to be transported by rail from PRB and Illinois No. 6 coal mine sources, in support of electricity production. Coal is assumed to be transported via unit train, where a unit train is defined as one locomotive pulling 100 railcars loaded with coal. The locomotive is powered by a 4,400 horsepower diesel engine (General Electric, 2008) and each car has a 100-ton coal capacity (NETL, 2007).

GHG emissions for train transport are evaluated based on typical diesel combustion emissions for a locomotive engine. Loss of coal during transport is assumed to be equal to the fugitive dust emissions; loss during loading at the mine is assumed to be included in the coal reject rate and no loss is assumed during unloading. It is assumed that the majority of the railway connecting the coal mine and the energy conversion facility is existing infrastructure. An assumed 25-mile rail spur was constructed between the energy conversion facility and the primary railway.

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Appendix B:
Inventory Results in Alternate Units

Table B-1: Upstream Greenhouse Gas Inventory Results for Natural Gas

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Avg. Gas	CO_2	5.93E+00	1.05E+00	6.98E+00	2.69E+00	4.76E-01	3.16E+00	2.55E+00	4.51E-04	3.00E-03	1.22E+01	2.16E+00	1.43E+01
	N_2O	1.85E-04	2.02E-05	2.05E-04	8.39E-05	9.17E-06	9.31E-05	7.95E-05	8.69E-06	8.82E-05	3.80E-04	4.15E-05	4.22E-04
	CH_4	6.42E-01	2.14E-01	8.56E-01	2.91E-01	9.69E-02	3.88E-01	2.76E-01	9.18E-02	3.68E-01	1.32E+00	4.39E-01	1.76E+00
	CO_2e (20-year)	52.2	16.4	68.6	23.7	7.5	31.1	22.4	7.1	29.5	107.2	33.8	141.0
	CO_2e (100-year)	22.0	6.4	28.4	10.0	2.9	12.9	9.5	2.7	12.2	45.3	13.1	58.4
	CO_2e (500-year)	10.8	2.7	13.5	4.9	1.2	6.1	4.7	1.2	5.8	22.3	5.5	27.8
Conv. Gas	CO_2	6.34E+00	1.05E+00	7.38E+00	2.87E+00	4.76E-01	3.35E+00	2.72E+00	4.51E-01	3.17E+00	1.30E+01	2.16E+00	1.52E+01
	N_2O	2.14E-04	2.02E-05	2.35E-04	9.72E-05	9.17E-06	1.06E-04	9.22E-05	8.69E-06	1.01E-04	4.40E-04	4.15E-05	4.82E-04
	CH_4	5.29E-01	2.14E-01	7.43E-01	2.40E-01	9.69E-02	3.37E-01	2.28E-01	9.18E-02	3.19E-01	1.09E+00	4.39E-01	1.53E+00
	CO_2e (20-year)	44.5	16.4	60.9	20.2	7.5	27.6	19.1	7.1	26.2	91.4	33.8	125.2
	CO_2e (100-year)	19.6	6.4	26.0	8.9	2.9	11.8	8.4	2.7	11.2	40.3	13.1	53.5
	CO_2e (500-year)	10.4	2.7	13.1	4.7	1.2	5.9	4.5	1.2	5.6	21.3	5.5	26.8
UnConv. Gas	CO_2	5.60E+00	1.05E+00	6.65E+00	2.54E+00	4.76E-01	3.02E+00	2.41E+00	4.51E-01	2.86E+00	1.15E+01	2.16E+00	1.37E+01
	N_2O	1.62E-04	2.02E-05	1.82E-04	7.33E-05	9.17E-06	8.25E-05	6.95E-05	8.69E-06	7.82E-05	3.32E-04	4.15E-05	3.74E-04
	CH_4	7.32E-01	2.14E-01	9.45E-01	3.32E-01	9.69E-02	4.29E-01	3.15E-01	9.18E-02	4.06E-01	1.50E+00	4.39E-01	1.94E+00
	CO_2e (20-year)	58.3	16.4	74.8	26.5	7.5	33.9	25.1	7.1	32.1	119.8	33.8	153.6
	CO_2e (100-year)	23.9	6.4	30.3	10.9	2.9	13.8	10.3	2.7	13.0	49.2	13.1	62.3
	CO_2e (500-year)	11.2	2.7	13.9	5.1	1.2	6.3	4.8	1.2	6.0	23.0	5.5	28.5
Onshore Gas	CO_2	7.18E+00	1.05E+00	8.23E+00	3.26E+00	4.76E-01	3.74E+00	3.09E+00	4.51E-01	3.54E+00	1.48E+01	2.16E+00	1.69E+01
	N_2O	2.13E-04	2.02E-05	2.33E-04	9.66E-05	9.17E-06	1.06E-04	9.16E-05	8.69E-06	1.00E-04	4.38E-04	4.15E-05	4.79E-04
	CH_4	8.21E-01	2.14E-01	1.03E+00	3.72E-01	9.69E-02	4.69E-01	3.53E-01	9.18E-02	4.45E-01	1.69E+00	4.39E-01	2.12E+00
	CO_2e (20-year)	66.3	16.4	82.8	30.1	7.5	37.5	28.5	7.1	35.6	136.3	33.8	170.0
	CO_2e (100-year)	27.8	6.4	34.2	12.6	2.9	15.5	11.9	2.7	14.7	57.0	13.1	70.2
	CO_2e (500-year)	13.5	2.7	16.1	6.1	1.2	7.3	5.8	1.2	6.9	27.6	5.5	33.1
Offshore Gas	CO_2	5.37E+00	1.05E+00	6.42E+00	2.44E+00	4.76E-01	2.91E+00	2.31E+00	4.51E-01	2.76E+00	1.10E+01	2.16E+00	1.32E+01
	N_2O	2.55E-04	2.02E-05	2.75E-04	1.15E-04	9.17E-06	1.25E-04	1.09E-04	8.69E-06	1.18E-04	5.23E-04	4.15E-05	5.64E-04
	CH_4	9.71E-02	2.14E-01	3.11E-01	4.40E-02	9.69E-02	1.41E-01	4.17E-02	9.18E-02	1.34E-01	1.99E-01	4.39E-01	6.38E-01
	CO_2e (20-year)	12.4	16.4	28.9	5.6	7.5	13.1	5.3	7.1	12.4	25.5	33.8	59.3
	CO_2e (100-year)	7.9	6.4	14.3	3.6	2.9	6.5	3.4	2.7	6.1	16.2	13.1	29.3
	CO_2e (500-year)	6.1	2.7	8.8	2.8	1.2	4.0	2.6	1.2	3.8	12.6	5.5	18.1
Assoc. Gas	CO_2	5.04E+00	1.05E+00	6.09E+00	2.29E+00	4.76E-01	2.76E+00	2.17E+00	4.51E-01	2.62E+00	1.04E+01	2.16E+00	1.25E+01
	N_2O	1.42E-04	2.02E-05	1.62E-04	6.42E-05	9.17E-06	7.34E-05	6.09E-05	8.69E-06	6.96E-05	2.91E-04	4.15E-05	3.32E-04
	CH_4	2.82E-01	2.14E-01	4.96E-01	1.28E-01	9.69E-02	2.25E-01	1.21E-01	9.18E-02	2.13E-01	5.80E-01	4.39E-01	1.02E+00
	CO_2e (20-year)	25.4	16.4	41.8	11.5	7.5	19.0	10.9	7.1	18.0	52.2	33.8	85.9
	CO_2e (100-year)	12.1	6.4	18.5	5.5	2.9	8.4	5.2	2.7	8.0	24.9	13.1	38.1
	CO_2e (500-year)	7.2	2.7	9.9	3.3	1.2	4.5	3.1	1.2	4.2	14.8	5.5	20.3

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Tight Gas	CO_2	5.53E+00	1.05E+00	6.57E+00	2.51E+00	4.76E-01	2.98E+00	2.38E+00	4.51E-01	2.83E+00	1.13E+01	2.16E+00	1.35E+01
	N_2O	1.57E-04	2.02E-05	1.78E-04	7.14E-05	9.17E-06	8.06E-05	6.77E-05	8.69E-06	7.64E-05	3.23E-04	4.15E-05	3.65E-04
	CH_4	8.16E-01	2.14E-01	1.03E+00	3.70E-01	9.69E-02	4.67E-01	3.51E-01	9.18E-02	4.43E-01	1.68E+00	4.39E-01	2.11E+00
	CO_2e (20-year)	64.3	16.4	80.7	29.2	7.5	36.6	27.6	7.1	34.7	132.1	33.8	165.8
	CO_2e (100-year)	26.0	6.4	32.4	11.8	2.9	14.7	11.2	2.7	13.9	53.3	13.1	66.5
	CO_2e (500-year)	11.7	2.7	14.4	5.3	1.2	6.5	5.1	1.2	6.2	24.1	5.5	29.6
CBM Gas	CO_2	5.45E+00	1.05E+00	6.50E+00	2.47E+00	4.76E-01	2.95E+00	2.34E+00	4.51E-01	2.79E+00	1.12E+01	2.16E+00	1.33E+01
	N_2O	1.55E-04	2.02E-05	1.75E-04	7.03E-05	9.17E-06	7.95E-05	6.67E-05	8.69E-06	7.53E-05	3.18E-04	4.15E-05	3.60E-04
	CH_4	2.86E-01	2.14E-01	5.00E-01	1.30E-01	9.69E-02	2.27E-01	1.23E-01	9.18E-02	2.15E-01	5.88E-01	4.39E-01	1.03E+00
	CO_2e (20-year)	26.1	16.4	42.5	11.8	7.5	19.3	11.2	7.1	18.3	53.6	33.8	87.4
	CO_2e (100-year)	12.7	6.4	19.1	5.7	2.9	8.6	5.4	2.7	8.2	26.0	13.1	39.1
	CO_2e (500-year)	7.7	2.7	10.3	3.5	1.2	4.7	3.3	1.2	4.4	15.7	5.5	21.2
Shale Gas	CO_2	5.84E+00	1.05E+00	6.89E+00	2.65E+00	4.76E-01	3.13E+00	2.51E+00	4.51E-01	2.96E+00	1.20E+01	2.16E+00	1.42E+01
	N_2O	1.74E-04	2.02E-05	1.94E-04	7.89E-05	9.17E-06	8.81E-05	7.48E-05	8.69E-06	8.35E-05	3.57E-04	4.15E-05	3.99E-04
	CH_4	8.07E-01	2.14E-01	1.02E+00	3.66E-01	9.69E-02	4.63E-01	3.47E-01	9.18E-02	4.39E-01	1.66E+00	4.39E-01	2.10E+00
	CO_2e (20-year)	64.0	16.4	80.5	29.0	7.5	36.5	27.5	7.1	34.6	131.5	33.8	165.3
	CO_2e (100-year)	26.1	6.4	32.5	11.8	2.9	14.7	11.2	2.7	14.0	53.6	13.1	66.7
	CO_2e (500-year)	12.0	2.7	14.7	5.5	1.2	6.7	5.2	1.2	6.3	24.7	5.5	30.2
LNG Gas	CO_2	2.93E+01	1.05E+00	3.04E+01	1.33E+01	4.76E-01	1.38E+01	1.26E+01	4.51E-01	1.31E+01	6.02E+01	2.16E+00	6.24E+01
	N_2O	3.42E-04	2.02E-05	3.62E-04	1.55E-04	9.17E-06	1.64E-04	1.47E-04	8.69E-06	1.56E-04	7.02E-04	4.15E-05	7.44E-04
	CH_4	2.78E-01	2.14E-01	4.91E-01	1.26E-01	9.69E-02	2.23E-01	1.19E-01	9.18E-02	2.11E-01	5.70E-01	4.39E-01	1.01E+00
	CO_2e (20-year)	49.4	16.4	65.8	22.4	7.5	29.9	21.2	7.1	28.3	101.5	33.8	135.2
	CO_2e (100-year)	36.4	6.4	42.8	16.5	2.9	19.4	15.6	2.7	18.4	74.7	13.1	87.8
	CO_2e (500-year)	31.5	2.7	34.2	14.3	1.2	15.5	13.5	1.2	14.7	64.7	5.5	70.1

Table B-2: Upstream Greenhouse Gas Inventory Results for Marginal Natural Gas

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Marg. Onshore Gas	CO_2	5.11E+00	1.05E+00	6.16E+00	2.32E+00	4.76E-01	2.79E+00	2.20E+00	4.51E-01	2.65E+00	1.05E+01	2.16E+00	1.26E+01
	N_2O	1.44E-04	2.02E-05	1.64E-04	6.53E-05	9.17E-06	7.44E-05	6.19E-05	8.69E-06	7.06E-05	2.96E-04	4.15E-05	3.37E-04
	CH_4	3.41E-01	2.14E-01	5.55E-01	1.55E-01	9.69E-02	2.52E-01	1.47E-01	9.18E-02	2.38E-01	7.01E-01	4.39E-01	1.14E+00
	CO_2e (20-year)	29.7	16.4	46.1	13.5	7.5	20.9	12.8	7.1	19.8	61.0	33.8	94.8
	CO_2e (100-year)	13.7	6.4	20.1	6.2	2.9	9.1	5.9	2.7	8.6	28.1	13.1	41.2
	CO_2e (500-year)	7.7	2.7	10.4	3.5	1.2	4.7	3.3	1.2	4.5	15.9	5.5	21.4
Marg. Offshore Gas	CO_2	5.34E+00	1.05E+00	6.39E+00	2.42E+00	4.76E-01	2.90E+00	2.30E+00	4.51E-01	2.75E+00	1.10E+01	2.16E+00	1.31E+01
	N_2O	2.54E-04	2.02E-05	2.74E-04	1.15E-04	9.17E-06	1.24E-04	1.09E-04	8.69E-06	1.18E-04	5.21E-04	4.15E-05	5.62E-04
	CH_4	9.01E-02	2.14E-01	3.04E-01	4.09E-02	9.69E-02	1.38E-01	3.87E-02	9.18E-02	1.31E-01	1.85E-01	4.39E-01	6.24E-01
	CO_2e (20-year)	11.9	16.4	28.3	5.4	7.5	12.9	5.1	7.1	12.2	24.4	33.8	58.2
	CO_2e (100-year)	7.7	6.4	14.1	3.5	2.9	6.4	3.3	2.7	6.0	15.8	13.1	28.9
	CO_2e (500-year)	6.1	2.7	8.7	2.8	1.2	4.0	2.6	1.2	3.8	12.5	5.5	18.0

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ			ton/cf		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Marg. Assoc. Gas	CO_2	4.91E+00	1.05E+00	5.96E+00	2.23E+00	4.76E-01	2.70E+00	2.11E+00	4.51E-01	2.56E+00	1.01E+01	2.16E+00	1.22E+01
	N_2O	1.37E-04	2.02E-05	1.57E-04	6.22E-05	9.17E-06	7.14E-05	5.90E-05	8.69E-06	6.77E-05	2.82E-04	4.15E-05	3.23E-04
	CH_4	2.82E-01	2.14E-01	4.95E-01	1.28E-01	9.69E-02	2.25E-01	1.21E-01	9.18E-02	2.13E-01	5.78E-01	4.39E-01	1.02E+00
	CO_2e (20-year)	25.2	16.4	41.7	11.4	7.5	18.9	10.8	7.1	17.9	51.8	33.8	85.6
	CO_2e (100-year)	12.0	6.4	18.4	5.4	2.9	8.3	5.2	2.7	7.9	24.6	13.1	37.8
	CO_2e (500-year)	7.1	2.7	9.7	3.2	1.2	4.4	3.0	1.2	4.2	14.5	5.5	20.0
Marg. Tight Gas	CO_2	5.53E+00	1.05E+00	6.57E+00	2.51E+00	4.76E-01	2.98E+00	2.38E+00	4.51E-01	2.83E+00	1.13E+01	2.16E+00	1.35E+01
	N_2O	1.57E-04	2.02E-05	1.78E-04	7.14E-05	9.17E-06	8.06E-05	6.77E-05	8.69E-06	7.64E-05	3.23E-04	4.15E-05	3.65E-04
	CH_4	8.16E-01	2.14E-01	1.03E+00	3.70E-01	9.69E-02	4.67E-01	3.51E-01	9.18E-02	4.43E-01	1.68E+00	4.39E-01	2.11E+00
	SF_6	6.49E-09	2.50E-09	8.99E-09	2.94E-09	1.13E-09	4.08E-09	2.79E-09	1.07E-09	3.86E-09	1.33E-08	5.13E-09	1.85E-08
	CO_2e (20-year)	64.3	16.4	80.7	29.2	7.5	36.6	27.6	7.1	34.7	132.1	33.8	165.8
	CO_2e (100-year)	26.0	6.4	32.4	11.8	2.9	14.7	11.2	2.7	13.9	53.3	13.1	66.5
	CO_2e (500-year)	11.7	2.7	14.4	5.3	1.2	6.5	5.1	1.2	6.2	24.1	5.5	29.6
Marg. Shale Gas	CO_2	5.84E+00	1.05E+00	6.89E+00	2.65E+00	4.76E-01	3.13E+00	2.51E+00	4.51E-01	2.96E+00	1.20E+01	2.16E+00	1.42E+01
	N_2O	1.74E-04	2.02E-05	1.94E-04	7.89E-05	9.17E-06	8.81E-05	7.48E-05	8.69E-06	8.35E-05	3.57E-04	4.15E-05	3.99E-04
	CH_4	8.07E-01	2.14E-01	1.02E+00	3.66E-01	9.69E-02	4.63E-01	3.47E-01	9.18E-02	4.39E-01	1.66E+00	4.39E-01	2.10E+00
	CO_2e (20-year)	64.0	16.4	80.5	29.0	7.5	36.5	27.5	7.1	34.6	131.5	33.8	165.3
	CO_2e (100-year)	26.1	6.4	32.5	11.8	2.9	14.7	11.2	2.7	14.0	53.6	13.1	66.7
	CO_2e (500-year)	12.0	2.7	14.7	5.5	1.2	6.7	5.2	1.2	6.3	24.7	5.5	30.2
Marg. CBM Gas	CO_2	5.67E+00	1.05E+00	6.72E+00	2.57E+00	4.76E-01	3.05E+00	2.44E+00	4.51E-01	2.89E+00	1.16E+01	2.16E+00	1.38E+01
	N_2O	1.62E-04	2.02E-05	1.83E-04	7.36E-05	9.17E-06	8.28E-05	6.98E-05	8.69E-06	7.85E-05	3.33E-04	4.15E-05	3.75E-04
	CH_4	2.88E-01	2.14E-01	5.02E-01	1.31E-01	9.69E-02	2.28E-01	1.24E-01	9.18E-02	2.16E-01	5.92E-01	4.39E-01	1.03E+00
	CO_2e (20-year)	26.5	16.4	42.9	12.0	7.5	19.5	11.4	7.1	18.4	54.4	33.8	88.1
	CO_2e (100-year)	12.9	6.4	19.3	5.9	2.9	8.8	5.6	2.7	8.3	26.6	13.1	39.7
	CO_2e (500-year)	7.9	2.7	10.6	3.6	1.2	4.8	3.4	1.2	4.5	16.2	5.5	21.7
Marg. LNG Gas	CO_2	2.93E+01	1.05E+00	3.03E+01	1.33E+01	4.76E-01	1.38E+01	1.26E+01	4.51E-01	1.30E+01	6.01E+01	2.16E+00	6.23E+01
	N_2O	3.41E-04	2.02E-05	3.61E-04	1.54E-04	9.17E-06	1.64E-04	1.46E-04	8.69E-06	1.55E-04	7.00E-04	4.15E-05	7.41E-04
	CH_4	2.70E-01	2.14E-01	4.83E-01	1.22E-01	9.69E-02	2.19E-01	1.16E-01	9.18E-02	2.08E-01	5.54E-01	4.39E-01	9.92E-01
	CO_2e (20-year)	48.8	16.4	65.2	22.1	7.5	29.6	21.0	7.1	28.0	100.2	33.8	133.9
	CO_2e (100-year)	36.1	6.4	42.5	16.4	2.9	19.3	15.5	2.7	18.3	74.2	13.1	87.3
	CO_2e (500-year)	31.4	2.7	34.1	14.2	1.2	15.4	13.5	1.2	14.6	64.5	5.5	69.9

Table B-3: Upstream Greenhouse Gas Inventory Results for Coal

Feedstock	GHG	lb/MMBtu			kg/MMBtu			g/MJ		
		RMA	RMT	Total	RMA	RMT	Total	RMA	RMT	Total
Avg. Coal	CO_2	1.32E+00	1.33E+00	2.64E+00	5.97E-01	6.02E-01	1.20E+00	5.66E-01	5.71E-01	1.14E+00
	N_2O	5.29E-04	3.21E-05	5.61E-04	2.40E-04	1.46E-05	2.54E-04	2.27E-04	1.38E-05	2.41E-04
	CH_4	3.78E-01	7.23E-04	3.79E-01	1.72E-01	3.28E-04	1.72E-01	1.63E-01	3.11E-04	1.63E-01
	CO_2e (20-year)	28.7	1.4	30.1	13.0	0.6	13.7	12.3	0.6	12.9
	CO_2e (100-year)	10.9	1.4	12.3	5.0	0.6	5.6	4.7	0.6	5.3
	CO_2e (500-year)	4.3	1.3	5.6	1.9	0.6	2.5	1.8	0.6	2.4
Illinois No. 6 Coal	CO_2	2.53E+00	1.33E+00	3.86E+00	1.15E+00	6.02E-01	1.75E+00	1.09E+00	5.71E-01	1.66E+00
	N_2O	3.97E-05	3.21E-05	7.18E-05	1.80E-05	1.46E-05	3.26E-05	1.71E-05	1.38E-05	3.09E-05
	CH_4	9.40E-01	7.23E-04	9.41E-01	4.27E-01	3.28E-04	4.27E-01	4.04E-01	3.11E-04	4.05E-01
	SF_6	4.98E-07	5.47E-12	4.98E-07	2.26E-07	2.48E-12	2.26E-07	2.14E-07	2.35E-12	2.14E-07
	CO_2e (20-year)	70.3	1.4	71.7	31.9	0.6	32.5	30.2	0.6	30.8
	CO_2e (100-year)	26.1	1.4	27.4	11.8	0.6	12.4	11.2	0.6	11.8
	CO_2e (500-year)	9.7	1.3	11.0	4.4	0.6	5.0	4.2	0.6	4.7
PRB Coal	CO_2	7.73E-01	1.33E+00	2.10E+00	3.51E-01	6.02E-01	9.53E-01	3.32E-01	5.71E-01	9.03E-01
	N_2O	7.48E-04	3.21E-05	7.80E-04	3.39E-04	1.46E-05	3.54E-04	3.22E-04	1.38E-05	3.35E-04
	CH_4	1.26E-01	7.23E-04	1.26E-01	5.70E-02	3.28E-04	5.74E-02	5.41E-02	3.11E-04	5.44E-02
	CO_2e (20-year)	10.0	1.4	11.4	4.6	0.6	5.2	4.3	0.6	4.9
	CO_2e (100-year)	4.1	1.4	5.5	1.9	0.6	2.5	1.8	0.6	2.4
	CO_2e (500-year)	1.8	1.3	3.2	0.8	0.6	1.4	0.8	0.6	1.4

Table B-4: Upstream Greenhouse Gas Inventory Results for Natural Gas-fired Power Generation

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
Fleet Baseload (Avg. Gas)	CO_2	5.81E+01	1.01E+01	8.75E+02	0.00E+00	9.43E+02	2.63E+01	4.60E+00	3.97E+02	0.00E+00	4.28E+02	7.31E+00	1.28E+00	1.10E+02	0.00E+00	1.19E+02
	N_2O	1.81E-03	1.96E-04	2.45E-03	0.00E+00	4.45E-03	8.22E-04	8.88E-05	1.11E-03	0.00E+00	2.02E-03	2.28E-04	2.47E-05	3.08E-04	0.00E+00	5.61E-04
	CH_4	6.31E+00	2.09E+00	2.44E-02	0.00E+00	8.42E+00	2.86E+00	9.46E-01	1.11E-02	0.00E+00	3.82E+00	7.95E-01	2.63E-01	3.07E-03	0.00E+00	1.06E+00
	SF_6	4.80E-07	4.38E-12	0.00E+00	3.16E-04	3.16E-04	2.18E-07	1.99E-12	0.00E+00	1.43E-04	1.44E-04	6.04E-08	5.51E-13	0.00E+00	3.98E-05	3.99E-05
	CO_2e (20-year)	513.0	160.4	877.0	5.2	1,555.6	232.7	72.8	397.8	2.3	705.6	64.6	20.2	110.5	0.6	196.0
	CO_2e (100-year)	216.4	62.4	875.9	7.2	1,161.8	98.2	28.3	397.3	3.3	527.0	27.3	7.9	110.4	0.9	146.4
	CO_2e (500-year)	106.3	26.0	875.1	10.3	1,017.7	48.2	11.8	396.9	4.7	461.6	13.4	3.3	110.3	1.3	128.2
Fleet Baseload (Conv. Gas)	CO_2	6.22E+01	1.01E+01	8.75E+02	0.00E+00	9.47E+02	2.82E+01	4.60E+00	3.97E+02	0.00E+00	4.30E+02	7.84E+00	1.28E+00	1.10E+02	0.00E+00	1.19E+02
	N_2O	2.10E-03	1.96E-04	2.45E-03	0.00E+00	4.75E-03	9.55E-04	8.88E-05	1.11E-03	0.00E+00	2.15E-03	2.65E-04	2.47E-05	3.08E-04	0.00E+00	5.98E-04
	CH_4	5.26E+00	2.09E+00	2.44E-02	0.00E+00	7.37E+00	2.38E+00	9.46E-01	1.11E-02	0.00E+00	3.34E+00	6.62E-01	2.63E-01	3.07E-03	0.00E+00	9.28E-01
	SF_6	5.26E-08	4.38E-12	0.00E+00	3.16E-04	3.16E-04	2.39E-08	1.99E-12	0.00E+00	1.43E-04	1.43E-04	6.63E-09	5.51E-13	0.00E+00	3.98E-05	3.98E-05
	CO_2e (20-year)	441.3	160.4	877.0	5.2	1,483.9	200.2	72.8	397.8	2.3	673.1	55.6	20.2	110.5	0.6	187.0
	CO_2e (100-year)	194.3	62.4	875.9	7.2	1,139.7	88.1	28.3	397.3	3.3	517.0	24.5	7.9	110.4	0.9	143.6
	CO_2e (500-year)	102.5	26.0	875.1	10.3	1,013.9	46.5	11.8	396.9	4.7	459.9	12.9	3.3	110.3	1.3	127.8

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
Fleet Baseload (UnConv. Gas)	CO_2	5.47E+01	1.01E+01	8.75E+02	0.00E+00	9.39E+02	2.48E+01	4.60E+00	3.97E+02	0.00E+00	4.26E+02	6.90E+00	1.28E+00	1.10E+02	0.00E+00	1.18E+02
	N_2O	1.58E-03	1.96E-04	2.45E-03	0.00E+00	4.22E-03	7.17E-04	8.88E-05	1.11E-03	0.00E+00	1.91E-03	1.99E-04	2.47E-05	3.08E-04	0.00E+00	5.32E-04
	CH_4	7.15E+00	2.09E+00	2.44E-02	0.00E+00	9.26E+00	3.24E+00	9.46E-01	1.11E-02	0.00E+00	4.20E+00	9.01E-01	2.63E-01	3.07E-03	0.00E+00	1.17E+00
	SF_6	8.20E-07	4.38E-12	0.00E+00	3.16E-04	3.17E-04	3.72E-07	1.99E-12	0.00E+00	1.43E-04	1.44E-04	1.03E-07	5.51E-13	0.00E+00	3.98E-05	3.99E-05
	CO_2e (20-year)	570.1	160.4	877.0	5.2	1,612.7	258.6	72.8	397.8	2.3	731.5	71.8	20.2	110.5	0.6	203.2
	CO_2e (100-year)	234.0	62.4	875.9	7.2	1,179.5	106.1	28.3	397.3	3.3	535.0	29.5	7.9	110.4	0.9	148.6
	CO_2e (500-year)	109.4	26.0	875.1	10.3	1,020.8	49.6	11.8	396.9	4.7	463.0	13.8	3.3	110.3	1.3	128.6
Fleet Baseload (Marg. Onshore Gas)	CO_2	4.99E+01	1.01E+01	8.75E+02	0.00E+00	9.35E+02	2.26E+01	4.60E+00	3.97E+02	0.00E+00	4.24E+02	6.29E+00	1.28E+00	1.10E+02	0.00E+00	1.18E+02
	N_2O	1.41E-03	1.96E-04	2.45E-03	0.00E+00	4.05E-03	6.38E-04	8.88E-05	1.11E-03	0.00E+00	1.84E-03	1.77E-04	2.47E-05	3.08E-04	0.00E+00	5.10E-04
	CH_4	3.33E+00	2.09E+00	2.44E-02	0.00E+00	5.44E+00	1.51E+00	9.46E-01	1.11E-02	0.00E+00	2.47E+00	4.20E-01	2.63E-01	3.07E-03	0.00E+00	6.86E-01
	SF_6	9.27E-09	4.38E-12	0.00E+00	3.16E-04	3.16E-04	4.20E-09	1.99E-12	0.00E+00	1.43E-04	1.43E-04	1.17E-09	5.51E-13	0.00E+00	3.98E-05	3.98E-05
	CO_2e (20-year)	290.4	160.4	877.0	5.2	1,332.9	131.7	72.8	397.8	2.3	604.6	36.6	20.2	110.5	0.6	167.9
	CO_2e (100-year)	133.7	62.4	875.9	7.2	1,079.1	60.6	28.3	397.3	3.3	489.5	16.8	7.9	110.4	0.9	136.0
	CO_2e (500-year)	75.5	26.0	875.1	10.3	986.9	34.2	11.8	396.9	4.7	447.6	9.5	3.3	110.3	1.3	124.3
GTSC (Avg. Gas)	CO_2	7.26E+01	1.27E+01	1.33E+03	0.00E+00	1.42E+03	3.29E+01	5.75E+00	6.04E+02	0.00E+00	6.42E+02	9.15E+00	1.60E+00	1.68E+02	0.00E+00	1.78E+02
	N_2O	2.27E-03	2.45E-04	2.86E-05	0.00E+00	2.54E-03	1.03E-03	1.11E-04	1.30E-05	0.00E+00	1.15E-03	2.86E-04	3.08E-05	3.61E-06	0.00E+00	3.20E-04
	CH_4	7.90E+00	2.61E+00	2.64E-03	0.00E+00	1.05E+01	3.58E+00	1.18E+00	1.20E-03	0.00E+00	4.77E+00	9.95E-01	3.29E-01	3.32E-04	0.00E+00	1.32E+00
	SF_6	6.00E-07	5.48E-12	4.34E-08	3.16E-04	3.17E-04	2.72E-07	2.48E-12	1.97E-08	1.43E-04	1.44E-04	7.56E-08	6.90E-13	5.47E-09	3.98E-05	3.99E-05
	CO_2e (20-year)	641.8	200.7	1,330.7	5.2	2,178.4	291.1	91.0	603.6	2.3	988.1	80.9	25.3	167.7	0.6	274.5
	CO_2e (100-year)	270.7	78.0	1,330.6	7.2	1,686.6	122.8	35.4	603.6	3.3	765.0	34.1	9.8	167.7	0.9	212.5
	CO_2e (500-year)	133.0	32.6	1,330.6	10.3	1,506.4	60.3	14.8	603.5	4.7	683.3	16.8	4.1	167.6	1.3	189.8
NGCC (Avg. Gas)	CO_2	4.71E+01	8.23E+00	8.66E+02	0.00E+00	9.22E+02	2.14E+01	3.73E+00	3.93E+02	0.00E+00	4.18E+02	5.94E+00	1.04E+00	1.09E+02	0.00E+00	1.16E+02
	N_2O	1.47E-03	1.59E-04	3.33E-05	0.00E+00	1.66E-03	6.67E-04	7.21E-05	1.51E-05	0.00E+00	7.55E-04	1.85E-04	2.00E-05	4.20E-06	0.00E+00	2.10E-04
	CH_4	5.12E+00	1.69E+00	1.31E-03	0.00E+00	6.82E+00	2.32E+00	7.68E-01	5.94E-04	0.00E+00	3.09E+00	6.46E-01	2.13E-01	1.65E-04	0.00E+00	8.59E-01
	SF_6	3.89E-07	3.55E-12	7.55E-07	3.16E-04	3.17E-04	1.77E-07	1.61E-12	3.42E-07	1.43E-04	1.44E-04	4.91E-08	4.48E-13	9.51E-08	3.98E-05	4.00E-05
	CO_2e (20-year)	416.5	130.2	866.5	5.2	1,418.5	188.9	59.1	393.1	2.3	643.4	52.5	16.4	109.2	0.6	178.7
	CO_2e (100-year)	175.7	50.6	866.5	7.2	1,100.0	79.7	23.0	393.0	3.3	499.0	22.1	6.4	109.2	0.9	138.6
	CO_2e (500-year)	86.3	21.1	866.5	10.3	984.2	39.2	9.6	393.0	4.7	446.4	10.9	2.7	109.2	1.3	124.0
NGCC/ccs (Avg. Gas)	CO_2	5.52E+01	9.65E+00	1.13E+02	0.00E+00	1.78E+02	2.51E+01	4.38E+00	5.13E+01	0.00E+00	8.07E+01	6.96E+00	1.22E+00	1.42E+01	0.00E+00	2.24E+01
	N_2O	1.72E-03	1.86E-04	5.18E-05	0.00E+00	1.96E-03	7.82E-04	8.45E-05	2.35E-05	0.00E+00	8.90E-04	2.17E-04	2.35E-05	6.53E-06	0.00E+00	2.47E-04
	CH_4	6.01E+00	1.99E+00	1.71E-03	0.00E+00	7.99E+00	2.72E+00	9.01E-01	7.78E-04	0.00E+00	3.63E+00	7.57E-01	2.50E-01	2.16E-04	0.00E+00	1.01E+00
	SF_6	4.57E-07	4.16E-12	8.81E-07	3.16E-04	3.17E-04	2.07E-07	1.89E-12	4.00E-07	1.43E-04	1.44E-04	5.75E-08	5.25E-13	1.11E-07	3.98E-05	4.00E-05
	CO_2e (20-year)	488.2	152.7	113.2	5.2	759.2	221.5	69.2	51.3	2.3	344.4	61.5	19.2	14.3	0.6	95.7
	CO_2e (100-year)	205.9	59.3	113.1	7.2	385.6	93.4	26.9	51.3	3.3	174.9	25.9	7.5	14.3	0.9	48.6
	CO_2e (500-year)	101.2	24.8	113.1	10.3	249.3	45.9	11.2	51.3	4.7	113.1	12.7	3.1	14.2	1.3	31.4

Table B-5: Upstream Greenhouse Gas Inventory Results for Coal-fired Power Generation

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
Fleet Baseload (Avg. Coal)	CO_2	1.38E+01	1.39E+01	2.33E+03	0.00E+00	2.35E+03	6.26E+00	6.31E+00	1.06E+03	0.00E+00	1.07E+03	1.74E+00	1.75E+00	2.93E+02	0.00E+00	2.97E+02
	N_2O	5.54E-03	3.36E-04	3.99E-02	0.00E+00	4.58E-02	2.51E-03	1.53E-04	1.81E-02	0.00E+00	2.08E-02	6.98E-04	4.24E-05	5.03E-03	0.00E+00	5.77E-03
	CH_4	3.96E+00	7.57E-03	2.67E-02	0.00E+00	4.00E+00	1.80E+00	3.43E-03	1.21E-02	0.00E+00	1.81E+00	4.99E-01	9.54E-04	3.37E-03	0.00E+00	5.04E-01
	SF_6	1.77E-06	5.73E-11	0.00E+00	3.16E-04	3.18E-04	8.03E-07	2.60E-11	0.00E+00	1.43E-04	1.44E-04	2.23E-07	7.22E-12	0.00E+00	3.98E-05	4.00E-05
	CO_2e (20-year)	300.8	14.5	2,340.1	5.2	2,660.6	136.4	6.6	1,061.5	2.3	1,206.8	37.9	1.8	294.9	0.6	335.2
	CO_2e (100-year)	114.6	14.2	2,339.2	7.2	2,475.2	52.0	6.4	1,061.1	3.3	1,122.7	14.4	1.8	294.7	0.9	311.9
	CO_2e (500-year)	44.8	14.0	2,333.0	10.3	2,402.1	20.3	6.4	1,058.2	4.7	1,089.6	5.6	1.8	294.0	1.3	302.7
EXPC (Illinois No. 6 Coal)	CO_2	2.24E+01	1.18E+01	2.23E+03	0.00E+00	2.27E+03	1.02E+01	5.34E+00	1.01E+03	0.00E+00	1.03E+03	2.83E+00	1.48E+00	2.81E+02	0.00E+00	2.85E+02
	N_2O	3.52E-04	2.85E-04	3.77E-02	0.00E+00	3.83E-02	1.60E-04	1.29E-04	1.71E-02	0.00E+00	1.74E-02	4.44E-05	3.59E-05	4.75E-03	0.00E+00	4.83E-03
	CH_4	8.35E+00	6.42E-03	2.51E-02	0.00E+00	8.38E+00	3.79E+00	2.91E-03	1.14E-02	0.00E+00	3.80E+00	1.05E+00	8.08E-04	3.17E-03	0.00E+00	1.06E+00
	SF_6	4.42E-06	4.85E-11	6.11E-07	3.16E-04	3.21E-04	2.00E-06	2.20E-11	2.77E-07	1.43E-04	1.46E-04	5.57E-07	6.11E-12	7.70E-08	3.98E-05	4.04E-05
	CO_2e (20-year)	623.7	12.3	2,243.5	5.2	2,884.7	282.9	5.6	1,017.6	2.3	1,308.5	78.6	1.6	282.7	0.6	363.5
	CO_2e (100-year)	231.4	12.0	2,242.7	7.2	2,493.3	104.9	5.5	1,017.3	3.3	1,130.9	29.2	1.5	282.6	0.9	314.1
	CO_2e (500-year)	86.1	11.9	2,236.8	10.3	2,345.0	39.0	5.4	1,014.6	4.7	1,063.7	10.8	1.5	281.8	1.3	295.5
IGCC (Illinois No. 6 Coal)	CO_2	1.98E+01	1.04E+01	1.89E+03	0.00E+00	1.92E+03	8.98E+00	4.72E+00	8.57E+02	0.00E+00	8.71E+02	2.49E+00	1.31E+00	2.38E+02	0.00E+00	2.42E+02
	N_2O	3.11E-04	2.52E-04	4.67E-05	0.00E+00	6.09E-04	1.41E-04	1.14E-04	2.12E-05	0.00E+00	2.76E-04	3.92E-05	3.17E-05	5.89E-06	0.00E+00	7.68E-05
	CH_4	7.37E+00	5.66E-03	9.58E-03	0.00E+00	7.38E+00	3.34E+00	2.57E-03	4.35E-03	0.00E+00	3.35E+00	9.28E-01	7.13E-04	1.21E-03	0.00E+00	9.30E-01
	SF_6	3.90E-06	4.28E-11	7.69E-07	3.16E-04	3.21E-04	1.77E-06	1.94E-11	3.49E-07	1.43E-04	1.45E-04	4.91E-07	5.40E-12	9.69E-08	3.98E-05	4.04E-05
	CO_2e (20-year)	550.4	10.9	1,890.8	5.2	2,457.2	249.7	4.9	857.7	2.3	1,114.6	69.3	1.4	238.2	0.6	309.6
	CO_2e (100-year)	204.2	10.6	1,890.4	7.2	2,112.4	92.6	4.8	857.5	3.3	958.2	25.7	1.3	238.2	0.9	266.2
	CO_2e (500-year)	76.0	10.5	1,890.2	10.3	1,987.0	34.5	4.8	857.4	4.7	901.3	9.6	1.3	238.2	1.3	250.4
IGCC/ccs (Illinois No. 6 Coal)	CO_2	2.33E+01	1.22E+01	2.46E+02	0.00E+00	2.81E+02	1.06E+01	5.55E+00	1.11E+02	0.00E+00	1.28E+02	2.94E+00	1.54E+00	3.10E+01	0.00E+00	3.54E+01
	N_2O	3.66E-04	2.96E-04	9.13E-05	0.00E+00	7.54E-04	1.66E-04	1.34E-04	4.14E-05	0.00E+00	3.42E-04	4.61E-05	3.73E-05	1.15E-05	0.00E+00	9.50E-05
	CH_4	8.67E+00	6.67E-03	1.15E-02	0.00E+00	8.69E+00	3.93E+00	3.02E-03	5.20E-03	0.00E+00	3.94E+00	1.09E+00	8.40E-04	1.45E-03	0.00E+00	1.10E+00
	SF_6	4.59E-06	5.04E-11	8.72E-07	3.16E-04	3.21E-04	2.08E-06	2.29E-11	3.96E-07	1.43E-04	1.46E-04	5.78E-07	6.35E-12	1.10E-07	3.98E-05	4.05E-05
	CO_2e (20-year)	648.1	12.8	246.6	5.2	912.7	294.0	5.8	111.9	2.3	414.0	81.7	1.6	31.1	0.6	115.0
	CO_2e (100-year)	240.4	12.5	246.1	7.2	506.2	109.0	5.7	111.6	3.3	229.6	30.3	1.6	31.0	0.9	63.8
	CO_2e (500-year)	89.5	12.3	245.9	10.3	358.0	40.6	5.6	111.5	4.7	162.4	11.3	1.6	31.0	1.3	45.1

Power Plant (Feedstock)	GHG	lb/MWh					kg/MWh					g/MJ				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
SCPC (Illinois No. 6 Coal)	CO_2	1.94E+01	1.02E+01	1.91E+03	0.00E+00	1.94E+03	8.78E+00	4.61E+00	8.66E+02	0.00E+00	8.79E+02	2.44E+00	1.28E+00	2.41E+02	0.00E+00	2.44E+02
	N_2O	3.04E-04	2.46E-04	6.99E-05	0.00E+00	6.20E-04	1.38E-04	1.12E-04	3.17E-05	0.00E+00	2.81E-04	3.83E-05	3.10E-05	8.81E-06	0.00E+00	7.81E-05
	CH_4	7.20E+00	5.53E-03	8.98E-03	0.00E+00	7.22E+00	3.27E+00	2.51E-03	4.07E-03	0.00E+00	3.27E+00	9.07E-01	6.97E-04	1.13E-03	0.00E+00	9.09E-01
	SF_6	3.81E-06	4.19E-11	8.26E-07	3.16E-04	3.21E-04	1.73E-06	1.90E-11	3.74E-07	1.43E-04	1.45E-04	4.80E-07	5.27E-12	1.04E-07	3.98E-05	4.04E-05
	CO_2e (20-year)	538.0	10.6	1,910.1	5.2	2,463.9	244.0	4.8	866.4	2.3	1,117.6	67.8	1.3	240.7	0.6	310.5
	CO_2e (100-year)	199.6	10.4	1,909.7	7.2	2,126.9	90.5	4.7	866.2	3.3	964.7	25.1	1.3	240.6	0.9	268.0
	CO_2e (500-year)	74.3	10.2	1,909.5	10.3	2,004.3	33.7	4.6	866.2	4.7	909.2	9.4	1.3	240.6	1.3	252.5
SCPC/ccs (Illinois No. 6 Coal)	CO_2	2.78E+01	1.46E+01	3.02E+02	0.00E+00	3.45E+02	1.26E+01	6.63E+00	1.37E+02	0.00E+00	1.56E+02	3.51E+00	1.84E+00	3.81E+01	0.00E+00	4.34E+01
	N_2O	4.37E-04	3.53E-04	1.07E-04	0.00E+00	8.97E-04	1.98E-04	1.60E-04	4.85E-05	0.00E+00	4.07E-04	5.50E-05	4.45E-05	1.35E-05	0.00E+00	1.13E-04
	CH_4	1.04E+01	7.95E-03	9.79E-03	0.00E+00	1.04E+01	4.69E+00	3.61E-03	4.44E-03	0.00E+00	4.70E+00	1.30E+00	1.00E-03	1.23E-03	0.00E+00	1.31E+00
	SF_6	5.48E-06	6.02E-11	8.34E-07	3.16E-04	3.22E-04	2.48E-06	2.73E-11	3.78E-07	1.43E-04	1.46E-04	6.90E-07	7.58E-12	1.05E-07	3.98E-05	4.06E-05
	CO_2e (20-year)	773.3	15.3	302.8	5.2	1,096.5	350.7	6.9	137.4	2.3	497.4	97.4	1.9	38.2	0.6	138.2
	CO_2e (100-year)	286.8	14.9	302.4	7.2	611.3	130.1	6.8	137.2	3.3	277.3	36.1	1.9	38.1	0.9	77.0
	CO_2e (500-year)	106.7	14.7	302.2	10.3	434.0	48.4	6.7	137.1	4.7	196.8	13.4	1.9	38.1	1.3	54.7